ANNUAL REPORT 2024

Solid growth. Low risk.
Repeatable performance.

TC Energy

FINANCIAL HIGHLIGHTS

25 CONSECUTIVE YEARS OF DIVIDEND INCREASES[1]

Comparable earnings per common share[2] (dollars)

2022	3.64
2023	3.78
2024	**3.73**

Comparable EBITDA[2] (millions of dollars)

2022	8,483
2023	9,472
2024	**10,049**

Comparable earnings[2] (millions of dollars)

2022	3,618
2023	3,896
2024	**3,865**

Net income per common share (dollars)

2022	0.01
2023	2.15
2024	**4.05**

Segmented earnings (millions of dollars)

2022	2,450
2023	5,097
2024	**7,964**

Net income attributable to common shares (millions of dollars)

2022	8
2023	2,217
2024	**4,199**

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 and 2022. Refer to the Discontinued operations section of our 2024 Annual MD&A for additional information.

2022	7,353
2023	7,980
2024	**7,890**

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 and 2022. Refer to the Discontinued operations section of our 2024 Annual MD&A for additional information.

2022	6,375
2023	7,268
2024	**7,696**

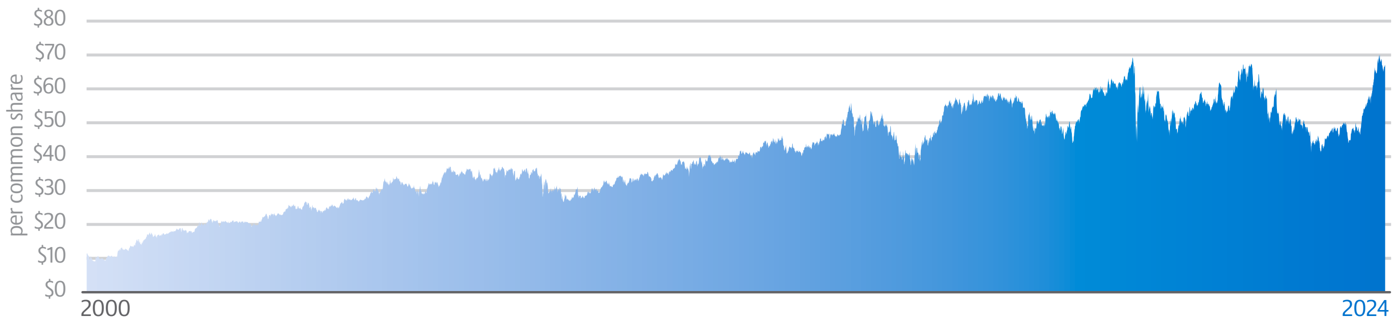
Dividends declared per common share (dollars)*

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

2022	3.60
2023	3.72
2024	**3.7025**

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.



Charts reflect continuing operations following the Spinoff Transaction unless otherwise noted. Prior years' results have been recast to reflect continuing operations only.

1 On February 14, 2025, we announced a quarterly dividend on our outstanding common shares of $0.85 per common share for the quarter ending March 31, 2025, which represents an increase of 3.3 per cent from TC Energy's proportionate allocation of the dividend following the Spinoff Transaction. This equates to an annual dividend of $3.40 per common share. This was the twenty-fifth consecutive year we have increased the dividend on our common shares and is consistent with our goal of growing our common share dividend at an average annual rate of three to five per cent.

*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 Non-GAAP measures section of the 2024 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 2024 Annual MD&A is available under TC Energy's profile on SEDAR+ at www.sedarplus.ca.*

***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 2024 Annual Report filed with Canadian securities regulators and the U.S. Securities and Exchange Commission and available at TCEnergy.com.*

LAND ACKNOWLEDGMENT

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

PROUDLY CONNECTING THE WORLD TO THE ENERGY IT NEEDS

We are a leader in North American energy infrastructure, with a rich history spanning more than seven decades. Our operations extend across three jurisdictions—Canada, the U.S. and Mexico—strategically positioning us to safely and efficiently move, generate and store the critical energy North America and the world rely on. 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 in every step and operational excellence.

We have renewed our strategic vision to focus on two core complementary pillars of our business—natural gas and power generation—addressing the global energy trilemma of energy security, affordability and sustainability. As global electrification accelerates the need for reliable energy, the demand for natural gas has never been higher. We continue to focus on our sustainability commitments, which reflect the interests of our business, Indigenous rights holders and stakeholders; positioning us for long-term success. We are committed to collectively advancing a lower-emissions energy system and expect to provide an update on our interim GHG emission reduction target in 2025 to reflect the impact of the Liquids Pipelines business spinoff, projected increased utilization across our systems and other relevant factors. We remain focused on our long-term goal of positioning to reach net-zero emissions from our operations by 2050 and acknowledge that achieving this goal requires accelerated changes in global energy policies, regulations and support for new technologies.

With the growing demand for energy across our North American footprint and abroad, our team of over 6,500 dedicated energy problem solvers is forging solutions that meet the rising needs of the natural gas and power sectors. To deliver a more resilient energy future, we are operating and expanding critical infrastructure systems that the countries and customers we serve can rely on.

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.

VALUES

Through collaboration with employees and leadership, we've renewed our values to reflect the core behaviours that will drive our success and shape our culture moving forward.

- **SAFETY IN EVERY STEP.**
- **PERSONAL ACCOUNTABILITY.**
- **ONE TEAM.**
- **ACTIVE LEARNING.**

A FOCUSED NATURAL GAS AND POWER COMPANY

A MESSAGE FROM JOHN AND FRANÇOIS

2024 marked a transformational year in TC Energy's history. Through our unwavering commitment to safely and reliably deliver energy, we achieved significant milestones to meet the growing needs of North America and the world. The evolving energy landscape continues to create opportunities, and TC Energy is uniquely positioned to seize them as we step into the future as **a focused natural gas and power and energy solutions company**.

SOLID EXECUTION AND FOCUSED PRIORITIES

In 2024, we set our collective focus on a clear set of strategic priorities:

- **maximizing the value of our assets through safety and operational excellence**
- **executing projects on time and on budget**
- **enhancing the strength and flexibility of our balance sheet.**

With relentless focus, we delivered on these priorities, setting the stage for continued growth and success. Most notably, we completed the successful spinoff of our Liquids Pipelines business into a new public company, South Bow Corporation, advanced the Southeast Gateway pipeline project in Mexico on time and under budget, reached commercial in-service on Coastal GasLink, and achieved significant debt reduction, which aligns with our objective of a long-term target of 4.75 times debt-to-EBITDA[3] ratio. These achievements reflect our ability to adapt, innovate and remain steadfast in our commitment to creating long-term value for our shareholders.

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 2024 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, 2022, 2023 and 2024.

John Lowe

François Poirier

SOLID GROWTH. LOW RISK. REPEATABLE PERFORMANCE.

It's clear the world needs more of all forms of energy to meet ever-growing demand, and we are at the forefront of enabling this growth. The demand for North America's natural gas and power is accelerating, driven by rapid global electrification, the growth of LNG exports, the transition from coal to lower-emitting, reliable energy and technological advancements, including the expansion of data centres.

With an unparalleled footprint spanning Canada, the U.S. and Mexico, TC Energy is uniquely positioned to meet this surging demand.

Our portfolio of natural gas and power assets, approximately 93,700 kilometres of pipelines and investment in nuclear through Bruce Power—anchor our ability to deliver energy securely, affordably and sustainably. Moving forward, we remain focused on executing our 2025 strategic priorities:

- **maximizing the value of our assets through safety and operational excellence**
- **executing our selective portfolio of growth projects**
- **ensuring financial strength and agility.**

OUR TIME IS NOW

Our priorities for 2025 are clear and build upon our 2024 execution excellence. These efforts, combined with our unmatched positions in North American energy infrastructure, reinforce our ability to offer solutions to the energy trilemma.

Our success in 2024 would not have been possible without the dedication and hard work of our skilled team. They consistently work to safely and efficiently move, generate and store the critical energy that North America and the world rely on daily, with the utmost responsibility and care for the communities in which we operate, while being responsive to Indigenous rights holders and stakeholders. Leading these efforts is an unparalleled and talented workforce whose diverse skills, determination and innovative thinking set TC Energy apart.

Our commitment to all stakeholders is bolstered by the governance and oversight of our esteemed Board of Directors, who uphold strong principles and help guide our strategic direction. This year, we were pleased to announce the appointment of two new independent directors, Scott Bonham and Dawn Madahbee Leach, to the Board of Directors. Both bring extensive experience and proven leadership and are poised to contribute to the stewardship of TC Energy's strategic vision and long-term growth. At our upcoming Annual Meeting of Shareholders, Indira Samarasekera and David MacNaughton are retiring from the Board of Directors. Dr. Samarasekera and Mr. MacNaughton have been valuable and committed members of the Board since 2016 and 2020, respectively. We thank them both for their many years of dedicated service to TC Energy and our shareholders.

On behalf of the Board of Directors and our employees, I would like to express our gratitude to you, our shareholders, for your continued trust and investment in TC Energy. Together, we are building a stronger, more resilient future for our company, our communities and the energy sector.

Sincerely,

John Lowe
Chair of the Board of Directors

François Poirier
President and Chief Executive Officer

A FOCUSED SET OF CLEAR PRIORITIES

DELIVERING ON OUR 2024 PRIORITIES

Maximized the value of our assets through safety and operational excellence

- Completed the spinoff of the Liquids Pipelines business and integration of Natural Gas Pipelines business
- Ensured safety, reliability and availability across our portfolio of assets
- Enhanced comparable EBITDA via NGTL five-year negotiated revenue requirement settlement.

Projects executed on time and on budget

- Southeast Gateway achieved mechanical completion ~13 per cent under budget, to US$3.9 billion; aligned with CFE to achieve a May 1, 2025 in-service date
- Bruce Power Unit 3 MCR tracking on cost and schedule; Unit 4 MCR commenced January 31, 2025
- Placed ~$7 billion[4] of assets into service in 2024; on track for ~$8.5 billion in 2025.

Enhanced balance sheet strength and flexibility

- Realized and identified ~$2.5 billion in total cost savings in 2024 – 2027E
- Comparable EBITDA in the upper end or above outlook for the last three years
- Achieved 4.8x debt-to-EBITDA at year-end 2024, a 0.3x decrease vs. year-end 2023.

4 Includes TC Energy's share of equity contributions related to the Coastal GasLink pipeline.

2025 STRATEGIC PRIORITIES

Maximize the value of our assets through safety and operational excellence

- Promote safe operating practices to exceed safety targets and maximize the availability of assets
- Continue advancement of an integrated Natural Gas Pipelines business to capture synergies
- Capture additional value through capital and operational efficiencies.

Execute our selective portfolio of growth projects

- Execute high quality secured capital program and bring ~$8.5 billion of assets into service
  - Including US$3.9 billion for Southeast Gateway
- Deliver 2025E comparable EBITDA of $10.7 – $10.9 billion[5].

Ensure financial strength and agility

- Prioritize low risk, executable projects that maximize the spread between earned return and cost of capital
- Maintain commitment to annual net capital expenditures[6] of $6 – $7 billion
- Continue deleveraging efforts towards our upper limit of 4.75x debt-to-EBITDA.

OUR COMMITMENT

Solid growth. Low risk. Repeatable performance.

- Building on decades of comparable EBITDA and dividend growth
- Ensuring high-quality cash flows underpinned by rate-regulation and/or long-term take-or-pay contracts with little to no price or volumetric risk
- Continuing to demonstrate the agility necessary to evolve to market dynamics and technology shifts in order to deliver solid growth with low-risk repeatability, as we have showcased for over 20 years.

5 Reflects USD/CAD foreign exchange rate of 1.35.

6 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 2024 Annual MD&A (incorporated by reference) for more information about the non-GAAP measures we use. Our 2024 Annual MD&A is available under TC Energy's profile on SEDAR+ at www.sedarplus.ca.

A FOCUSED NATURAL GAS AND POWER COMPANY

NATURAL GAS—UNIQUE AMONG OUR PEERS

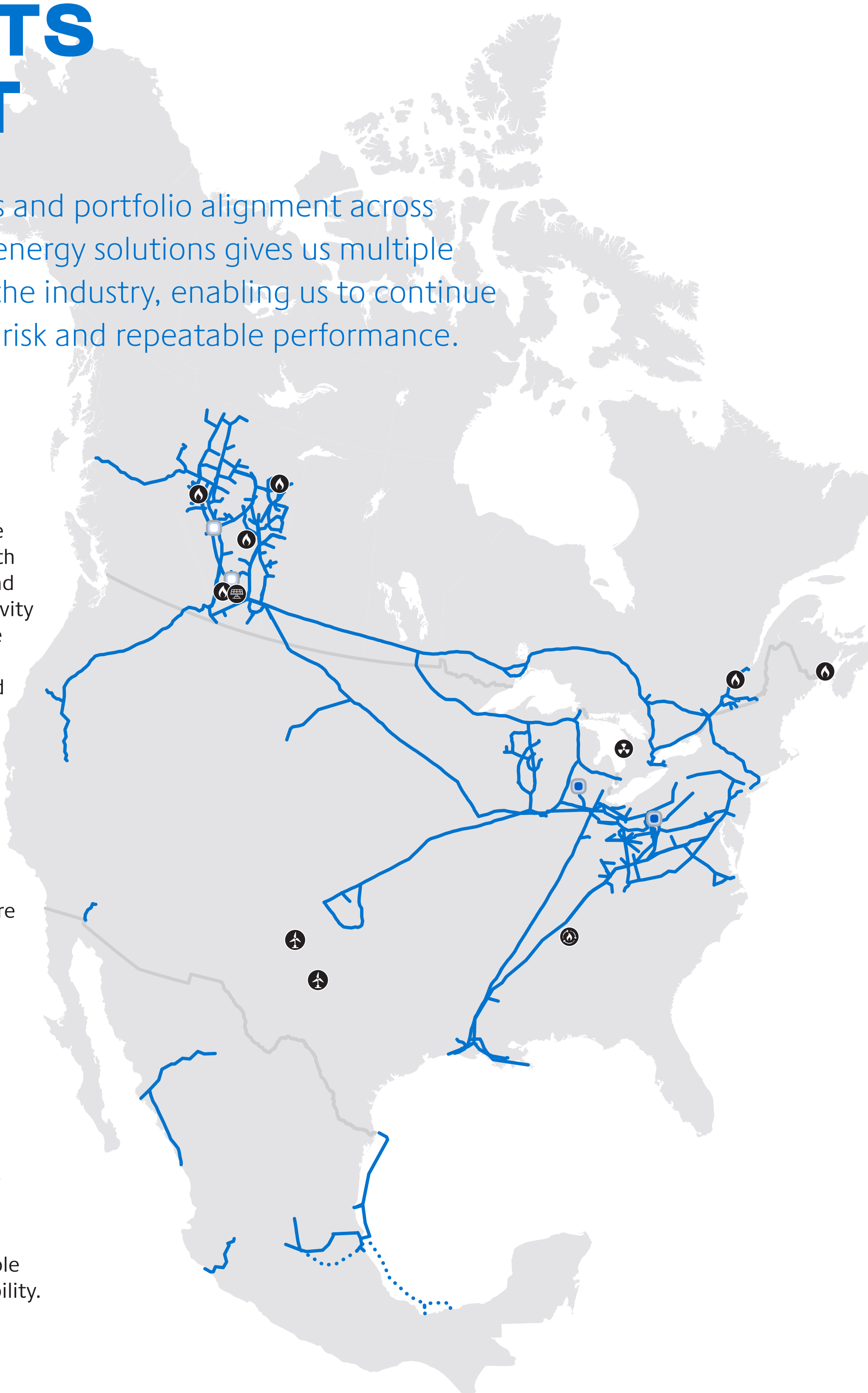
With extensive operations in three geographies across North America, we're leaders in natural gas transportation and storage, with a proud history. With visible and attractive growth through to the end of the decade, our approximately 93,700-kilometre (58,200-mile) strategic network connects the most competitive, low-cost natural gas basins to premium value markets in Canada, the U.S. and Mexico. We safely transport over 30 per cent of the natural gas required to meet energy demand across the continent every day. Our infrastructure provides key connectivity to supply and demand centres and solidifies the foundation to bring natural gas to LNG export terminals in North America. In Canada, we completed construction of the Coastal GasLink pipeline, enabling the first direct path between Canada and global LNG markets to deliver responsibly produced natural gas to the world. In the U.S., our natural gas system currently moves approximately 30 per cent of the feed-gas destined for LNG export. In Mexico, to meet the country's growing demand, we are aligned with the Comisión Federal de Electricidad (CFE) to achieve a May 1, 2025 in-service date on our Southeast Gateway Project. This dedicated pipeline with state-of-the-art technology for transportation is a nation-building initiative that will bring natural gas access to people in southeast Mexico.

POWER AND ENERGY SOLUTIONS —ANCHORED BY NUCLEAR POWER GENERATION

Our power business continues to supply reliable, affordable and sustainable energy. With a portfolio of owned and operated assets, we generate approximately 4,650 megawatts of power-generation capacity, over 75 per cent of which is low carbon emission electricity from nuclear and renewable power sources. Anchored by our 48.3 per cent ownership in Bruce Power, nuclear is the core of our Power and Energy Solutions business and is a critical and complementary part of our TC Energy strategy, with growth visibility through 2030 and beyond with our Major Component Replacement (MCR) program and Project 2030. In Canada, Bruce Power's safe, reliable, affordable and non-emitting power generation plays a critical role in meeting Ontario's growing electricity demand and decarbonization goals, generating approximately 30 per cent of the province's electricity needs. We're focused on maximizing the value of our natural gas generation and storage assets that support the growing demand for reliable and affordable electricity. Keeping focus on the evolving energy mix, we are developing capabilities and expertise in lower-carbon solutions to perpetuate the value of our existing natural gas infrastructure, ensuring we are well-prepared to respond to market shifts and deliver repeatable performance.

WHAT SETS US APART

Our renewed strategic focus and portfolio alignment across natural gas and power and energy solutions gives us multiple competitive advantages in the industry, enabling us to continue achieving solid growth, low risk and repeatable performance.



UNRIVALLED GEOGRAPHICAL DIVERSIFICATION

We are the only natural gas infrastructure company with critical assets in three North American countries—Canada, the U.S. and Mexico. This unique continental connectivity enables us to deliver natural gas from the most competitive, low-cost natural gas basins to critical demand markets beyond borders and continents.

UNWAVERING FOCUS ON NATURAL GAS

We are anchored as North America's dominant natural gas-focused energy transmission and storage company. We are well-positioned for growth to strengthen our natural gas business and keep pace with technological advancements.

COMPLEMENTARY POSITIONS IN POWER

We have a strategic position in power generation with our stake in nuclear—a steady, reliable and emission-less form of energy. This, along with our expertise in gas-fired power generation and natural gas storage, positions us to provide reliable energy supply and contribute to grid stability.

Management's discussion and analysis

February 13, 2025

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, 2024.

This MD&A should also be read in conjunction with our December 31, 2024 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 138. All information is as of February 13, 2025 and all amounts are in Canadian dollars, unless noted otherwise.

On July 27, 2023, TC Energy announced plans to separate into two independent, investment-grade, publicly listed companies through the spinoff of its Liquids Pipelines business. TC Energy shareholders voted to approve the spinoff in June 2024 and, 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. Prior year results have been recast to reflect the split between continuing and discontinued operations. Discontinued operations reflect nine months of Liquids Pipelines earnings for the year ended December 31, 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022. Refer to Note 4, Discontinued operations, of our 2024 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 and GHG Emissions Reduction Plan, including statements related to our GHG emissions intensity reduction goals
- 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 benefits from acquisitions and divestitures, including the Spinoff Transaction
- 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 benefits from acquisitions and divestitures, including the Spinoff Transaction
- our ability to successfully implement our strategic priorities, including the Focus Project, 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.

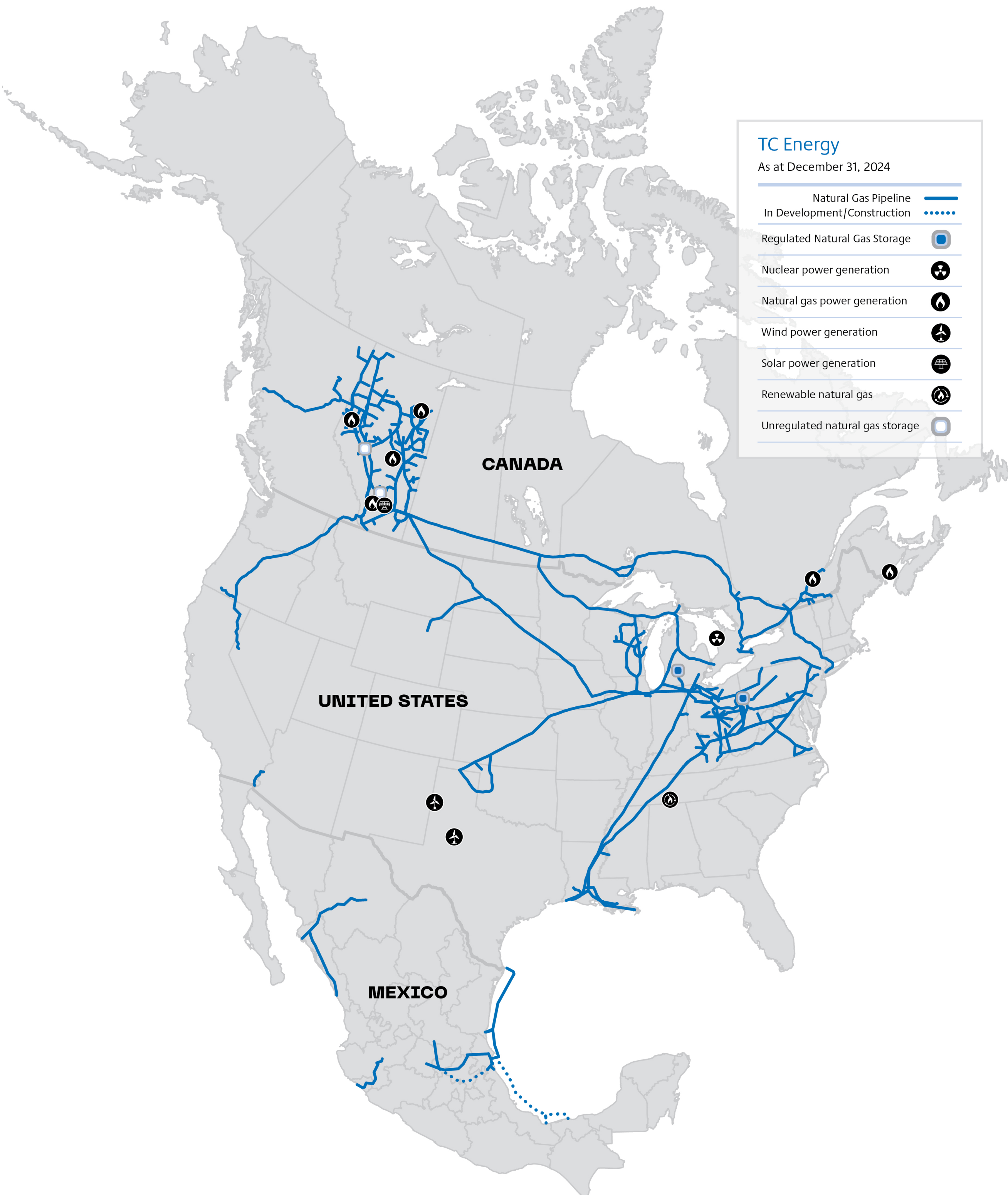
As actual results could vary significantly from the forward-looking information, you should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements 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 94 for additional information.

Year at-a-glance

at December 31 (millions of $)	2024	2023[1]
Total assets by segment		
Canadian Natural Gas Pipelines	**31,167**	29,782
U.S. Natural Gas Pipelines	**56,304**	50,499
Mexico Natural Gas Pipelines	**15,995**	12,003
Power and Energy Solutions	**10,217**	9,525
Corporate	**4,189**	7,715
	117,872	109,524
Discontinued Operations	**371**	15,510
	118,243	125,034

1 Prior year results have been recast to reflect the split between continuing and discontinued operations.

year ended December 31 (millions of $)	2024	2023
Total revenues from continuing operations by segment[1]		
Canadian Natural Gas Pipelines	**5,600**	5,173
U.S. Natural Gas Pipelines	**6,339**	6,229
Mexico Natural Gas Pipelines	**870**	846
Power and Energy Solutions	**954**	1,019
Corporate	**8**	—
	13,771	13,267

1 Excludes revenues of $2,217 million and $2,667 million for the years ended December 31, 2024 and 2023, respectively, related to discontinued operations, which represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023.

year ended December 31 (millions of $)	2024	2023
Comparable EBITDA from continuing operations by segment[1,2]		
Canadian Natural Gas Pipelines	**3,388**	3,335
U.S. Natural Gas Pipelines	**4,511**	4,385
Mexico Natural Gas Pipelines	**999**	805
Power and Energy Solutions	**1,214**	1,020
Corporate	**(63)**	(73)
	10,049	9,472

1 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.

2 Excludes Comparable EBITDA from discontinued operations of $1,145 million and $1,516 million for the years ended December 31, 2024 and 2023, respectively, which represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023. For further information on the reconciliation of segmented earnings to comparable EBITDA, refer to the Financial results sections for each business segment and the Discontinued operations section.

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. We are a team of energy problem solvers working to deliver energy in a safe, reliable, secure and affordable manner, while seeking to uphold 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	2024	2023[2]
Comparable EBITDA from continuing operations by segment[3]		
Canadian Natural Gas Pipelines	**33%**	35%
U.S. Natural Gas Pipelines	**45%**	46%
Mexico Natural Gas Pipelines	**10%**	8%
Power and Energy Solutions	**12%**	11%
	100%	100%

1 Refer to the Financial highlights section for an allocation of segmented earnings by business segment.
2 Prior year results have been recast to reflect continuing operations only.
3 Excludes losses from Corporate comparable EBITDA from continuing operations of $63 million and $73 million for the years ended December 31, 2024 and 2023, 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 core businesses, 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 availability of assets and ensuring asset integrity, while minimizing environmental impacts, continues to be the foundation of our business
- Our extensive network of natural gas pipeline assets connect long-life, low-cost supply basins with premium North American and export markets, which we believe will generate predictable and sustainable cash flows and earnings
- Our power and non-regulated storage assets are primarily under long-term contracts that provide stable cash flows and earnings
- We continually seek to enhance and protect the value of each of our assets using operational, commercial and other levers while pursuing revenue enhancements such as creating additional capacity in our systems and leveraging commercial marketing activities.

Execute our selective portfolio of growth projects

- Safety, executability, profitability and reliability are fundamental to our investments
- We develop high quality, long-life assets, largely underpinned by long-term contracts or rate regulation. We expect that these investments will contribute to incremental earnings and cash flows as they are placed in service
- We believe that our incumbent positions in regions with natural gas and power demand growth are expected to present us with a steady cadence of growth opportunities
- We strive to develop projects and manage construction risk in a disciplined manner that maximizes capital efficiency and returns to shareholders
- We seek to prudently manage development costs, minimizing capital at risk in a project's early stages
- We rely on our experience, as well as our policy, regulatory, commercial, financial, legal and operational expertise to permit, fund, build and integrate new pipelines and other energy infrastructure
- We will advance selected opportunities, including lower carbon growth initiatives, in emerging sub-sectors where we are likely to build a strong competitive position, market conditions are appropriate, technology is proven and project risks and returns are known and acceptable.

Ensure financial strength and agility

- Disciplined capital allocation supports our ability to maximize asset value over the short, medium and long term while protecting and growing our network of assets. We seek to allocate capital in a manner that improves the cost competitiveness and returns of our portfolio, while extending the life of our assets
- Our capital allocation process is designed to ensure that we remain within the annual target for net capital spend, while maximizing the expected returns of the projects that we sanction
- We assess opportunities to develop and acquire energy infrastructure that complements our existing portfolio, protects and grows our business, enhances future resilience under a changing energy mix and diversifies access to attractive supply and market regions within our risk preferences
- We monitor trends specific to energy supply and demand fundamentals, in addition to analyzing how our portfolio performs under different energy mix scenarios. This enables the identification of opportunities that we believe will contribute to our resilience, strengthen our asset base and/or improve diversification
- We believe that our high-quality, diversified portfolio of energy infrastructure assets results in predictable, low-risk cash flows and positions us well to succeed under various energy transition scenarios and across all economic cycles
- We continually seek to enhance our core competencies in safety, operational excellence, investment opportunity origination, project execution, stakeholder relations and sustainability to ensure we deliver shareholder value.

How we operate our business

The need for safe, reliable, secure and affordable energy solutions has become increasingly important. Decades of experience in the energy infrastructure business, a disciplined approach to project management and a proven capital allocation model result in a solid competitive position as we remain focused on our purpose – to connect the world to the energy it needs. We will do this through:

- **strong leadership and governance:** we maintain rigorous governance over our approach to business ethics, enterprise risk management, competitive behaviour, operating capabilities and strategy development, as well as regulatory, legal, commercial, stakeholder and financing support
- **a high-quality portfolio:** the strategic advantage supporting our vision is our extensive asset footprint in an industry with high barriers to entry. Our low-risk portfolio of assets offers the scale to provide essential and highly competitive infrastructure services, enabling us to maximize the full-life value of our investments throughout all points of the business cycle. Our platforms not only provide a diversified portfolio but also position TC Energy as a leader in the energy infrastructure sector. Our synergistic footprint supports both molecules and electrons, providing us flexibility to allocate capital towards natural gas, electrification or other emerging lower-carbon technologies that are complementary to our core businesses
- **disciplined operations:** our workforce is highly skilled in designing, building and operating energy infrastructure with a focus on safety and operational excellence and a commitment to the environment in the communities we serve that is suited to both today's environment, as well as an evolving energy industry
- **financial positioning:** we exhibit consistently strong financial performance, long-term stability and profitability, along with a disciplined approach to capital investment. We can access competitively-priced capital to support new investments while preserving financial flexibility, including portfolio management, to fund our operations in all market conditions. We aim to deliver a balance of dividend income and share price growth
- **proven ability to adapt:** we have a long track record of turning policy and technology changes into opportunities – for example, re-entering Mexico when the country shifted from fuel oil to natural gas, reversing pipeline flows in response to the shale gas revolution, installing electric compression and/or switching gas compression to electrification and currently assessing development of grid-scale, flexible and clean energy storage
- **commitment to sustainability:** we take a long-term view to managing our interactions with the environment, Indigenous groups, community members and landowners. We aim to communicate transparently to all rights holders and stakeholders on sustainability-related topics and publish annually our corporate GHG emissions intensity in our Report on Sustainability. We continue to focus on our sustainability commitments, which reflect the interests of our business, Indigenous rights holders and stakeholders; positioning us for long-term success. We are committed to collectively advancing a lower-emissions energy system and expect to provide an update on our interim GHG emission reduction target in 2025 to reflect the impact of the Liquids Pipelines business spinoff and projected increased utilization across our systems. We remain focused on our long-term goal of positioning to reach net-zero emissions from our operations by 2050 and acknowledge that achieving this goal requires accelerated changes in global energy policies, regulations and support for new technologies. We continue to focus on our nine sustainability commitments and associated metrics and targets that help ensure our business is well positioned for long-term success
- **open communication:** we carefully manage relationships with our customers, suppliers, regulators and other stakeholders and offer clear, candid communication to investors in order to build trust and support
- **culture and people:** our people are our most important asset and living our company values of safety, personal accountability, working as one team and active learning. These values shape how we do business and, in turn, deliver on our commitments.

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 that are investment-grade on a stand-alone basis 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 "top-end" sector ratings:** solid investment-grade ratings are an important competitive advantage and TC Energy will seek to ensure our credit profile remains at the top end of our sector 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.

2024 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 24 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, results of the Liquids Pipelines business are reported as a discontinued operation. To allow for a meaningful comparison, discussions throughout this MD&A are based on continuing operations unless otherwise noted. Prior year results have been recast to reflect the split between continuing and discontinued operations. Discontinued operations reflect nine months of Liquids Pipelines earnings for the year ended December 31, 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022. Refer to the Discontinued operations section for additional information.

year ended December 31 (millions of $, except per share amounts)	**2024**	**2023**[1]	**2022**[1]
Income			
Revenues	**13,771**	13,267	12,309
Net income (loss) attributable to common shares	**4,594**	2,829	641
from continuing operations	4,199	2,217	8
from discontinued operations[2]	395	612	633
Net income (loss) per common share – basic	**$4.43**	$2.75	$0.64
from continuing operations	$4.05	$2.15	$0.01
from discontinued operations[2]	$0.38	$0.60	$0.63
Comparable EBITDA[3]	**11,194**	10,988	9,901
from continuing operations	10,049	9,472	8,483
from discontinued operations[2]	1,145	1,516	1,418
Comparable earnings[3]	**4,430**	4,652	4,279
from continuing operations	3,865	3,896	3,618
from discontinued operations[2]	565	756	661
Comparable earnings per common share[3]	**$4.27**	$4.52	$4.30
from continuing operations	$3.73	$3.78	$3.64
from discontinued operations[2]	$0.54	$0.74	$0.66

1 Prior year results have been recast to reflect the split between continuing and discontinued operations.

2 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022. Refer to the Discontinued operations section for additional information.

3 Additional information on the most directly comparable GAAP measure can be found on page 24.

year ended December 31 (millions of $)	2024	2023	2022
Cash flows[1]			
Net cash provided by operations[2]	**7,696**	7,268	6,375
Comparable funds generated from operations[2,3]	**7,890**	7,980	7,353
Capital spending[4]	**7,904**	12,298	8,961
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 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022. Refer to the Discontinued operations section for additional information.
3 Additional information on the most directly comparable GAAP measure can be found on page 24.
4 Capital spending reflects cash flows associated with our Capital expenditures, Capital projects in development and Contributions to equity investments net of Other distributions from equity investments of $3.1 billion in 2024 in the Canadian Natural Gas Pipelines segment (2023 - nil, 2022 - $1.2 billion in the Corporate segment). Refer to Note 5, Segmented information, Note 7, Coastal GasLink and Note 12, Loans receivable from affiliates, of our 2024 Consolidated financial statements for additional information.
5 Included in the Financing activities section of the Consolidated statement of cash flows, of our 2024 Consolidated financial statements.

at December 31 (unless otherwise noted) (millions of $, except per share amounts)	2024	2023	2022
Balance sheet			
Total assets[1]	**118,243**	125,034	114,348
Long-term debt, including current portion	**47,931**	52,914	41,543
Junior subordinated notes	**11,048**	10,287	10,495
Preferred shares	**2,499**	2,499	2,499
Non-controlling interests	**10,768**	9,455	126
Common shareholders' equity	**25,093**	27,054	31,491
Dividends declared[2]			
per common share[3]	**$3.7025**	$3.72	$3.60
Basic common shares (millions)			
– weighted average for the year ended	**1,038**	1,030	995
– issued and outstanding at end of year	**1,039**	1,037	1,018

1 At December 31, 2024, includes assets of $371 million (2023 - $15,510 million; 2022 - $15,587 million), related to discontinued operations. Refer to Note 4, Discontinued operations, of our 2024 Consolidated financial statements for additional information.
2 For the year ended.
3 Dividends declared in fourth quarter 2024 reflect TC Energy's proportionate allocation following the Spinoff Transaction. Refer to the Discontinued operations section for additional information.

Consolidated results

year ended December 31 (millions of $, except per share amounts)	2024	2023[1]	2022[1]
Canadian Natural Gas Pipelines	**2,016**	(90)	(1,440)
U.S. Natural Gas Pipelines	**4,053**	3,531	2,617
Mexico Natural Gas Pipelines	**929**	796	491
Power and Energy Solutions	**1,102**	1,004	833
Corporate	**(136)**	(144)	(51)
Total segmented earnings (losses)	**7,964**	5,097	2,450
Interest expense	**(3,019)**	(2,966)	(2,300)
Allowance for funds used during construction	**784**	575	369
Foreign exchange gains (losses), net	**(147)**	320	(185)
Interest income and other	**324**	272	140
Income (loss) from continuing operations before income taxes	**5,906**	3,298	474
Income tax (expense) recovery from continuing operations	**(922)**	(842)	(322)
Net income (loss) from continuing operations	**4,984**	2,456	152
Net income (loss) from discontinued operations, net of tax[2]	**395**	612	633
Net income (loss)	**5,379**	3,068	785
Net (income) loss attributable to non-controlling interests	**(681)**	(146)	(37)
Net income (loss) attributable to controlling interests	**4,698**	2,922	748
Preferred share dividends	**(104)**	(93)	(107)
Net income (loss) attributable to common shares	**4,594**	2,829	641
Net income (loss) per common share – basic	**$4.43**	$2.75	$0.64
from continuing operations	**$4.05**	$2.15	$0.01
from discontinued operations[2]	**$0.38**	$0.60	$0.63

1 Prior year results have been recast to reflect the split between continuing and discontinued operations.
2 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022. Refer to the Discontinued operations section for additional information.

year ended December 31 (millions of $)	2024	2023[1]	2022[1]
Amounts attributable to common shares			
Net income (loss) from continuing operations	**4,984**	2,456	152
Net (income) loss attributable to non-controlling interests	**(681)**	(146)	(37)
Net income (loss) attributable to controlling interests from continuing operations	**4,303**	2,310	115
Preferred share dividends	**(104)**	(93)	(107)
Net income (loss) attributable to common shares from continuing operations	**4,199**	2,217	8
Net income (loss) from discontinued operations, net of tax[2]	**395**	612	633
Net income (loss) attributable to common shares	**4,594**	2,829	641

1 Prior year results have been recast to reflect the split between continuing and discontinued operations.
2 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022. Refer to the Discontinued operations section for additional information.

Net income attributable to common shares from continuing operations in 2024 was $4.2 billion or $4.05 per share (2023 – $2.2 billion or $2.15 per share; 2022 – $8 million or $0.01 per share), an increase of $2.0 billion or $1.90 per share compared to 2023 and an increase of $2.2 billion or $2.14 per share in 2023 compared to 2022. 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 $7.7 billion in 2024 was six per cent higher than 2023 primarily due to higher funds generated from continuing operations and the amount and timing of working capital changes. Comparable funds generated from operations of $7.9 billion in 2024 were one per cent lower than 2023 primarily due to lower comparable earnings, partially offset by increased distributions from our equity investments.

Funds used in investing activities

Capital spending[1]

year ended December 31 (millions of $)	2024	2023	2022
Canadian Natural Gas Pipelines	**2,100**	6,184	4,719
U.S. Natural Gas Pipelines	**2,575**	2,660	2,137
Mexico Natural Gas Pipelines	**2,228**	2,292	1,027
Power and Energy Solutions	**824**	1,080	894
Corporate	**50**	33	41
	7,777	12,249	8,818
Discontinued operations	**127**	49	143
	7,904	12,298	8,961

1 Capital spending reflects cash flows associated with our Capital expenditures, Capital projects in development and Contributions to equity investments net of Other distributions from equity investments of $3.1 billion in 2024 in the Canadian Natural Gas Pipelines segment (2023 - nil, 2022 - $1.2 billion in the Corporate segment). Refer to Note 5, Segmented information, Note 7, Coastal GasLink and Note 12, Loans receivable from affiliates, of our 2024 Consolidated financial statements, for additional information.

In 2024 and 2023, we invested $7.9 billion and $12.3 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 2024 and 2023 included contributions of $1.5 billion (net of distributions) and $4.1 billion, respectively, to our equity investments, predominantly related to Coastal GasLink Limited Partnership (Coastal GasLink LP) and Bruce Power.

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 $8.3 billion in 2024. At December 31, 2024, common shareholders' equity and non-controlling interests, represented 37 per cent (2023 – 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 (2023 – 13 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 the Discontinued operations section for additional information.

On February 14, 2025, we announced a quarterly dividend on our outstanding common shares of $0.85 per common share for the quarter ending March 31, 2025, which represents an increase of 3.3 per cent from TC Energy's proportionate allocation of the dividend following the Spinoff Transaction. This equates to an annual dividend of $3.40 per common share. This was the twenty-fifth consecutive year we have increased the dividend on our common shares and is consistent with our goal of growing our common share dividend at an average annual rate of three to five per cent.

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 $)	**2024**	**2023**	**2022**
Common shares	**3,953**	2,787	3,192
Preferred shares	**99**	92	106

NON-GAAP MEASURES

This MD&A references non-GAAP measures, which are described 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 fair value adjustments 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 each of our continuing operations and discontinued operations. Quantitative reconciliations of our comparable measures to their GAAP measures and a discussion of specific adjustments made for 2024 and comparative periods can be found on pages 26 and 27, 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 96.

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 29, Changes in operating working capital, of our 2024 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 27 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:

2024

- a pre-tax gain of $572 million (after-tax $456 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 (after-tax $178 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 (after-tax $153 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 gain of $48 million (after-tax $63 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 (after-tax $15 million) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico, net of non-controlling interest
- 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 (after-tax $27 million) related to development costs incurred on Project Tundra, a next-generation technology carbon capture and storage project, following our decision to end our collaboration on the project
- a pre-tax expense of $34 million (after-tax $26 million) related to a non-recurring third-party settlement
- a pre-tax expense of $24 million (after-tax $18 million) related to Focus Project costs
- pre-tax costs of $10 million (after-tax $42 million) related to the NGTL System Ownership Transfer.

2023

- a pre-tax impairment charge of $2.1 billion (after-tax $1.9 billion) related to our equity investment in Coastal GasLink LP. Refer to Note 7, Coastal GasLink, of our 2024 Consolidated financial statements for additional information
- a pre-tax expense of $65 million (after-tax $48 million) related to Focus Project costs
- pre-tax unrealized foreign exchange losses, net, of $44 million (after-tax $44 million) on the peso-denominated intercompany loan between TCPL and TGNH
- a pre-tax recovery of $80 million (after-tax $55 million) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico.

2022

- a pre-tax impairment charge of $3.0 billion (after-tax $2.6 billion) related to our equity investment in Coastal GasLink LP
- a pre-tax goodwill impairment charge of $571 million (after-tax $531 million) related to Great Lakes
- a $196 million expense related to the settlement of prior years' income tax assessments related to our operations in Mexico
- a pre-tax expected credit loss provision of $163 million (after-tax $114 million) 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)	2024	2023[1]	2022[1]
Net income (loss) attributable to common shares from continuing operations	**4,199**	2,217	8
Specific items (pre tax):			
Gain on sale of PNGTS	**(572)**	—	—
Net gain on debt extinguishment[2]	**(228)**	—	—
Foreign exchange (gains) losses, net – intercompany loan[3]	**(143)**	44	—
Gain on sale of non-core assets	**(48)**	—	—
Expected credit loss provision on net investment in leases and certain contract assets in Mexico[4]	**(22)**	(80)	163
Project Tundra impairment charge	**36**	—	—
Third-party settlement	**34**	—	—
Focus Project costs[5]	**24**	65	—
NGTL System ownership transfer costs	**10**	—	—
Coastal GasLink impairment charge	**—**	2,100	3,048
Great Lakes goodwill impairment charge	**—**	—	571
Bruce Power unrealized fair value adjustments	**(8)**	(7)	17
Risk management activities[6]	**433**	(395)	149
Taxes on specific items[7]	**150**	(48)	(338)
Comparable earnings from continuing operations	**3,865**	3,896	3,618
Net income (loss) per common share from continuing operations	**$4.05**	$2.15	$0.01
Specific items (net of tax)	**(0.32)**	1.63	3.63
Comparable earnings per common share from continuing operations	**$3.73**	$3.78	$3.64

1 Prior year results have been recast to reflect continuing operations only.

2 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 the Financial condition section for additional information.

3 In 2023, TCPL and TGNH became party to an unsecured revolving credit facility. The loan receivable and loan payable are eliminated upon consolidation; however, due to differences in the currency that each entity reports its financial results, there is an impact to net income reflecting the revaluation and translation of the loan receivable and loan payable to TC Energy's reporting currency. As the amounts do not accurately reflect what will be realized at settlement, we exclude from comparable measures the unrealized foreign exchange gains and losses on the loan receivable, as well as the corresponding unrealized foreign exchange gains and losses on the loan payable, net of non-controlling interest.

4 In 2022, TGNH and the CFE executed agreements which consolidate several natural gas pipelines under one TSA. As this TSA contains a lease, we have recognized amounts in net investment in leases on our Consolidated balance sheet. As required by U.S. GAAP, 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 28, Risk management and financial instruments, of our 2024 Consolidated financial statements for additional information.

5 In 2022, we launched the Focus Project with benefits in the form of enhanced safety, productivity and cost-effectiveness expected to be realized in the future. Beginning in 2023, we recognized expenses in Plant operating costs and other, for external consulting and severance, some of which are not recoverable through regulatory and commercial tolling structures. Refer to the Corporate – Significant events section for additional information.

6 year ended December 31			
(millions of $)	**2024**	**2023**	**2022**
U.S. Natural Gas Pipelines	**(113)**	80	(15)
Canadian Power	**84**	(31)	4
U.S. Power	**(10)**	9	—
Natural Gas Storage	**(57)**	91	11
Interest rate	**(71)**	—	—
Foreign exchange	**(266)**	246	(149)
	(433)	395	(149)
Income tax attributable to risk management activities	**105**	(99)	36
Total unrealized gains (losses) from risk management activities	**(328)**	296	(113)

7 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)	**2024**	**2023**[1]	**2022**[1]
Comparable EBITDA from continuing operations			
Canadian Natural Gas Pipelines	**3,388**	3,335	2,806
U.S. Natural Gas Pipelines	**4,511**	4,385	4,089
Mexico Natural Gas Pipelines	**999**	805	753
Power and Energy Solutions	**1,214**	1,020	907
Corporate	**(63)**	(73)	(72)
Comparable EBITDA from continuing operations	**10,049**	9,472	8,483
Depreciation and amortization	**(2,535)**	(2,446)	(2,262)
Interest expense included in comparable earnings	**(3,176)**	(2,966)	(2,300)
Allowance for funds used during construction	**784**	575	369
Foreign exchange gains (losses), net included in comparable earnings	**(85)**	118	(8)
Interest income and other	**324**	272	140
Income tax (expense) recovery included in comparable earnings	**(772)**	(890)	(660)
Net (income) loss attributable to non-controlling interests included in comparable earnings	**(620)**	(146)	(37)
Preferred share dividends	**(104)**	(93)	(107)
Comparable earnings from continuing operations	**3,865**	3,896	3,618
Comparable earnings per common share from continuing operations	**$3.73**	$3.78	$3.64

1 Prior year results have been recast to reflect continuing operations only.

Comparable EBITDA from continuing operations

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 79, 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.

2023 versus 2022

Comparable EBITDA from continuing operations in 2023 increased by $989 million compared to 2022 primarily due to the net result of the following:

- increased EBITDA from Canadian Natural Gas Pipelines primarily due to higher flow-through costs and increased rate-base earnings on the NGTL System and higher earnings from Coastal GasLink related to the recognition of a $200 million incentive payment upon meeting certain milestones
- increased Power and Energy Solutions EBITDA primarily attributable to higher contributions from Bruce Power as a result of a higher contract price, fewer planned outage days and lower depreciation expense, partially offset by increased business development activities across the segment
- higher U.S. dollar-denominated EBITDA from U.S. Natural Gas Pipelines due to incremental earnings from growth projects placed in service, a net increase in earnings from ANR resulting from an increase in transportation rates effective August 2022, higher realized margins related to our U.S. natural gas marketing business, partially offset by higher operational costs reflective of increased system utilization and lower commodity prices related to our mineral rights business
- higher U.S. dollar-denominated EBITDA from Mexico Natural Gas Pipelines primarily related to certain sections of the Villa de Reyes and Tula pipelines that were placed in commercial service in third quarter 2022 and 2023, partially offset by lower equity earnings from Sur de Texas primarily due to peso-denominated financial exposure and higher interest expense
- 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 79,U.S. dollar-denominated comparable EBITDA from continuing operations increased by US$100 million compared to 2022, which was translated to Canadian dollars at an average rate of 1.35 in 2023 versus 1.30 in 2022. 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

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 Transmission, LLC (Columbia Gas) and Columbia Gulf Transmission, LLC (Columbia Gulf) in fourth quarter 2023 and the 13.01 per cent non-controlling equity interest in TGNH to the CFE, completed in second quarter 2024.

2023 versus 2022

Comparable earnings from continuing operations in 2023 were $278 million or $0.14 per common share higher than in 2022, 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 and the acquisition of the Texas Wind Farms, partially offset by the discontinuance of depreciation expense on TGNH assets in Mexico accounted for as leases
- higher interest expense primarily due to long-term debt issuances, net of maturities, the foreign exchange impact of a stronger U.S. dollar in 2023 compared to 2022 and higher interest rates on our long-term debt
- higher AFUDC predominantly due to the Southeast Gateway pipeline project, as well as the reactivation of AFUDC on the TGNH assets under construction, partially offset by projects placed in service
- 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
- increased income tax expense due to the impact of higher comparable earnings subject to income tax, Mexico foreign exchange exposure and lower foreign income tax rate differentials, partially offset by lower flow-through income taxes and lower Mexico inflation adjustments
- 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 and the acquisition of the Texas Wind Farms.

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, including Villa de Reyes, Southeast Gateway and Tula. 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 - continuing operations

We expect our 2025 comparable EBITDA to be higher than 2024 comparable EBITDA due to the net impact of the following:

- new projects anticipated to be placed in service in 2025, including the Southeast Gateway pipeline, along with the full-year impact of projects placed in service in 2024
- higher contributions from the NGTL System resulting from the five-year negotiated revenue requirement settlement
- reduced generation from Bruce Power due to the commencement of the Unit 4 Major Component Replacement (MCR) outage.

Our 2025 comparable earnings per common share is expected to be lower than 2024 comparable earnings per common share considering the net impact of the following:

- increase in comparable EBITDA described above
- lower AFUDC due to the Southeast Gateway pipeline expected to be placed in service on May 1, 2025
- lower interest income as a result of lower cash balances and lower interest rates
- increased depreciation rates on the NGTL System related to the five-year negotiated revenue requirement settlement
- reduced capitalized interest due to the Coastal GasLink pipeline commercial in-service
- higher effective tax rates.

Consolidated capital expenditures

In 2024, we incurred approximately $8.2 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 was $7.4 billion.

The majority of our 2025 capital program is focused on the advancement of secured projects including U.S. Natural Gas Pipelines projects, NGTL System expansions, the Southeast Gateway pipeline, Bruce Power MCR programs and normal course maintenance capital expenditures. Prior to adjustments for non-controlling interests, we expect to incur gross capital expenditures of approximately $6.1 to $6.6 billion in 2025. We anticipate our net capital expenditures in 2025 to be approximately $5.5 to $6.0 billion.

Refer to the Outlook section in each business segment for additional details on expected earnings and capital expenditures for 2025.

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 $25 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 2024, we placed approximately $6.8 billion of projects into service, which included natural gas pipeline capacity projects along our extensive North American asset footprint and our share of equity contributions related to the Coastal GasLink pipeline, as well as progress on the Bruce Power life extension program. In addition, approximately $2.3 billion of maintenance capital expenditures were incurred and $0.3 billion of modernization capital expenditures were placed in service.

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 $)	Expected in-service date	Estimated project cost	Project costs incurred at December 31, 2024
Canadian Natural Gas Pipelines[1]			
NGTL System	2026	0.7 [2]	0.2
	2027+	0.2 [2]	—
Regulated maintenance capital expenditures	2025-2027	2.5	—
U.S. Natural Gas Pipelines			
VR project	2025	US 0.5	US 0.3
WR project	2025	US 0.7	US 0.3
Heartland project	2027	US 0.9	US 0.1
Pulaski and Maysville projects	2029	US 0.7	—
Gillis Access – Extension	2026-2027	US 0.4	US 0.1
Southeast Virginia Energy Storage project	2030	US 0.3	—
Other capital	2025-2028	US 1.5	US 0.4
Regulated maintenance capital expenditures	2025-2027	US 2.3	—
Mexico Natural Gas Pipelines			
Villa de Reyes – South section[3]	—	US 0.4	US 0.3
Tula[4]	—	US 0.4	US 0.3
Southeast Gateway	2025	US 3.9	US 3.7
Power and Energy Solutions			
Bruce Power – Unit 3 MCR	2026	1.1	0.9
Bruce Power – Unit 4 MCR	2028	0.9	0.2
Bruce Power – life extension[5]	2025-2031	1.8	0.6
Other			
Non-recoverable maintenance capital expenditures[6]	2025-2027	0.4	—
		19.6	7.4
Foreign exchange impact on secured projects[7]		5.3	2.4
Total secured projects (Cdn$)		24.9	9.8

1 Our share of committed equity to fund the estimated cost of the Coastal GasLink - Cedar Link project is $37 million. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information.
2 Includes amounts related to projects within the Multi-Year Growth Plan (MYGP) that have received FID.
3 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. Refer to the Mexico Natural Gas Pipelines – Significant events section for additional information.
4 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. Refer to the Mexico Natural Gas Pipelines – Significant events section for additional information.
5 Reflects amounts to be invested under the Asset Management program, other life extension projects and the incremental uprate initiative. Refer to the Power and Energy Solutions – Significant events section for additional information.
6 Includes non-recoverable maintenance capital expenditures from all segments and is primarily related to our Power and Energy Solutions and Corporate assets.
7 Reflects U.S./Canada foreign exchange rate of 1.44 at December 31, 2024.

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 corporate 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 targeted in-service dates between 2027 and 2030 that are subject to final corporate 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, reduce GHG emissions intensity 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 supply natural gas through our existing utility customer base or by way of direct connections. Additional opportunities include RNG through direct interconnects, 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 5, 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 5, 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.

The Unit 5 MCR final cost and schedule estimate was submitted to the IESO on January 31, 2025.

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.

Alberta Carbon Grid

In June 2021, we announced a partnership with Pembina Pipeline Corporation to jointly develop a world-scale system which, when fully constructed, is expected to be capable of transporting and sequestering more than 20 million tonnes of CO_2 annually. As an open-access system, the Alberta Carbon Grid (ACG) is intended to serve as the backbone for Alberta's emerging carbon capture utilization and storage industry. In October 2022, ACG entered into a carbon sequestration evaluation agreement with the Government of Alberta to further evaluate one of the largest Areas of Interest (AOI) for safely storing carbon from industrial emissions in Alberta. ACG continues to progress an appraisal program needed to evaluate the suitability of our AOI, including the advancement and completion of well drilling and testing activities to support the development of a detailed Measurement, Monitoring and Verification plan required to apply for a sequestration permit. We are continuing to advance discussions on a commercial agreement with customers that aligns with our risk preferences.

Other Energy Solutions Projects

Our focus in Energy Solutions includes piloting new technologies like hydrogen and carbon capture for our natural gas business, continued partnerships and investments in emerging technologies and the selective development of decarbonization solutions for customers, allowing us to stay ahead of technological adoption trends. If successful, these technologies are expected to enable us to build capabilities that will allow us to reduce the emissions intensity from our existing assets, which will help enhance and preserve the value of our natural gas networks while also capitalizing on lower-carbon investment opportunities that are underpinned by commercial models that meet our risk preferences.

NATURAL GAS PIPELINES BUSINESS

Our natural gas pipeline network transports natural gas from supply basins to local distribution companies, 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 – 63,322 km (39,345 miles)
- partially-owned natural gas pipelines – 30,365 km (18,868 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 ESG considerations into our decision making around new projects, modernization, maintenance, electrification and enhanced leak detection. Further, a growing number of RNG customers are connecting to our system. Our business model provides socioeconomic benefits as we work closely with Indigenous communities, community-based organizations, landowners, rights holders and other stakeholders in alignment with our values and sustainability commitments.

Recent highlights

Canadian Natural Gas Pipelines

- approximately $0.6 billion of capacity capital projects related to the NGTL System were placed into service in 2024
- Coastal GasLink pipeline was declared commercially in service in fourth quarter 2024
- Coastal GasLink LP approved the Cedar Link project in second quarter 2024
- construction activities commenced on the Valhalla North and Berland River (VNBR) project in fourth quarter 2024
- received Board of Directors' approval to allocate approximately $3.3 billion of capital towards the MYGP for expansion facilities on the NGTL System, subject to final company and regulatory approvals
- achieved record throughput volumes on the NGTL System
- continued strong throughput and contracting on Canadian Mainline
- CER approved a five-year negotiated settlement on the NGTL System (2025-2029 NGTL Settlement).

U.S. Natural Gas Pipelines

- placed approximately US$1.9 billion of capital projects in service in 2024, including the Gillis Access project, Virginia Electrification and GTN XPress projects as well as completion of the Columbia Gas Modernization III program and maintenance capital
- sanctioned US$1.5 billion of capital projects including the Maysville and Pulaski projects on Columbia Gulf, Southeast Virginia Energy Storage project on Columbia Gas and the extension of Gillis Access
- Columbia Gas filed a Section 4 Rate Case with FERC in September 2024 requesting an increase to maximum transportation rates effective April 1, 2025, subject to refund. The rate case is progressing as expected as we continue to pursue a collaborative process through settlement negotiations
- the sale of our 61.7 per cent equity interest in PNGTS was completed on August 15, 2024
- achieved record throughput volumes on a number of our pipelines.

Mexico Natural Gas Pipelines

- the Southeast Gateway pipeline project is progressing according to planned milestones and we continue to be aligned with the CFE on finalizing the remaining project completion activities for achieving an in-service date of May 1, 2025
- the CFE became a partner in TGNH with a 13.01 per cent equity interest in second quarter 2024
- 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.

Our major pipeline systems

The Natural Gas Pipelines map on page 41 shows our extensive pipeline network in North America that connects major supply sources and markets. The highlights shown on the map include:

Canadian Natural Gas Pipelines

NGTL and Foothills System: These are 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. We are 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.

Canadian Mainline: 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.

Coastal GasLink: This pipeline supplies WCSB natural gas from interconnections with the NGTL System and other pipelines to the LNG Canada facility on the coast of British Columbia. This pipeline will also feed the Cedar LNG project once built later this decade. We have a 35 per cent equity interest and are the operator of this pipeline.

U.S. Natural Gas Pipelines

Columbia Gas: This is our natural gas transportation system for the Appalachian basin, which contains the Marcellus and Utica shale plays, two of the largest natural gas shale plays in North America. Similar to our footprint in the WCSB, our Columbia Gas assets are 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. We have a 60 per cent ownership interest and are the operator of this pipeline.

ANR: 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.

Columbia Gulf: 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. We have a 60 per cent ownership interest and are the operator of this pipeline.

Other U.S. Natural Gas Pipelines: We have ownership interests in nine wholly-owned or partially-owned natural gas pipelines serving major markets in the U.S.

Mexico Natural Gas Pipelines

Sur de Texas: This offshore pipeline transports natural gas from Texas to power and industrial markets in the eastern and central regions of Mexico. The average volumes transported by this pipeline in 2024 supplied approximately 17 per cent of Mexico's total natural gas imports via pipelines. We have a 60 per cent equity interest and are the operator of this pipeline.

Northwest System: The Topolobampo and Mazatlán pipelines make up our Mexico northwest system. The system runs through the states of Chihuahua and Sinaloa, supplying power plants and industrial facilities, bringing natural gas to a region of the country that previously did not have access to it.

TGNH System: This system is located in the central region of Mexico and is comprised of the Tamazunchale pipeline and the Tula, Villa de Reyes and Southeast Gateway pipelines with sections that are either in-service or currently under construction. This system supplies, or will supply, several power plants and industrial facilities in Campeche, Yucatán, Veracruz, Tabasco, San Luis Potosí, Querétaro and Hidalgo. It has interconnects with upstream pipelines that bring in supply from the Agua Dulce and Waha hubs in Texas. The TGNH System is part of a strategic alliance with the CFE, Mexico's state-owned electric utility, which holds a 13.01 per cent ownership interest in the system. We have an 86.99 per cent ownership interest and are the operator of these pipelines.

Guadalajara: This bidirectional pipeline 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.

Regulation of tolls and cost recovery

Our natural gas pipelines are generally regulated by the CER in Canada and FERC in the U.S. In Mexico, the regulation of our natural gas pipelines is being transitioned from the CRE to a new regulatory body under the Secretaría de Energía (SENER). These entities regulate the construction, operation and requested abandonment of pipeline infrastructure.

Regulators in Canada, the U.S. and Mexico 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 review our costs to ensure they are reasonable and prudently incurred and approve tolls that provide a reasonable opportunity to recover those costs.

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, as well as the Gulf of Mexico. 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 150 Bcf/d by 2028, reflecting an increase of approximately 28 Bcf/d from 2023 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 intensity reduction goal.

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

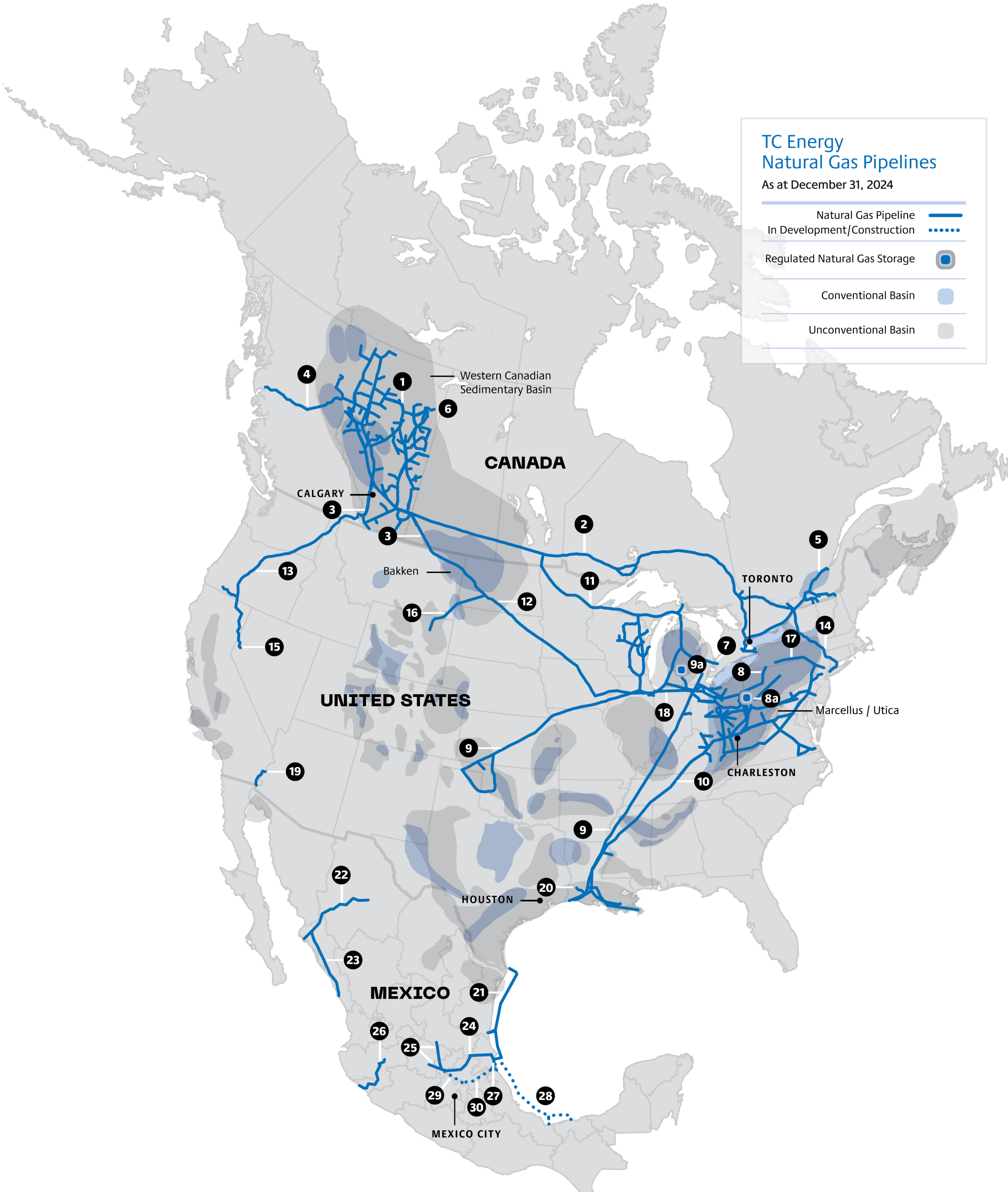
Changes in supply and demand levels and locations have resulted in increased competition to provide transportation services throughout North America. Our well-distributed footprint of natural gas pipelines, particularly in the low-cost WCSB and the Appalachian basin, both of which are connected to North 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 2025, we will continue to focus on the execution of our existing capital program that includes completing construction on our Southeast Gateway pipeline in Mexico, advancing the Cedar Link project which is an expansion of the Coastal GasLink pipeline, investment in the NGTL System and the initiation and completion of new U.S. pipeline projects. 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, 2024
Natural Gas Pipeline
In Development/Construction
Regulated Natural Gas Storage
Conventional Basin
Unconventional Basin
Western Canadian Sedimentary Basin
CANADA
CALGARY
Bakken
TORONTO
UNITED STATES
Marcellus / Utica
CHARLESTON
HOUSTON
MEXICO
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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			
1	NGTL System	24,233 km (15,058 miles)	Receives, transports and delivers natural gas within Alberta and British Columbia, and connects with Canadian Mainline, Coastal GasLink, Foothills and third-party pipelines.	100%
2	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.	100%
3	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%
4	Coastal GasLink	671 km (417 miles)	Transports natural gas from the Montney gas producing region to LNG Canada's liquefaction facility near Kitimat, British Columbia.	35%
5	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%
6	Ventures LP	133 km (83 miles)	Transports natural gas to the oil sands region near Fort McMurray, Alberta.	100%
7	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			
8	Columbia Gas	18,692 km (11,615 miles)	Transports natural gas primarily from the Appalachian basin to markets and pipeline interconnects throughout the U.S. Northeast, Midwest and Atlantic regions.	60%
8a	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
9	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.	100%
9a	ANR Storage	247 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key mid-western markets.	
10	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.	60%
11	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%
12	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%
13	Gas Transmission Northwest (GTN)	2,216 km (1,377 miles)	Transports WCSB and Rockies natural gas to Washington, Oregon and California. Connects with Tuscarora and Foothills.	100%
14	Iroquois	669 km (416 miles)	Connects with the Canadian Mainline and serves markets in New York.	50%
15	Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to markets in northeastern California and northwestern Nevada.	100%

		Length	Description	Ownership
16	Bison	488 km (303 miles)	Transports natural gas from the Powder River basin in Wyoming to Northern Border in North Dakota.	100%
17	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%
18	Crossroads	325 km (202 miles)	Interstate natural gas pipeline operating in Indiana and Ohio with multiple interconnects to other pipelines.	100%
19	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%
20	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%
	Mexico pipelines			
21	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.	60%
22	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.	100%
23	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.	100%
24	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.	86.99%
25	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%
26	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%
27	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 2025+ Facilities[2,3]	50 km (31 miles)	The VNBR project, along with other facilities expected to be placed in service 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			
	East Lateral XPress[1,2]	n/a	An expansion project on Columbia Gulf through compressor station modifications and additions expected to be placed in service in 2025.	60%
	VR Project[1,2]	n/a	A delivery market project on Columbia Gas that will replace and upgrade certain facilities while improving reliability and reducing emissions, which is expected to be placed in service in 2025.	60%
	WR Project[1,2]	n/a	A delivery market project on ANR that will replace and upgrade certain facilities while improving reliability and reducing emissions, which is expected to be placed in service in 2025.	100%
	Ventura XPress Project[1,2]	n/a	A project on ANR that will replace and upgrade certain facilities improving base system reliability, which is expected to be placed in service in 2025.	100%
	Mexico pipelines			
28	Southeast Gateway	715 km (444 miles)	Offshore pipeline that will connect to the Tula pipeline and transport gas to delivery points in Coatzacoalcos, Veracruz and Paraíso, Tabasco in Mexico's southeast region, which is expected to be placed in service on May 1, 2025.	86.99%
29	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]	n/a	A plan of multiple distinct projects for expansion facilities on the NGTL System with targeted in-service dates between 2027 and 2030.	100%
	U.S. pipelines			
	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
	Heartland Project[1,2]	n/a	An expansion project on ANR that will increase capacity and improve system reliability with upgrades to compression facilities, expected to be placed in service in 2027.	100%
	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%
	Pulaski Project[2,3]	64 km (40 miles)	A pipeline extension project on Columbia Gulf 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 Columbia Gulf designed to serve existing power plants. The project is expected to be placed in service in 2029.	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%

	Permitting and pre-construction phase (continued)	Length	Description	Ownership
	Mexico pipelines			
30	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 an 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 was declared commercially in service in fourth quarter 2024 and is regulated by the BC Energy Regulator (formerly the BC Oil & Gas Commission).

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. Equity is generally 40 per cent of the deemed capital structure, with the remaining 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 operated under the previous five-year revenue requirement settlement for 2020-2024, which included an incentive mechanism for certain operating costs and the opportunity to increase depreciation rates if tolls fall below specified levels. As of January 1, 2025, the NGTL System is operating under a new five-year revenue requirement settlement. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information. 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, 2024, the NGTL System placed approximately $0.6 billion of capacity projects in service.

2023 NGTL System Intra-Basin Expansion

The NGTL System Intra-Basin Expansion consists of 23 km (14 miles) of new pipeline and two new compressor stations. All assets have been placed in service, with a capital cost for the expansion of $0.5 billion.

NGTL System Revenue Requirement Settlement and Multi-Year Growth Plan

On September 26, 2024, the CER approved a five-year negotiated revenue requirement settlement on the NGTL System (2025-2029 NGTL Settlement) commencing on January 1, 2025.

The 2025-2029 NGTL Settlement enables an investment framework that supports our Board of Directors' approval to allocate approximately $3.3 billion of capital towards progression of the MYGP for expansion facilities on the NGTL System. It is comprised of multiple distinct projects with targeted in-service dates between 2027 and 2030, subject to final company and regulatory approvals. The completion of the MYGP is expected to enable approximately 1.0 Bcf/d of incremental system throughput.

This 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. It also introduces a new incentive mechanism to reduce both physical emissions and emissions compliance costs, which builds on the incentive mechanism for certain operating costs where variances from projected amounts and emissions savings are shared with our customers. A provision for review by customers exists in the settlement if tolls exceed a pre-determined level or if final company approvals of the MYGP are not obtained.

Sale of Equity Interest in the NGTL System and Foothills Pipeline Assets

The previously announced equity interest purchase agreement in respect of the sale by TC Energy of a 5.34 per cent interest in the NGTL System and Foothills Pipeline assets to an Indigenous-owned investment partnership was terminated by TC Energy on February 6, 2025.

Valhalla North and Berland River Project

The VNBR project will serve aggregate system requirements and connect migrating supply to key demand markets, designed to provide incremental capacity on the NGTL System of approximately 428 TJ/d (400 MMcf/d). With an estimated capital cost of $0.5 billion, the project consists of approximately 33 km (21 miles) of new pipeline, one new non-emitting electric compressor unit and associated facilities. Construction activities commenced in late 2024 with anticipated in-service dates commencing in second quarter 2026.

Coastal GasLink

Coastal GasLink Pipeline

The Coastal GasLink pipeline is a 671 km (417 mile) pipeline that transports natural gas from a receipt point in the Dawson Creek area of British Columbia to LNG Canada's (LNGC) natural gas liquefaction facility near Kitimat, B.C. Transportation service on the pipeline is underpinned by 25-year TSAs (with renewal provisions) with each of the five LNGC participants (LNGC Participants). We hold a 35 per cent ownership interest in Coastal GasLink LP, the entity that owns the Coastal GasLink pipeline. Additionally, we hold a 100 per cent ownership interest in the general partner of Coastal GasLink LP, the entity that is contracted to develop, construct and operate the pipeline.

The Coastal GasLink pipeline project achieved mechanical completion in 2023 and began delivering commissioning gas to the LNGC facility in late third quarter 2024. Post-construction reclamation activities are expected to be complete in 2025 and the project remains on track with its capital cost estimate of approximately $14.5 billion.

Coastal GasLink LP continues to pursue cost recovery, including certain arbitration proceedings which involve claims by, and the defense of certain claims against, Coastal GasLink LP. With the exception of settlements made with respect to certain contractor disputes, these claims have not yet been conclusively determined, but our expectation is that these proceedings are likely to result in net cost recoveries. Refer to Note 31, Commitments, contingencies and guarantees, of our 2024 Consolidated financial statements for additional information.

In June 2024, Coastal GasLink LP successfully completed a $7.15 billion refinancing of its existing construction credit facility through a private placement bond offering of senior secured notes to Canadian and U.S. investors. Proceeds from the offering were used to repay the majority of the outstanding $8.0 billion balance on Coastal GasLink LP’s construction credit facility. The remaining balance on the credit facility was settled through the use of proceeds from the unwinding of certain hedging arrangements associated with the construction facility.

In November 2024, Coastal GasLink LP executed a commercial agreement with LNGC and LNGC Participants that declared commercial in-service for the pipeline, allowing for the collection of tolls from customers retroactive to October 1, 2024. The agreement also includes a one-time payment of $199 million from LNGC Participants to TC Energy in recognition of the completion of certain work and the final settlement of costs. The payment is to be made by LNGC Participants upon the earlier of three months after the declared in-service of the LNGC facility, or December 15, 2025. The payment accrues in full to TC Energy in accordance with the contractual terms between the Coastal GasLink LP partners and has been accounted for as an in-substance distribution from Coastal GasLink LP.

In December 2024, following the commercial in-service of the pipeline, Coastal GasLink LP repaid the $3,147 million balance owing to TC Energy under the subordinated loan agreement. Our share of equity contributions required by Coastal GasLink LP to fund repayment of the loan amounted to $3,137 million. At December 31, 2024, our total share of partner equity contributions to fund the capital cost of the project was $5.3 billion. While unused capacity of $228 million remains available under the subordinated loan agreement, we do not anticipate that Coastal GasLink LP will draw on a significant portion of the remaining availability.

Cedar Link Expansion

In June 2024, Coastal GasLink LP sanctioned the Cedar Link project following a positive FID for the construction of the Cedar LNG facility by the Cedar LNG joint venture partners, Haisla Nation and Pembina Pipeline Corporation. The Cedar LNG facility is a proposed floating liquefied natural gas facility to be constructed in Kitimat, British Columbia. 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. With an estimated cost of $1.2 billion, the expansion project includes the addition of a new compressor station, connector pipeline and meter station to the existing Coastal GasLink pipeline infrastructure.

Funding for the expansion will be provided through project-level credit facilities of up to $1.4 billion secured by Coastal GasLink LP in June 2024, equity funding to be provided by Coastal GasLink LP partners, including us, and the recovery of construction carrying costs from LNGC Participants who have elected to make payments on a quarterly basis throughout construction. The incremental funds available through the project-level credit facilities and recovery of carrying charges provide additional contingency to mitigate future funding requirements for Coastal GasLink LP should costs exceed initial estimates of $1.2 billion. TC Energy has entered into an equity contribution agreement to fund up to a maximum of $37 million for its proportionate share of the equity requirements related to the Cedar Link project.

All major regulatory permits have been received and construction began in July 2024. The planned in-service date for the Cedar Link project is 2028, subject to the completion of plant commissioning activities at the Cedar LNG facility.

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. The equity option is exercisable after commercial in-service of the Coastal GasLink pipeline, subject to customary regulatory approvals and consents, including the consent of LNGC. As a result of the commercial agreement with LNGC and LNGC Participants, which has allowed for an earlier commercial in-service than the LNGC plant, we are actively collaborating with the Indigenous communities to establish a mutually agreeable timeframe in which the option can be exercised.

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 24 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2024	2023	2022
NGTL System	**2,393**	2,201	1,853
Canadian Mainline	**787**	789	770
Other Canadian pipelines[1]	**208**	345	183
Comparable EBITDA	**3,388**	3,335	2,806
Depreciation and amortization	**(1,382)**	(1,325)	(1,198)
Comparable EBIT	**2,006**	2,010	1,608
Specific items:			
Gain on sale of non-core assets	**10**	—	—
Coastal GasLink impairment charge	**—**	(2,100)	(3,048)
Segmented earnings (losses)	**2,016**	(90)	(1,440)

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.

In 2024, Canadian Natural Gas Pipelines segmented earnings were $2.0 billion compared to segmented losses of $0.1 billion and $1.4 billion in 2023 and 2022, respectively, 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 (2022 – $3.0 billion) related to our equity investment in Coastal GasLink LP. Refer to Note 7, Coastal GasLink, of our 2024 Consolidated financial statements for additional information.

Net income and comparable EBITDA for our rate-regulated Canadian natural gas pipelines are primarily affected by our approved ROE, investment base, the level of deemed common equity and incentive earnings. Changes in depreciation, financial charges and income taxes also impact comparable EBITDA, but 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 $)	2024	2023	2022
Net income			
NGTL System	**775**	770	708
Canadian Mainline	**244**	230	223
Average investment base			
NGTL System	**19,334**	19,008	17,493
Canadian Mainline	**3,697**	3,709	3,735

Net income for the NGTL System increased by $5 million in 2024 compared to 2023 and increased by $62 million in 2023 compared to 2022 mainly due to a higher average investment base resulting from continued system expansions, partially offset by an incentive loss. The NGTL System was operating under the 2020-2024 Revenue Requirement Settlement, which included an approved ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provided the NGTL System the opportunity to increase depreciation rates if tolls fall below specified levels and an incentive mechanism for certain operating costs where variances from projected amounts are shared with our customers. Refer to the Canadian Natural Gas Pipelines - Significant events section for additional information on the 2025 - 2029 NGTL Settlement.

Net income for the Canadian Mainline increased by $14 million in 2024 compared to 2023 and increased by $7 million in 2023 compared to 2022 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 $53 million higher in 2024 compared to 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.

Comparable EBITDA for Canadian Natural Gas Pipelines in 2023 was $529 million higher than 2022 primarily due to the net effect of:

- higher flow-through financial charges, depreciation and income taxes, as well as higher rate-base earnings on the NGTL System
- earnings from Coastal GasLink related to the recognition of a $200 million incentive payment upon meeting certain milestones, partially offset by lower development fee revenue resulting from timing of revenue recognition
- higher flow-through depreciation, financial charges and higher incentive earnings, partially offset by lower flow-through income taxes on the Canadian Mainline.

Depreciation and amortization

Depreciation and amortization was $57 million higher in 2024 compared to 2023, primarily reflecting incremental depreciation on the NGTL System from expansion facilities that were placed in service. Depreciation and amortization was $127 million higher in 2023 compared to 2022 due to higher depreciation on the NGTL System from expansion facilities that were placed in service and on the Canadian Mainline due to assets placed in service on a section with higher depreciation rates per the terms of the 2021-2026 Mainline Settlement.

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, earnings from Canadian rate-regulated natural gas pipelines are 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 2025 is expected to be higher than 2024 mainly due to higher contributions from the NGTL System resulting from the 2025-2029 NGTL Settlement. 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 2025 for the NGTL System and the Canadian Mainline to be consistent with 2024.

Capital expenditures

We incurred $1.3 billion of capital expenditures in 2024 in our Canadian Natural Gas Pipelines business on growth projects and maintenance capital expenditures. We expect to incur approximately $1.3 billion in 2025, primarily on NGTL System expansion projects and maintenance capital expenditures, all of which are immediately reflected in investment base and related earnings.

We also made a net contribution of $0.6 billion to our investment in Coastal GasLink LP in 2024, which was declared commercially in service in fourth quarter 2024. Significant equity contributions are not anticipated in 2025.

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 has recently and 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

Portland Natural Gas Transmission System

On March 4, 2024, we announced that TC Energy and its partner Northern New England Investment Company, Inc., a subsidiary of Énergir, entered into a purchase and sale agreement to sell PNGTS to BlackRock, through a fund managed by its Diversified Infrastructure business, and investment funds managed by Morgan Stanley Infrastructure Partners (the Purchaser). On August 15, 2024, we completed the sale of PNGTS for a gross purchase price of approximately $1.6 billion (US$1.1 billion), which included US$250 million of senior notes outstanding held at PNGTS and assumed by the Purchaser. A pre-tax gain of $572 million (US$408 million) and an after-tax gain of $456 million (US$323 million) were recognized for the year ended December 31, 2024. We are providing customary transition services and will continue to work jointly with the Purchaser to facilitate the safe and orderly transition of this natural gas system. Refer to Note 30, Strategic alliance, acquisitions and dispositions, of our 2024 Consolidated financial statements for additional information.

Gillis Access Project

In March 2024, the Gillis Access project, a 68 km (42 mile) greenfield pipeline system that connects gas production sourced from the Gillis hub to downstream markets in southeast Louisiana, was placed in service. The capital cost of this project was approximately US$0.3 billion.

In February 2023, we approved the 63 km (39 mile), 1.4 Bcf/d extension of the Gillis Access project to further connect supplies from Haynesville basin at Gillis. Effective September 1, 2024, all remaining shipper conditions have expired and the project expanded to 1.9 Bcf/d. The project has anticipated in-service dates starting in late 2026 and total estimated costs of US$0.4 billion.

Columbia Gas Section 4 Rate Case

In September 2024, Columbia Gas filed a Section 4 Rate Case with FERC requesting an increase to the maximum transportation rates expected to become effective April 1, 2025, subject to refund. We will pursue a collaborative process to find a mutually beneficial outcome with our customers through settlement.

Southeast Virginia Energy Storage Project

In November 2024, we approved the US$0.3 billion Southeast Virginia Energy Storage Project. This is an LNG peaking facility in southeast Virginia that will serve an existing LDC's growing winter peak day load and mitigate its peak day pricing exposure, as well as increase operational flexibility on the Columbia Gas system. The project has an anticipated in-service date of 2030.

Pulaski and Maysville Projects

In November 2024, we approved the Pulaski and Maysville projects on our Columbia Gulf System. These mainline extension projects off Columbia Gulf will facilitate full coal-to-gas conversion at two existing power plants and are each expected to provide 0.2 Bcf/d of capacity for incremental gas-fired generation. The projects have anticipated in-service dates in 2029 and total estimated costs of US$0.7 billion.

GTN XPress Project

In December 2024, the GTN XPress project, an expansion of the GTN system that will provide for the transport of incremental contracted export capacity facilitated by the NGTL System/Foothills West Path Delivery Program, was placed in service.
The capital cost of this project was approximately US$0.1 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 24 for more information on non-GAAP measures we use.

year ended December 31 (millions of US$, unless otherwise noted)	2024	2023	2022
Columbia Gas[1]	**1,600**	1,530	1,511
ANR	**642**	650	582
Columbia Gulf[1]	**235**	208	207
Great Lakes	**204**	183	178
GTN	**188**	202	184
PNGTS[1,2]	**66**	104	101
Other U.S. pipelines[3]	**359**	371	379
Comparable EBITDA	**3,294**	3,248	3,142
Depreciation and amortization	**(697)**	(692)	(681)
Comparable EBIT	**2,597**	2,556	2,461
Foreign exchange impact	**959**	895	742
Comparable EBIT (Cdn$)	**3,556**	3,451	3,203
Specific items:			
Gain on sale of PNGTS	**572**	—	—
Gain on sale of non-core assets	**38**	—	—
Great Lakes goodwill impairment charge	**—**	—	(571)
Risk management activities	**(113)**	80	(15)
Segmented earnings (losses) (Cdn$)	**4,053**	3,531	2,617

1 Includes non-controlling interest. Refer to the Corporate - Financial results section for additional information.
2 The sale of PNGTS was completed on August 15, 2024. Refer to the U.S. Natural Gas Pipelines – Significant events section for additional information.
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 2024 increased by $522 million compared to 2023 and increased by $914 million in 2023 compared to 2022 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 on August 15, 2024
- a pre-tax gain on sale of a non-core asset of $38 million in second quarter 2024
- a pre-tax goodwill impairment charge of $571 million related to Great Lakes in first quarter 2022
- 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 2024 and 2023 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$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 on August 15, 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.

Comparable EBITDA for U.S. Natural Gas Pipelines was US$106 million higher in 2023 than 2022 primarily due to the net effect of:
- incremental earnings from growth and modernization projects placed in service and additional contract sales on Columbia Gas, ANR and Great Lakes
- a net increase in earnings from ANR following the FERC-approved settlement for higher transportation rates effective August 2022, partially offset by decreased earnings due to the sale of natural gas from certain gas storage facilities in 2022
- higher realized earnings related to our U.S. natural gas marketing business primarily due to higher margins
- increased equity earnings from Iroquois and Northern Border
- decreased earnings due to higher operational costs, reflective of increased system utilization across our footprint, as well as higher property taxes related to projects in service
- reduced earnings from our mineral rights business due to lower commodity prices.

Depreciation and amortization

Depreciation and amortization was US$5 million higher in 2024 compared to 2023 and US$11 million higher in 2023 compared to 2022. The increase in depreciation is primarily due to new projects placed in service, 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 2025 is expected to be slightly higher than 2024 due to an anticipated increase in transportation rates on Columbia Gas, which is dependent on the outcome of the Section 4 Rate Case filed with FERC. In addition, revenues are expected to increase following the completion of expansion projects in 2025 on the Columbia Gas, Columbia Gulf and ANR systems, as well as full year in-service of the Gillis Access project. Our pipeline systems continue to see historically strong demand for service and we anticipate that during 2025, our assets will maintain the high utilization levels experienced in 2024. These positive results are expected to be partially offset by higher operational costs, reflective of continued increases to system utilization across our footprint, the impact of the sale of our 61.7 per cent equity interest in PNGTS in 2024 and an anticipated increase in property taxes from capital projects placed in service.

Capital expenditures

We incurred a total of US$2.2 billion of capital expenditures in 2024 on our U.S. natural gas pipelines and expect to incur approximately US$2.5 billion in 2025 primarily on our Columbia Gas, ANR and Columbia Gulf expansion projects and Bison XPress equity contributions, 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 2025 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

In August 2022, we announced a strategic alliance with Mexico's state-owned electric utility, the CFE, for the development of new natural gas infrastructure in central and southeast Mexico. In connection with the strategic alliance, we reached an FID to develop and construct the Southeast Gateway pipeline, a 1.3 Bcf/d, 715 km (444 mile) offshore natural gas pipeline to serve the southeast region of Mexico. We continue to be aligned with the CFE on finalizing the remaining project completion activities for achieving an in-service date of May 1, 2025. The estimated project cost for the Southeast Gateway pipeline is approximately US$3.9 billion, which is lower than the initial cost estimate of US$4.5 billion.

During second quarter 2024, upon the CFE's equity injection of US$340 million as well as non-cash consideration in recognition of the completion of certain contractual obligations, including land acquisition and permitting support, the CFE became a partner in TGNH with a 13.01 per cent equity interest. Provided that the CFE's contractual commitments are met related to land acquisition, community relations and permitting support, the CFE's equity in TGNH would build up to a maximum of 15 per cent with the in-service of the Southeast Gateway pipeline and will increase to approximately 35 per cent upon expiry of the contract in 2055. Refer to Note 30, Strategic alliance, acquisitions and dispositions, of our Consolidated financial statements for additional information.

Tula

In third quarter 2022, we placed the east section of the Tula pipeline into commercial service and we reached an agreement with the CFE to jointly develop and complete the remaining segments of the Tula pipeline, with the central segment subject to an FID. Due to the delay of an FID, recording AFUDC on the assets under construction for the Tula pipeline project was suspended in late 2023.

Villa de Reyes

We placed the north and lateral sections of the Villa de Reyes pipeline into commercial service in third quarter 2022 and third quarter 2023, respectively. We continue to work with our partner, the CFE, to complete the south section of the Villa de Reyes pipeline. The in-service date will be determined upon resolution of outstanding stakeholder issues.

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 24 for more information on non-GAAP measures we use.

year ended December 31 (millions of US$, unless otherwise noted)	**2024**	**2023**	**2022**
TGNH[1,2]	**231**	232	164
Sur de Texas[3]	**220**	75	112
Topolobampo	**156**	157	161
Guadalajara	**56**	61	73
Mazatlán	**67**	71	67
Comparable EBITDA	**730**	596	577
Depreciation and amortization	**(67)**	(66)	(76)
Comparable EBIT	**663**	530	501
Foreign exchange impact	**244**	186	153
Comparable EBIT (Cdn$)	**907**	716	654
Specific item:			
Expected credit loss provision on net investment in leases and certain contract assets in Mexico[2]	**22**	80	(163)
Segmented earnings (losses) (Cdn$)	**929**	796	491

1 Includes the operating sections of the Tamazunchale, Villa de Reyes and Tula 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 2024 increased by $133 million compared to 2023 and increased by $305 million in 2023 compared to 2022 and included the impact of a $22 million unrealized recovery in 2024 (2023 – $80 million unrealized recovery; 2022 – $163 million unrealized loss) 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 28, Risk management and financial instruments, of our 2024 Consolidated financial statements 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. dollar-denominated operations in Mexico. Refer to the Foreign exchange section for additional information.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$134 million in 2024 compared to 2023 mainly due to the net effect of:

- higher equity earnings in Sur de Texas primarily due to foreign exchange impacts upon the revaluation of peso-denominated liabilities as a result of a weaker Mexican peso and lower income tax expense mainly due to foreign exchange impacts. We use foreign exchange derivatives to manage this exposure, the impact of which is recognized in Foreign exchange (gains) losses, net in the Consolidated statement of income. Refer to the Foreign exchange section for additional information
- lower earnings from Guadalajara primarily due to lower fixed revenue in accordance with the current transportation contract and higher operating costs.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$19 million in 2023 compared to 2022 primarily due to:

- higher earnings in TGNH primarily related to the commercial in-service of the north section of the Villa de Reyes pipeline and the east section of the Tula pipeline in third quarter 2022, as well as the commercial in-service of the lateral section of the Villa de Reyes pipeline in third quarter 2023
- lower earnings from Guadalajara primarily due to lower fixed revenue in accordance with the current transportation contract and higher operating costs associated with a disruption of service due to a weather event
- lower equity earnings in Sur de Texas primarily due to foreign exchange impacts upon the revaluation of peso-denominated liabilities as a result of a stronger Mexican peso and increased interest expense due to higher interest rates. We use foreign exchange derivatives to manage this exposure, the impact of which is recognized in Foreign exchange (gains) losses, net in the Consolidated statement of income.

Depreciation and amortization

Depreciation and amortization was generally consistent in 2024 compared to 2023. Depreciation and amortization was US$10 million lower in 2023 compared to 2022 due to the change to lease accounting for Tamazunchale subsequent to the execution of the TGNH TSA with the CFE in mid-2022. Under sales-type lease accounting, our in-service TGNH pipeline assets are reflected on our Consolidated balance sheet within net investment in leases with no depreciation expense being recognized.

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 2025 is expected to be higher than 2024 due to the Southeast Gateway project that is expected to be placed into commercial service on May 1, 2025.

Capital expenditures

We incurred US$1.5 billion of capital expenditures in 2024 primarily related to the construction of the Southeast Gateway and Villa de Reyes pipelines. We expect to incur approximately US$0.4 billion in 2025 to finalize construction of the Southeast Gateway and Villa de Reyes pipelines.

NATURAL GAS PIPELINES – BUSINESS RISKS

The following are risks specific to our Natural Gas Pipelines business. Refer to page 102 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 ability to grow 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 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. Beyond our existing portfolio, we will focus our capital investment in sectors and projects that offer commercial frameworks consistent with TC Energy's value proposition, namely long-term contracts and rate regulation. 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 a vital role in decarbonizing energy sources and will continue to build expertise and capabilities in emerging technologies and markets that we believe will fit these criteria in the future and have synergies with our natural gas business.

Recent highlights

- Bruce Power completed planned outages on Unit 1 and Unit 7 and completed a Vacuum Building inspection where Units 5, 6 and 8 were also shut down in 2024. On January 31, 2025, Unit 4 was removed from service to commence its MCR program
- The Unit 5 MCR final cost and schedule estimate was submitted to the IESO on January 31, 2025
- Executed contract extensions of five years at Mackay River and 10 years at Grandview cogeneration plants
- TC Energy and prospective partners Saugeen Ojibway Nation will advance pre-development work on the Ontario Pumped Storage Project following the Ontario Government's recent announcement on January 24, 2025 to invest up to $285 million. With the Ontario Government’s investment, the project can now advance 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 the Board of Directors, Saugeen Ojibway Nation and the Ontario Government will each make a final decision on the project following further definition and completion of a detailed cost estimate.

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. Our two eastern Canadian natural gas-fired cogeneration assets, Bécancour and Grandview, are fully contracted.

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 has begun to progress 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. 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 30 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, the second unit in the MCR program, commenced in first quarter 2023 and has an expected completion in 2026. The Unit 4 MCR final cost and schedule estimate was approved by the IESO on February 8, 2024. Unit 4 was removed from service on January 31, 2025 to commence its MCR program with expected completion in 2028. Investments in the remaining three units' MCR programs are expected to continue through 2033. The Unit 5 MCR final cost and schedule estimate was submitted to the IESO on January 31, 2025. 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, which could include integration with storage and other forms of energy, 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 2024 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 2022 to 2024 period have been provided for at December 31, 2024 and no operating cost efficiencies were realized for the 2019 to 2021 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 plans to expand Lutetium-177 isotope production used in the treatment of prostate cancer and neuroendocrine tumours. This project was undertaken with a Canadian-based nuclear medicine partnership and the Saugeen Ojibway Nation, on whose traditional territory the Bruce Power facilities are located. Furthermore, Bruce Power and its partners in the production of medical isotopes have committed to building a hot cell facility in Bruce County, expediting their ability to process short-lived lutetium-177 to ensure it reaches cancer patients around the world in a timely fashion.

Power Purchase Agreements – Canada

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 – U.S.

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 – U.S.

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

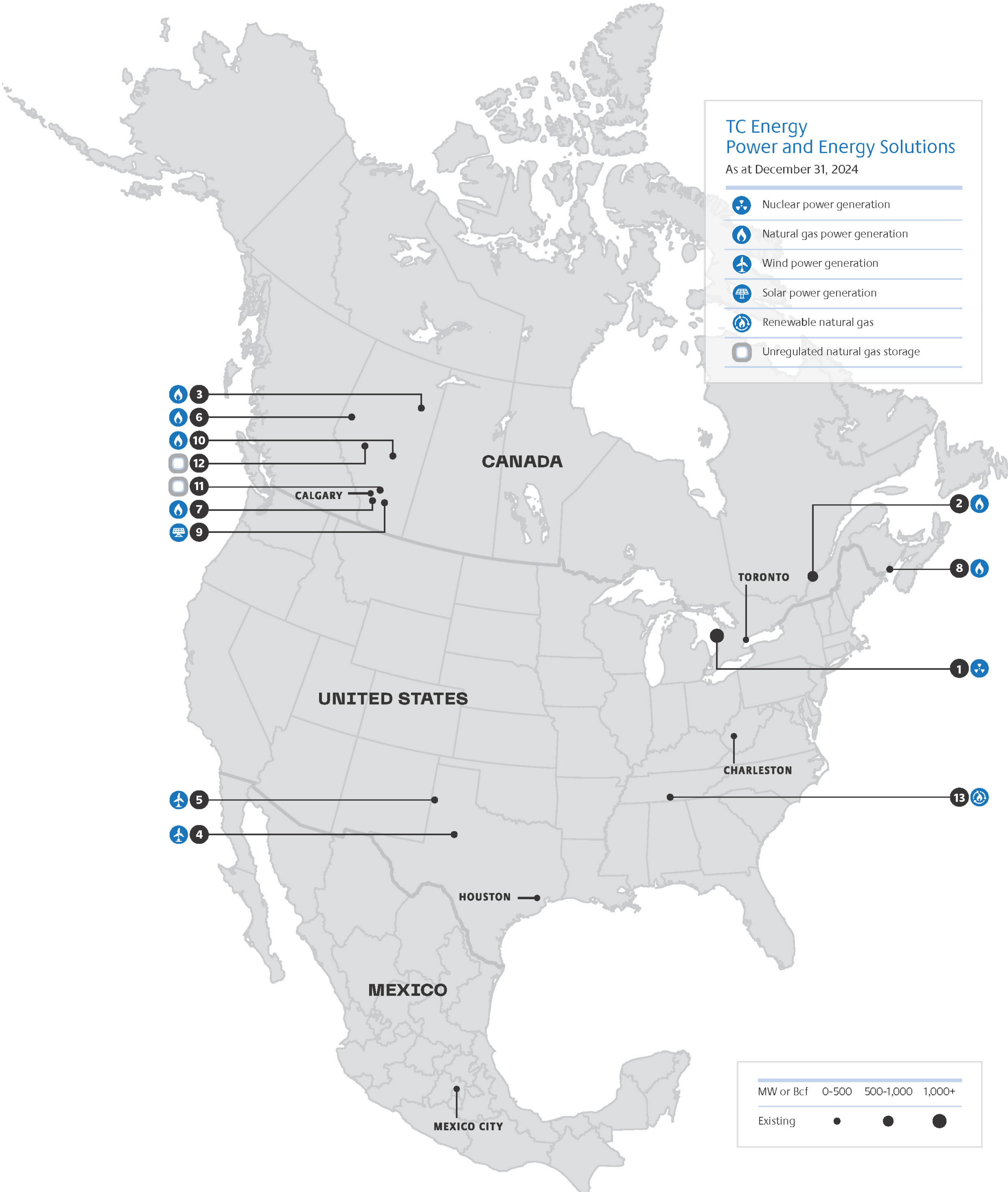
Canadian Natural Gas Storage

We own and operate 118 Bcf of non-regulated natural gas storage capacity in Alberta. This business operates independently from our regulated natural gas transmission and U.S. storage businesses.

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, 2024
Nuclear power generation
Natural gas power generation
Wind power generation
Solar power generation
Renewable natural gas
Unregulated natural gas storage
CANADA
UNITED STATES
MEXICO
CALGARY
TORONTO
CHARLESTON
HOUSTON
MEXICO CITY
1
2
3
4
5
6
7
8
9
10
11
12
13
MW or Bcf
0-500
500-1,000
1,000+
Existing

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

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

The Unit 5 MCR final cost and schedule estimate was submitted to the IESO on January 31, 2025.

Uprate Initiative

On November 19, 2024, we announced that Bruce Power is progressing with Stage 3a of Project 2030, which is designed to provide incremental capacity of approximately 90 MW at the site. TC Energy's share of the capital required is approximately $175 million. Bruce Power will not be requesting an incremental capital call for this stage. By optimizing its existing Units through this program, when complete, Project 2030 is expected to increase the Bruce Power site peak output to 7,000 MW. All of this output will be sold under Bruce Power's long-term contract with the IESO.

Ontario Pumped Storage

TC Energy and prospective partners Saugeen Ojibway Nation will advance pre-development work on the Ontario Pumped Storage Project following the Ontario Government's recent announcement on January 24, 2025 to invest up to $285 million. With the Ontario Government's investment, the project can now advance 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 TC Energy's Board of Directors, Saugeen Ojibway Nation and the Ontario Government will each make a final decision on the project following further definition and completion of a detailed cost estimate.

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 24 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2024	2023	2022
Bruce Power[1]	**890**	680	552
Canadian Power	**273**	334	322
Natural Gas Storage and other[2]	**51**	6	33
Comparable EBITDA	**1,214**	1,020	907
Depreciation and amortization	**(101)**	(92)	(72)
Comparable EBIT	**1,113**	928	835
Specific items:			
Project Tundra impairment charge	**(36)**	—	—
Bruce Power unrealized fair value adjustments	**8**	7	(17)
Risk management activities	**17**	69	15
Segmented earnings (losses)	**1,102**	1,004	833

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 increased by $98 million in 2024 compared to 2023 and increased by $171 million in 2023 compared to 2022 and included the following specific items, which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax impairment charge of $36 million related to development costs incurred on Project Tundra, a next-generation technology carbon capture and storage project, following our decision to end our collaboration on the project
- 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 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.

Comparable EBITDA for Power and Energy Solutions increased by $113 million in 2023 compared to 2022 primarily due to the net effect of:

- higher contributions from Bruce Power primarily due to a higher contract price, reduced outage costs with fewer planned outage days and lower depreciation expense, partially offset by lower generation and increased operating expenses
- increased Canadian Power financial results primarily from lower natural gas fuel costs and higher realized power prices
- decreased Natural Gas Storage and other results due to increased business development costs.

Depreciation and amortization

Depreciation and amortization increased by $9 million in 2024 compared to 2023 and increased by $20 million in 2023 compared to 2022 and were 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 24 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)	**2024**	**2023**	**2022**
Items included in comparable EBITDA and comparable EBIT are comprised of:			
Revenues[1]	**2,242**	1,941	1,848
Operating expenses	**(984)**	(917)	(924)
Depreciation and other	**(368)**	(344)	(372)
Comparable EBITDA and comparable EBIT[2]	**890**	680	552
Bruce Power – other information			
Plant availability[3,4]	**92%**	92%	86%
Planned outage days[4]	**160**	106	302
Unplanned outage days	**32**	62	34
Sales volumes (GWh)[5]	**22,209**	20,447	20,610
Realized power price per MWh[6]	**$100**	$94	$89

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.
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.

Bruce Power's 2024 planned maintenance, on Units 5 to 8, excluding the MCR program, was completed in second quarter. A planned outage on Unit 4 was completed in second quarter 2023 and on Unit 8 in fourth quarter 2023. In 2022, planned maintenance was completed on all units.

OUTLOOK

Comparable EBITDA

Power and Energy Solutions comparable EBITDA in 2025 is expected to be lower than 2024 primarily from decreased Bruce Power equity income due to the removal of Unit 4 from service on January 31, 2025 to commence its MCR outage, partially offset by a higher contract price and fewer non-MCR planned outage days. Lower Alberta power prices and higher natural gas prices in 2025 are expected to reduce contributions from Canadian Power. These reductions are expected to be partially offset by lower business development activities in 2025.

Planned maintenance at Bruce Power in 2025 is currently scheduled to begin on Unit 5 in the first quarter and on Unit 2 in the third quarter. The average 2025 plant availability percentage, excluding the Unit 3 and Unit 4 MCR programs, is expected to be in the low-90 per cent range.

Capital expenditures

We incurred $0.8 billion of capital expenditures in 2024 primarily on our share of the Unit 3 MCR program at Bruce Power and maintenance capital projects across the segment. We expect to incur approximately $0.9 billion in 2025 primarily related to our share of Bruce Power's Unit 3 and Unit 4 MCR programs.

BUSINESS RISKS

The following are risks specific to our Power and Energy Solutions business. Refer to page 102 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

NGTL System Ownership Transfer

On April 1, 2024, ownership of the NGTL System was transferred from Nova Gas Transmission Ltd. to NGTL GP Ltd. on behalf of NGTL Limited Partnership as part of an ordinary course corporate reorganization to support business optimization and facilitate future minority ownership of the NGTL System, including participation from Indigenous groups. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information. The reorganization will not impact the operations of the NGTL System. As a limited partnership, NGTL LP is not subject to Canadian corporate income taxes. The related income tax obligations are those of the partners.

For the year ended December 31, 2024, we incurred costs of $42 million after tax related to the NGTL System Ownership Transfer, which has been excluded from comparable measures.

2016 Columbia Pipeline Acquisition Lawsuit

In 2023, the Delaware Chancery Court (the Court) issued its decision in the class action lawsuit commenced by former shareholders of Columbia Pipeline Group Inc. (CPG) related to the acquisition of CPG by TC Energy in 2016. 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.

On May 15, 2024, the Court allocated responsibility for the total sale process damages of US$398 million in the amount of 50 per cent to the former Columbia CEO and CFO, collectively, and 50 per cent to TC Energy. Pursuant to the Final Order and Judgment (Final Judgment), TC Energy's allocated share of the sale process claim damages is US$199 million, plus US$153 million in interest as of June 14, 2024. The Court also entered judgment related to a disclosure claim for which TC Energy's allocated share of damages is US$84 million, plus US$64 million in interest as of June 14, 2024. The damages for the two claims are not cumulative and TC Energy would only be required to pay the greater of the sale process damages and disclosure claim damages after final determination of those amounts on appeal, including any additional interest assessed to the date of payment.

TC Energy disagrees with many of the Court's findings and believes the Court's ruling departs from established Delaware law. TC Energy has filed a notice of appeal, which is scheduled to be heard by the Delaware Supreme Court on March 12, 2025. A final decision is expected in mid-2025. During the appeal process, in lieu of paying the judgment, TC Energy posted an appeal bond in the amount of US$380 million, which approximates the amount of the Final Judgment plus nine months of post-judgment interest. Our legal assessment is that it is not probable that TC Energy will incur a loss upon completion of the appeal process, and therefore, we have not accrued a provision for this claim at December 31, 2024.

Focus Project

In late 2022, we launched the Focus Project to identify opportunities to improve safety, productivity and cost-effectiveness. To date, we have designed and implemented a broad set of initiatives to further enhance safety, as well as improve operational and financial performance over the long term.

The expected impacts of project initiatives have been included in our outlook for 2025 and no significant incremental project costs are expected beyond 2024. The program will wind down in 2025 as we finalize implementation of certain initiatives. The core elements of the project are embedded into our business processes to sustain performance improvements over the long term.

For the year ended December 31, 2024 we have incurred pre-tax costs of $45 million (2023 – $124 million) for the Focus Project primarily related to severance costs, of which $24 million (2023 – $65 million, primarily external consulting) was recorded in Plant operating costs and other in the Consolidated statement of income and was excluded from comparable measures. An additional $14 million for the year ended December 31, 2024 (2023 – $23 million) was recorded in Plant operating costs and other with offsetting revenues related to costs recoverable through regulatory and commercial tolling structures, the net effect of which had no impact on net income. For the year ended December 31, 2024, $7 million (2023 – $36 million) was allocated to capital projects.

Asset Divestiture Program

Our asset divestiture program, which included completing the sale of PNGTS and the CFE's equity injection resulting in a 13.01 per cent equity interest in TGNH in 2024, as well as the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf in 2023, collectively contributed to our deleveraging goal. Any further capital rotation opportunities will be assessed in the normal course of our business.

2024 Canadian Legislation

On June 20, 2024, two pieces of Canadian legislation, Bill C-59 and Bill C-69 were enacted into law, which, among other things, included the excessive interest and financing expenses limitation (EIFEL) rules and the Global Minimum Tax Act. We do not expect a material impact on our financial performance and cash flows as a result of the new legislation.

TC Energy has disallowed interest expense related to the EIFEL legislation and expects further restrictions on interest deductibility. However, through on-going monitoring and management, we expect the disallowed interest to be utilized. We will also continue to monitor developments related to EIFEL legislation and assess its impacts to the business.

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 24 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2024	2023[1]	2022[1]
Comparable EBITDA	**(63)**	(73)	(72)
Depreciation and amortization	**(5)**	(6)	(7)
Comparable EBIT	**(68)**	(79)	(79)
Specific items:			
Third-party settlement	**(34)**	—	—
Focus Project costs	**(24)**	(65)	—
NGTL System ownership transfer costs	**(10)**	—	—
Foreign exchange gains – inter-affiliate loans[2]	**—**	—	28
Segmented earnings (losses)	**(136)**	(144)	(51)

1 Prior year results have been recast to reflect continuing operations only.
2 Reported in Income (loss) from equity investments in the Consolidated statement of income.

In 2024, Corporate segmented losses were $136 million compared to $144 million and $51 million in 2023 and 2022, 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. Refer to the Corporate – Significant events section for additional information
- a pre-tax charge of $10 million in 2024 related to the NGTL System Ownership Transfer. Refer to the Corporate – Significant events section for additional information
- foreign exchange gains in 2022 on our proportionate share of peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners up to March 15, 2022 when the peso-denominated inter-affiliate loans were fully repaid upon maturity. These foreign exchange gains were recorded in Income from equity investments in the Corporate segment and were excluded from our calculation of comparable EBITDA and comparable EBIT as they were fully offset by corresponding foreign exchange losses on the inter-affiliate loan receivable included in Foreign exchange gains (losses), net. Refer to the Other information – Related party transactions section for additional information.

Comparable EBITDA for Corporate was a loss of $63 million in 2024 compared to a loss of $73 million in 2023, primarily due to 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. Refer to the Discontinued operations section for additional information. Comparable EBITDA for Corporate in 2023 was generally consistent compared to 2022.

Depreciation and amortization

Depreciation and amortization was generally consistent between 2024 and 2023 and between 2023 and 2022.

OTHER INCOME STATEMENT ITEMS

Interest expense

year ended December 31 (millions of $)	2024	2023[1]	2022[1]
Interest expense on long-term debt and junior subordinated notes			
Canadian dollar-denominated	**(856)**	(895)	(776)
U.S. dollar-denominated	**(1,855)**	(1,692)	(1,267)
Foreign exchange impact	**(685)**	(592)	(383)
	(3,396)	(3,179)	(2,426)
Other interest and amortization expense	**(147)**	(261)	(189)
Capitalized interest	**191**	187	27
Interest expense allocated to discontinued operations	**176**	287	288
Interest expense included in comparable earnings	**(3,176)**	(2,966)	(2,300)
Specific items:			
Net gain on debt extinguishment	**228**	—	—
Risk management activities	**(71)**	—	—
Interest expense	**(3,019)**	(2,966)	(2,300)

1 Prior year results have been recast to reflect continuing operations only.

Interest expense increased by $53 million in 2024 compared to 2023 and increased by $666 million in 2023 compared to 2022. 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. Refer to the Financial condition section for additional information
- 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 2024 increased by $210 million compared to 2023 primarily 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 stronger U.S. dollar on translation of U.S. dollar-denominated interest expense
- reduced levels of short-term borrowing.

Interest expense included in comparable earnings in 2023 increased by $666 million compared to 2022 mainly due to the net effect of:

- long-term debt issuances and maturities
- the foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest expense
- higher interest rates on our long-term debt that bears interest at a floating rate
- higher capitalized interest, largely due to funding related to our investment in Coastal GasLink LP. Refer to Note 7, Coastal GasLink, of our 2024 Consolidated financial statements for additional information.

Refer to the Financial condition section for additional information.

Allowance for funds used during construction

year ended December 31 (millions of $)	2024	2023	2022
Allowance for funds used during construction			
Canadian dollar-denominated	**34**	102	157
U.S. dollar-denominated	**546**	350	161
Foreign exchange impact	**204**	123	51
Allowance for funds used during construction	**784**	575	369

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. 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.

AFUDC increased by $206 million in 2023 compared to 2022. The decrease in Canadian dollar-denominated AFUDC is primarily related to NGTL System expansion projects placed in service. The increase in U.S. dollar-denominated AFUDC is the result of the reactivation of AFUDC on the TGNH assets under construction following the new TSA with the CFE, as well as capital expenditures on the Southeast Gateway pipeline project in 2023, partially offset by projects placed in service on our U.S. natural gas pipelines. Effective November 1, 2023, AFUDC was suspended on the assets under construction for the Tula pipeline project, due to the delay of an FID.

Foreign exchange gains (losses), net

year ended December 31 (millions of $)	2024	2023	2022
Foreign exchange gains (losses), net included in comparable earnings	**(85)**	118	(8)
Specific items:			
Foreign exchange gains (losses), net – intercompany loan[1]	**204**	(44)	—
Foreign exchange losses – inter-affiliate loan	**—**	—	(28)
Risk management activities	**(266)**	246	(149)
Foreign exchange gains (losses), net	**(147)**	320	(185)

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

Foreign exchange losses, net were $147 million in 2024 compared to foreign exchange gains, net of $320 million in 2023 and foreign exchange losses, net of $185 million in 2022. 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
- foreign exchange losses on the peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture until March 15, 2022, when it was fully repaid upon maturity. The interest income and interest expense on the peso-denominated inter-affiliate loan was included in comparable earnings with all amounts offsetting and resulting in no impact on consolidated net income. Refer to the Other information – Related party transactions section for additional information
- 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 losses, net included in comparable earnings were $85 million in 2024 compared to foreign exchange gains, net of $118 million in 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 the second quarter 2024 on the partial repayment of the peso-denominated intercompany loan between TCPL and TGNH.

Foreign exchange gains, net included in comparable earnings were $118 million in 2023 compared to foreign exchange losses, net of $8 million in 2022. 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
- higher foreign exchange losses on the revaluation of our peso-denominated net monetary liabilities to U.S. dollars.

Interest income and other

year ended December 31 (millions of $)	**2024**	**2023**[1]	**2022**[1]
Interest income and other	**324**	272	140

1 Prior year results have been recast to reflect continuing operations only.

Interest income and other increased by $52 million in 2024 compared to 2023 due to higher interest earned on short-term investments and a reduction in insurance-related provisions.

Interest income and other increased by $132 million in 2023 compared to 2022 due to higher interest earned on short-term investments and the change in fair value of other restricted investments, partially offset by lower interest income in 2023 due to the repayment of the inter-affiliate loan receivable from Sur de Texas joint venture in July 2022.

Income tax (expense) recovery

year ended December 31 (millions of $)	2024	2023[1]	2022[1]
Income tax (expense) recovery included in comparable earnings	**(772)**	(890)	(660)
Specific items:			
Gain on sale of PNGTS	**(116)**	—	—
Revaluation of deferred tax balances	**(96)**	—	—
Net gain on debt extinguishment	**(50)**	—	—
Foreign exchange gains (losses), net – intercompany loan	**10**	—	—
Gain on sale of non-core assets	**15**	—	—
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**(7)**	(25)	49
Third-party settlement	**8**	—	—
Project Tundra impairment charge	**9**	—	—
Focus Project costs	**6**	17	—
NGTL System ownership transfer costs	**(32)**	—	—
Coastal GasLink impairment charge	**—**	157	405
Great Lakes goodwill impairment charge	**—**	—	40
Settlement of Mexico prior years' income tax assessments	**—**	—	(196)
Bruce Power unrealized fair value adjustments	**(2)**	(2)	4
Risk management activities	**105**	(99)	36
Income tax (expense) recovery	**(922)**	(842)	(322)

1 Prior year results have been recast to reflect continuing operations only.

Income tax expense in 2024 increased by $80 million compared to 2023 and increased by $520 million in 2023 compared to 2022.

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.

2022

- a $405 million income tax recovery related to the impairment of our equity investment in Coastal GasLink LP, net of certain unrealized tax losses not recognized
- $196 million expense related to the settlement of prior years' income tax assessments related to our operations in Mexico.

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.

Income tax expense included in comparable earnings in 2023 increased by $230 million compared to 2022 primarily due to higher earnings subject to income tax, Mexico foreign exchange exposure and lower foreign income tax rate differentials, partially offset by lower flow-through income taxes and lower Mexico inflationary adjustments. Refer to the Foreign exchange section for additional information.

Net (income) loss attributable to non-controlling interests

year ended December 31 (millions of Canadian $)	Non-Controlling Interests Ownership at December 31, 2024	2024	2023	2022
Columbia Gas and Columbia Gulf[1]	40 %	**(571)**	(143)	—
PNGTS[2]	nil	**(30)**	(41)	(37)
Texas Wind Farms[3]	100 %	**29**	38	—
TGNH[4]	13.01 %	**(48)**	—	—
Net (income) loss attributable to non-controlling interests included in comparable earnings		**(620)**	(146)	(37)
Specific item:				
Foreign exchange (gains) losses, net – intercompany loan		**(61)**	—	—
Net (income) loss attributable to non-controlling interests		**(681)**	(146)	(37)

1 On October 4, 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 The sale of PNGTS was completed on August 15, 2024. Refer to the U.S. 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 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.

Net income attributable to non-controlling interests increased by $535 million in 2024 compared to 2023 and includes the non-controlling interest portion of the unrealized foreign exchange gains and losses on the TGNH peso-denominated intercompany loan payable to TCPL, which has been removed from our calculation of Net (income) loss attributable to non-controlling interests included in comparable earnings. Net income attributable to non-controlling interests included in comparable earnings increased by $474 million 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. Refer to the Mexico Natural Gas Pipelines – Significant events section for additional information.

Net income attributable to non-controlling interests increased by $109 million in 2023 compared to 2022 due to the net effect of the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf and the acquisition of the Texas Wind Farms.

Preferred share dividends

year ended December 31 (millions of $)	2024	2023	2022
Preferred share dividends	**(104)**	(93)	(107)

Preferred share dividends increased by $11 million in 2024 compared to 2023 primarily due to the dividend rate resets on Series 7 preferred shares and Series 9 preferred shares on April 30, 2024 and October 30, 2024, respectively. Preferred share dividends decreased $14 million in 2023 compared to 2022 primarily due to the redemption of preferred shares in 2022, partially offset by higher floating dividend rates on certain series of preferred shares.

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, 2024, 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$)	2024	2023[1]	2022[1]
Comparable EBITDA			
U.S. Natural Gas Pipelines	**3,294**	3,248	3,142
Mexico Natural Gas Pipelines[2]	**730**	596	602
	4,024	3,844	3,744
Depreciation and amortization	**(764)**	(758)	(757)
Interest on long-term debt and junior subordinated notes	**(1,855)**	(1,692)	(1,267)
Interest expense allocated to discontinued operations	**125**	189	182
Allowance for funds used during construction	**546**	350	161
Net income (loss) attributable to non-controlling interests included in comparable earnings and other	**(481)**	(156)	(101)
	1,595	1,777	1,962
Average exchange rate – U.S. to Canadian dollars	**1.37**	1.35	1.30

1 Prior year results have been recast to reflect continuing operations only.

2 Excludes interest expense on our inter-affiliate loans with the Sur de Texas joint venture which was fully offset in Interest income and other. These inter-affiliate loans were fully repaid in 2022.

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, 2024	**20.87**
December 31, 2023	16.91
December 31, 2022	19.50

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 $)	**2024**	**2023**	**2022**
Comparable EBITDA – Mexico Natural Gas Pipelines[1]	**115**	(83)	(32)
Foreign exchange gains (losses), net included in comparable earnings	**(53)**	224	54
Income tax (expense) recovery included in comparable earnings	**110**	(133)	(11)
Net (income) loss attributable to non-controlling interests included in comparable earnings[2]	**(11)**	—	—
	161	8	11

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 $25 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, 2024, excluding discontinued operations, our current assets totaled $5.5 billion and current liabilities amounted to $10.3 billion, leaving us with a working capital deficit of $4.8 billion compared to $0.8 billion at December 31, 2023. 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 $8.0 billion of committed revolving credit facilities available for short-term borrowing capacity, of which $7.6 billion of short-term borrowing capacity remains available, net of $0.4 billion backstopping outstanding commercial paper balances. We also have arrangements in place for a further $2.0 billion of demand credit facilities on which $1.1 billion remains available as of December 31, 2024
- additional $2.2 billion committed revolving credit facilities at certain of our subsidiaries and affiliates, on which no amounts have been drawn
- 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, 2024 were $117.9 billion compared to $109.5 billion at December 31, 2023. The increase primarily reflects our capital spending program, increased equity investments and a stronger U.S. dollar at December 31, 2024 compared to December 31, 2023 on translation of our U.S. dollar-denominated assets, partially offset by depreciation and working capital.

At December 31, 2024 our total liabilities from continuing operations were $79.6 billion, compared to $82.1 billion at December 31, 2023 due to the net effect of a reduction in debt, working capital and a stronger U.S. dollar at December 31, 2024 compared to December 31, 2023 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)	2024	Per cent of total	2023	Per cent of total
Notes payable	**387**	**1**	—	—
Long-term debt, including current portion	**47,931**	**49**	52,914	54
Cash and cash equivalents	**(801)**	**(1)**	(3,678)	(4)
	47,517	**49**	49,236	50
Junior subordinated notes	**11,048**	**11**	10,287	10
Preferred shares	**2,499**	**3**	2,499	3
Common shareholders' equity	**25,093**	**26**	27,054	27
Non-controlling interests	**10,768**	**11**	9,455	10
	96,925	**100**	98,531	100

Provisions of various trust indentures and credit arrangements 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, 2024.

Cash flows[1,2]

The following tables summarize our consolidated cash flows.

year ended December 31 (millions of $)	2024	2023	2022
Net cash provided by operations	**7,696**	7,268	6,375
Net cash (used in) provided by investing activities	**(6,909)**	(12,287)	(7,009)
Net cash (used in) provided by financing activities	**(3,874)**	8,093	487
	(3,087)	3,074	(147)
Effect of foreign exchange rate changes on cash and cash equivalents	**210**	(16)	94
Increase (decrease) in cash and cash equivalents	**(2,877)**	3,058	(53)

1 Includes continuing and discontinued operations.

2 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022. Refer to the Discontinued operations section for additional information.

Cash provided by operating activities[1,2]

year ended December 31 (millions of $)	2024	2023	2022
Net cash provided by operations	**7,696**	7,268	6,375
Increase (decrease) in operating working capital	**(199)**	(207)	639
Funds generated from operations	**7,497**	7,061	7,014
Specific items:			
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)	96
Current income tax (recovery) expense on Keystone regulatory decisions	**(3)**	53	27
Current income tax expense on disposition of equity interest[3]	**—**	736	—
Milepost 14 insurance expense	**—**	36	—
Settlement of Mexico prior years' income tax assessments	**—**	—	196
Keystone XL preservation and other, net of current income tax	**—**	14	20
Comparable funds generated from operations	**7,890**	7,980	7,353

1 Includes continuing and discontinued operations.

2 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022. 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 increased by $428 million in 2024 compared to 2023 primarily due to higher funds generated from operations.

Net cash provided by operations increased by $893 million in 2023 compared to 2022 primarily due to the amount and timing of working capital changes and 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 decreased by $90 million in 2024 compared to 2023 primarily due to lower comparable earnings, partially offset by increased distributions from our equity investments.

Comparable funds generated from operations increased by $627 million in 2023 compared to 2022 primarily due to higher comparable EBITDA, increased distributions from our equity investments, higher interest earned on short-term investments and net realized gains on derivatives used to manage our foreign exchange exposures, partially offset by higher interest expense.

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

year ended December 31 (millions of $)	2024	2023	2022
Capital spending[2]			
Capital expenditures	**(6,308)**	(8,007)	(6,678)
Capital projects in development	**(50)**	(142)	(49)
Contributions to equity investments	**(1,546)**	(4,149)	(2,234)
	(7,904)	(12,298)	(8,961)
Proceeds from sales of assets, net of transaction costs	**791**	33	—
Other distributions from equity investments	**549**	23	1,433
Deferred amounts and other	**(352)**	2	(41)
Keystone XL contractual recoveries	**7**	10	571
Acquisitions, net of cash acquired	**—**	(307)	—
Loans to affiliate (issued) repaid, net	**—**	250	(11)
Net cash (used in) provided by investing activities	**(6,909)**	(12,287)	(7,009)

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 net of Other distributions from equity investments of $3.1 billion in 2024 in the Canadian Natural Gas Pipelines segment (2023 - nil, 2022 - $1.2 billion in the Corporate segment). Refer to Note 5, Segmented information, Note 7, Coastal GasLink and Note 12, Loans receivable from affiliates, of our 2024 Consolidated financial statements for additional information.

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 Coastal GasLink LP and in part by higher proceeds from the sales of assets and distributions from equity investments.

Net cash used in investing activities increased from $7.0 billion in 2022 to $12.3 billion in 2023 as a result of higher contributions to equity investments primarily related to Coastal GasLink LP, as well as increased capital spending in 2023.

Capital spending[1]

The following table summarizes capital spending by segment.

year ended December 31 (millions of $)	2024	2023	2022
Canadian Natural Gas Pipelines	**2,100**	6,184	4,719
U.S. Natural Gas Pipelines	**2,575**	2,660	2,137
Mexico Natural Gas Pipelines	**2,228**	2,292	1,027
Power and Energy Solutions	**824**	1,080	894
Corporate	**50**	33	41
	7,777	12,249	8,818
Discontinued operations	**127**	49	143
	7,904	12,298	8,961

1 Capital spending reflects cash flows associated with our Capital expenditures, Capital projects in development and Contributions to equity investments net of Other distributions from equity investments of $3.1 billion in 2024 in the Canadian Natural Gas Pipelines segment (2023 - nil, 2022 - $1.2 billion in the Corporate segment). Refer to Note 5, Segmented information, Note 7, Coastal GasLink and Note 12, Loans receivable from affiliates, of our 2024 Consolidated financial statements for additional information.

Capital expenditures
Capital expenditures in 2024 were incurred primarily for the advancement of the Southeast Gateway pipeline, Columbia Gas and ANR projects, the NGTL System expansion as well as maintenance capital expenditures. Lower capital expenditures in 2024 compared to 2023 reflect reduced spending on NGTL System expansion and the Southeast Gateway pipeline.

Capital projects in development
Costs incurred during 2024 on Capital projects in development were primarily attributable to spending on projects in the Power and Energy Solutions segment.

Contributions to equity investments
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 7, Coastal GasLink, of our 2024 Consolidated financial statements for additional information.

Contributions to equity investments increased in 2023 compared to 2022 mainly due to the draws of $2,520 million on the subordinated loan by Coastal GasLink LP in 2023 which were accounted for as in-substance equity contributions.

As part of refinancing activities with the Sur de Texas joint venture, on March 15, 2022, our peso-denominated inter-affiliate loan was fully repaid upon maturity in the amount of $1.2 billion and was subsequently replaced with a new U.S. dollar-denominated inter-affiliate loan of an equivalent $1.2 billion. The Contributions to equity investments and Other distributions from equity investments with respect to these refinancing 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 the Other Information – Related party transactions section for additional information.

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.

Other distributions from equity investments
Other distributions from equity investments primarily relate to distributions from Millennium as a result of its debt financing program in 2024, as well as the return of capital from our equity investment in Iroquois.

In 2022, other distributions from equity investments primarily relates to our proportionate share of the Sur de Texas debt repayments. Subsequent to the refinancing activities with the joint venture discussed above, on July 29, 2022, the joint venture entered into an unsecured term loan agreement with third parties, the proceeds of which were used to fully repay the U.S. dollar-denominated inter-affiliate loan with TC Energy.

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
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. Refer to the Other Information – Related party transactions section for additional information.

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

year ended December 31 (millions of $)	2024	2023	2022
Notes payable issued (repaid), net	**341**	(6,299)	766
Long-term debt issued, net of issue costs	**8,089**	15,884	2,508
Long-term debt repaid	**(9,273)**	(3,772)	(1,338)
Disposition of equity interest, net of transaction costs	**419**	5,328	—
Junior subordinated notes issued, net of issue costs	**1,465**	—	1,008
Cash transferred to South Bow, net of debt settlement	**(244)**	—	—
Dividends and distributions paid	**(4,807)**	(3,052)	(3,385)
Contributions from non-controlling interests	**21**	—	—
Common shares issued, net of issue costs	**88**	4	1,905
Preferred shares redeemed	**—**	—	(1,000)
Gains (losses) on settlement of financial instruments	**27**	—	23
Net cash (used in) provided by financing activities	**(3,874)**	8,093	487

1 Includes continuing and discontinued operations.

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.

Net cash provided by financing activities increased by $7.6 billion in 2023 compared to 2022 primarily due to higher net issuances of long-term debt and repayments of notes payable, as well as the receipt of the $5.3 billion (US$3.9 billion) proceeds upon sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf.

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 2024.

(millions of Canadian $, unless otherwise noted) Company	Issue date	Type	Maturity date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	August 2024	Term Loan[1]	August 2024	US 1,242	Floating
COLUMBIA PIPELINES OPERATING COMPANY LLC					
	September 2024	Senior Unsecured Notes	October 2054	US 400	5.70%
COLUMBIA PIPELINES HOLDING COMPANY LLC					
	September 2024	Senior Unsecured Notes	October 2031	US 400	5.10%
	January 2024	Senior Unsecured Notes	January 2034	US 500	5.68%

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, which was a wholly-owned subsidiary of TC Energy at the time. Refer to the Discontinued operations section for additional information.

Long-term debt retired/repaid

The following table outlines significant long-term debt retired/repaid in 2024.

Company	Retirement/ repayment date	Type	Amount	Interest rate
(millions of Canadian $, unless otherwise noted)				
TRANSCANADA PIPELINES LIMITED				
	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
NOVA GAS TRANSMISSION LTD.				
	March 2024	Debentures	100	9.90%
ANR PIPELINE COMPANY				
	February 2024	Senior Unsecured Notes	US 125	7.38%
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.				
	Various 2024	Senior Unsecured Term Loan	US 430	Floating
	Various 2024	Senior Unsecured Revolving Credit Facility	US 185	Floating

1 In October 2024, callable notes were 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 the 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, which was a wholly-owned subsidiary of TC Energy at the time. Refer to the Discontinued operations section for additional information.

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, 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 and has been excluded from comparable measures.

For more information about long-term debt and junior subordinated notes issued and long-term debt repaid in 2024, 2023 and 2022, refer to the notes to our 2024 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 7, 2025		
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	10 million	Series 4 preferred shares
Series 4	4 million	Series 3 preferred shares
Series 5	12.1 million	Series 6 preferred shares
Series 6	1.9 million	Series 5 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
Series 11	10 million	Series 12 preferred shares
Options to buy common shares	**outstanding**	**exercisable**
	4.4 million	3.1 million

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.

For more information on preferred shares refer to the notes to our 2024 Consolidated financial statements.

Dividends

year ended December 31	2024	2023	2022
Dividends declared			
per common share[1]	$3.7025	$3.72	$3.60
per Series 1 preferred share	$0.86975	$0.86975	$0.86975
per Series 2 preferred share	$1.68134	$1.62659	$0.82611
per Series 3 preferred share	$0.4235	$0.4235	$0.4235
per Series 4 preferred share	$1.52046	$1.46703	$0.66655
per Series 5 preferred share	$0.48725	$0.48725	$0.48725
per Series 6 preferred share	$1.55132	$1.55993	$0.80668
per Series 7 preferred share	$1.36613	$0.97575	$0.97575
per Series 9 preferred share	$1.02288	$0.9405	$0.9405
per Series 10 preferred share	$0.39807	—	—
per Series 11 preferred share	$0.83775	$0.83775	$0.83775
per Series 15 preferred share	—	—	$0.30625

1 Dividends declared for fourth quarter 2024 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 the Discontinued operations section for additional information.

On February 14, 2025, we announced a quarterly dividend on our outstanding common shares of $0.85 per common share for the quarter ending March 31, 2025, which represents an increase of 3.3 per cent from TC Energy's proportionate allocation of the dividend following the Spinoff Transaction. This equates to an annual dividend of $3.40 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 7, 2025, total committed revolving and demand credit facilities were $12.2 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 2029	3.0	2.2
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2025	US 1.0	US 0.2
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2027	US 2.5	US 2.5
Columbia Pipelines Holding Company LLC[2]	Supports commercial paper program and general corporate purposes of the borrower	December 2027	US 1.5	US 1.5
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]	1.1 [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, 2024 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Notes payable	387	387	—	—	—
Long-term debt and junior subordinated notes[1]	59,319	2,955	5,968	7,416	42,980
Operating leases[2]	614	73	139	127	275
Purchase obligations and other[3]	5,024	1,407	949	526	2,142
	65,344	4,822	7,056	8,069	45,397

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 an estimated $110 million related to the transfer of pension assets to South Bow. The final transfer will be adjusted for investment returns and benefit payments from October 1, 2024, to the transfer date. Refer to the Obligations - pension and other post-retirement benefit plans section for more information.

Notes payable

Total notes payable outstanding at December 31, 2024 was $387 million (2023 – nil).

Long-term debt and junior subordinated notes

At December 31, 2024, we had $47.9 billion (2023 – $52.9 billion) of long-term debt and $11.0 billion (2023 – $10.3 billion) of junior subordinated notes.

We attempt to ladder the maturity profile of our debt. The weighted-average maturity of our junior subordinated notes and long-term debt, excluding call features is approximately 18 years.

At December 31, 2024, scheduled interest payments related to our long-term debt and junior subordinated notes were as follows:

at December 31, 2024 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Long-term debt	25,071	2,379	4,308	3,729	14,655
Junior subordinated notes	50,755	660	1,557	1,742	46,796
	75,826	3,039	5,865	5,471	61,451

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 2025 to 2038, that require the purchase of generated energy and associated environmental attributes. At December 31, 2024, 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, 2024, payments for purchase obligations and other were as follows:

at December 31, 2024 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Canadian Natural Gas Pipelines					
Transportation by others[1]	168	34	57	40	37
Transportation by others - TQM[1,2]	2,598	148	302	300	1,848
Capital spending[3]	253	246	4	2	1
U.S. Natural Gas Pipelines					
Transportation by others[1]	628	159	230	93	146
Capital spending[3]	418	314	89	15	—
Mexico Natural Gas Pipelines					
Capital spending[3]	207	207	—	—	—
Power and Energy Solutions					
Capital spending[3]	166	125	32	9	—
Other	226	30	46	40	110
Corporate					
Capital spending[3]	7	7	—	—	—
South Bow pension plan assets held in trust[4]	110	—	110	—	—
Other	243	137	79	27	—
	5,024	1,407	949	526	2,142

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 current 2024-2025 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. The final transfer will be adjusted for investment returns and benefit payments from October 1, 2024, to the transfer date. Refer to the Obligations - pension and other post-retirement benefit plans section for more information.

GUARANTEES

Sur de Texas

We and our 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. The guarantee has terms that can be renewed in June 2025, with the annual option to extend for one year periods ending in 2053.

At December 31, 2024, our share of potential exposure under the Sur de Texas pipeline guarantees was estimated to be $93 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, 2024, 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, 2024 to be approximately $59 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 2024, we made no funding contributions to our defined benefit pension plans (DB Plans), $8 million for other post-retirement benefit plans and $71 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, 2024 was $111 million (2023 – $244 million; 2022 – $322 million).

In 2025, we expect to make no contributions for the DB Plans, funding contributions of approximately $6 million for other post-retirement benefit plans and approximately $71 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 $19 million in 2024 from $20 million in 2023 primarily due to a change in Canadian post-retirement benefits.

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 the DB Plans, DC Plans and savings plans, as applicable. As part of the Spinoff Transaction, 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 will be prepared in early 2025 outlining the proposed transfer of assets from TC Energy to South Bow. The Canadian DB Plan's assets to be transferred to South Bow are subject to regulatory approval and will be transferred when approval is received. As of December 31, 2024, these assets remain in the TC Energy DB Plan trust and have been reflected as Long-term assets of discontinued operations and a corresponding obligation to South Bow has been reflected as Long-term liabilities of discontinued operations on the Consolidated balance sheet. The assets related to the U.S. DB Plan were fully transferred to South Bow as at December 31, 2024.

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 July 27, 2023, TC Energy announced plans to separate into two independent, investment-grade, publicly listed companies through the Spinoff Transaction. TC Energy shareholders voted to approve the spinoff in June 2024 and, on October 1, 2024, TC Energy completed the spinoff of its Liquids Pipelines business into the new public company, South Bow Corporation. TC Energy shareholders as of September 25, 2024 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. TC Energy common shares resumed regular way trading on the TSX and NYSE on October 2, 2024. South Bow's common shares commenced regular way trading on the TSX on October 2, 2024 and on the NYSE on October 8, 2024, under the ticker symbol SOBO. Refer to Note 4, Discontinued operations, for additional information.

Agreements

TC Energy and South Bow have executed a series of agreements to outline the parameters and guidelines that govern their ongoing relationship and to specify the separation of assets and liabilities between the two corporations. A Transition Services Agreement has been established, the primary purpose of which is to specify certain services that TC Energy will provide to South Bow, for compensation, for a period of up to two years. These services primarily include access to and support of systems that South Bow will continue to use until it has fully implemented new systems to support its business processes and warehouse management services.

As part of the Spinoff Transaction, a Tax Matters Agreement was executed to govern 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 and allocates tax liabilities in the event the Spinoff Transaction is not tax-free.

TC Energy and South Bow entered into a Separation Agreement setting 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. The Separation Agreement provides, among other things, that TC Energy will indemnify South Bow for 86 per cent of total net liabilities and costs arising from the Milepost 14 incident that occurred on the Keystone Pipeline System in December 2022 and the existing variable toll disputes on the Keystone Pipeline System (excluding any future impacts to the variable toll after October 1, 2024) subject to a maximum liability to South Bow of $30 million, in aggregate, for those two matters. Due to the inherent uncertainties of the final amounts to be settled under these indemnities, any amounts that may ultimately be payable in respect of these net liabilities to South Bow could differ materially from those reported at December 31, 2024.

Milepost 14 Incident

In December 2022, a pipeline incident occurred in Washington County, Kansas on the Keystone Pipeline System, releasing 12,937 barrels of crude oil. In June 2023, we completed the recovery of all released volumes and in October 2023, we returned Mill Creek to its natural flowing state. South Bow will maintain the commitment for long-term reclamation and environmental monitoring activities.

At December 31, 2023, we accrued a life-to-date environmental liability for the Milepost 14 incident of $794 million, before expected insurance recoveries and not including potential fines and penalties, which were indeterminable. Prior to the Spinoff Transaction, for the nine months ended September 30, 2024, amounts paid for the environmental remediation liability were $92 million (twelve months ended December 31, 2023 – $676 million). For the year ended December 31, 2024, we received $99 million (2023 – $575 million) from insurance policies related to the costs for environmental remediation.

We received insurance proceeds of $36 million related to the Milepost 14 incident that were collected from our wholly-owned captive insurance subsidiary and resulted in an impact to net income in the consolidated financial results of TC Energy. This amount has been excluded from comparable measures from discontinued operations. As part of the Separation Agreement, all future insurance recoveries will remain with TC Energy.

In fourth quarter 2024, we recorded a pre-tax expense of $37 million for our current estimate of potential incremental costs related to the Milepost 14 incident, which has been excluded from comparable measures from discontinued operations. This amount represents our 86 per cent share pursuant to the indemnity provisions in the Separation Agreement.

CER and FERC Proceedings
In 2019 and 2020, three Keystone customers initiated complaints before FERC and the CER regarding certain costs within the variable toll calculation. In December 2022, the CER issued a decision in respect of the complaint that resulted in an adjustment to previously charged tolls of $38 million, of which $27 million pertained to amounts reflected in 2021 and 2020 and was excluded from comparable measures from discontinued operations. The CER has established a proceeding to consider Keystone's compliance filing required by the decision regarding the allocation of costs for drag reducing agent in the variable toll.

On July 25, 2024, FERC released its Order on Initial Decision in respect of the complaint. For the year ended December 31, 2024, we recognized an additional pre-tax charge of $12 million (2023 – $67 million including carrying charges) with respect to the decision, which has been excluded from comparable measures from discontinued operations. On October 8, 2024, South Bow submitted a compliance filing, which is subject to final FERC approval.

Subsequent rulings from both the CER and FERC, if any, will be subject to the indemnity provisions as outlined in the Separation Agreement.

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 and have been excluded from our calculation of comparable measures from discontinued operations.

South Bow Debt
On August 28, 2024, South Bow Canadian Infrastructure Holdings Ltd. and 6297782 LLC, which were wholly-owned subsidiaries of TC Energy 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 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. Liquids Pipelines business separation costs also included interest expense of $42 million and interest income of $28 million related to senior unsecured notes and junior subordinated notes issued on August 28, 2024 and held in escrow, which have been excluded from our calculation of comparable measures from discontinued operations.

Presentation of Discontinued Operations
Upon completion of the Spinoff Transaction, the Liquids Pipelines business was accounted for as a discontinued operation. Our presentation of discontinued operations includes revenues and expenses directly attributable to the Liquids Pipelines business. As such, the results of discontinued operations excludes shared costs related to TC Energy's corporate services and governance functions that had provided support, and whose costs had been historically allocated, to the Liquids Pipelines segment. Depreciation expense related to Corporate shared assets has also been excluded from the results of discontinued operations. We have elected to allocate a portion of the interest expense incurred at the corporate level to discontinued operations. In 2024, discontinued operations represented nine months of Liquids Pipelines earnings compared to a full year of Liquids Pipelines earnings in 2023 and 2022. Prior year amounts have been recast to present the Liquids Pipelines business as a discontinued operation.

RESULTS FROM DISCONTINUED OPERATIONS

year ended December 31 (millions of $, except per share amounts)	2024[1]	2023[2]	2022[2]
Segmented earnings (losses) from discontinued operations	**716**	1,039	1,182
Interest expense	**(218)**	(297)	(288)
Interest income and other	**21**	(30)	6
Income (loss) from discontinued operations before income taxes	**519**	712	900
Income tax (expense) recovery	**(124)**	(100)	(267)
Net income (loss) from discontinued operations, net of tax	**395**	612	633
Net income (loss) per common share from discontinued operations – basic	**$0.38**	$0.60	$0.63

1 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022.
2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.

Net income (loss) from discontinued operations, net of tax in 2024 was $395 million or $0.38 per share (2023 – $612 million or $0.60 per share; 2022 – $633 million or $0.63 per share), a decrease of $217 million or $0.22 per share compared to 2023 and a decrease of $21 million or $0.03 per share in 2023 compared to 2022.

NON-GAAP MEASURES

This MD&A references non-GAAP measures, which are described on page 24. 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:

2024

- a pre-tax charge of $197 million (after-tax $167 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 (after-tax $28 million) related to our current 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 (after-tax $16 million) related to Keystone XL asset disposition and termination activities
- a pre-tax charge of $12 million (after-tax $10 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 (after-tax $52 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(after-tax $34 million) from Liquids Pipelines business separation costs related to the Spinoff Transaction
- a pre-tax accrued insurance expense of $36 million (after-tax $36 million) related to the Milepost 14 incident
- pre-tax preservation and other costs of $18 million (after-tax $14 million) related to the preservation and storage of the Keystone XL pipeline project assets
- a pre-tax recovery of $4 million (after-tax $18 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.

2022

- a pre-tax recovery of $118 million (after-tax expense $5 million) related to the net impact of a U.S. minimum tax on the 2021 Keystone XL asset impairment charge and other, partially offset by a gain on the sale of Keystone XL project assets and adjustments to the estimate for contractual and legal obligations related to termination activities
- a pre-tax charge of $27 million (after-tax $20 million) due to the CER decision on Keystone issued in December 2022 in respect of a tolling-related complaint pertaining to amounts reflected in prior periods
- pre-tax preservation and other costs of $25 million (after-tax $19 million) related to the preservation and storage of the Keystone XL pipeline project assets.

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

year ended December 31 (millions of $, except per share amounts)	2024[1]	2023[2]	2022[2]
Net income (loss) from discontinued operations, net of tax	**395**	612	633
Specific items (pre tax):			
Liquids Pipelines business separation costs	**197**	40	—
Milepost 14 incremental costs	**37**	—	—
Keystone XL asset impairment charge and other	**21**	(4)	(118)
Keystone regulatory decisions	**12**	67	27
Milepost 14 insurance expense	**—**	36	—
Keystone XL preservation and other	**—**	18	25
Risk management activities	**(67)**	34	(20)
Taxes on specific items[3]	**(30)**	(47)	114
Comparable earnings from discontinued operations	**565**	756	661
Net income (loss) per common share from discontinued operations	**$0.38**	$0.60	$0.63
Specific items (net of tax)	**0.16**	0.14	0.03
Comparable earnings per common share from discontinued operations	**$0.54**	$0.74	$0.66

1 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022.
2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.
3 Refer to page 101 for additional information.

Comparable EBITDA to comparable earnings - from discontinued operations

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[1]	2023[2]	2022[2]
Comparable EBITDA from discontinued operations	**1,145**	1,516	1,418
Depreciation and amortization	**(253)**	(332)	(322)
Interest expense included in comparable earnings[3]	**(176)**	(287)	(288)
Interest income and other included in comparable earnings[4]	**3**	6	6
Income tax (expense) recovery included in comparable earnings[5]	**(154)**	(147)	(153)
Comparable earnings from discontinued operations	**565**	756	661
Comparable earnings per common share from discontinued operations	**$0.54**	$0.74	$0.66

1 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022.

2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.

3 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.

4 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.

5 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 and a $123 million income tax expense in 2022 as part of the Keystone XL asset impairment charge and other.

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 EBITDA from discontinued operations was $98 million higher in 2023 compared to 2022 primarily due to the net effect of:

- higher contracted and uncontracted volumes across the Keystone Pipeline System
- higher contributions from the Port Neches Link Pipeline System which began operations in March 2023.

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.

Comparable earnings from discontinued operations in 2023 were $95 million or $0.08 per common share higher than in 2022, and were primarily due to changes in comparable EBITDA from discontinued operations described above.

FINANCIAL RESULTS

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 24 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	**2024**[1]	**2023**[2]	**2022**[2]
Keystone Pipeline System	**1,098**	1,453	1,356
Intra-Alberta pipelines[3]	**52**	70	71
Other	**(5)**	(7)	(9)
Comparable EBITDA from discontinued operations	**1,145**	1,516	1,418
Depreciation and amortization	**(253)**	(332)	(322)
Comparable EBIT from discontinued operations	**892**	1,184	1,096
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	118
Keystone regulatory decisions	**(12)**	(57)	(27)
Keystone XL preservation and other	**—**	(18)	(25)
Risk management activities	**67**	(34)	20
Segmented earnings (losses) from discontinued operations	**716**	1,039	1,182

1 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022.
2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.
3 Intra-Alberta pipelines includes Grand Rapids and White Spruce.

Segmented earnings from discontinued operations decreased by $323 million in 2024 compared to 2023 and decreased by $143 million in 2023 compared to 2022 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 96 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 compared to 2023 and 2022, respectively.

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 and $10 million higher in 2023 compared to 2022 primarily as a result of a stronger U.S. dollar.

OTHER INCOME STATEMENT ITEMS

Interest expense

year ended December 31 (millions of $)	2024[1]	2023[2]	2022[2]
Interest expense included in comparable earnings from discontinued operations	**(176)**	(287)	(288)
Specific items:			
Liquids Pipelines business separation costs	**(42)**	—	—
Keystone regulatory decisions	**—**	(10)	—
Interest expense from discontinued operations[3]	**(218)**	(297)	(288)

1 Represents nine months of Liquids Pipelines allocated interest expense in 2024 compared to a full year of Liquids Pipelines allocated interest expense in 2023 and 2022.
2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.
3 We have elected to allocate a portion of the interest expense incurred at the corporate level to discontinued operations. Refer to page 95 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 and was generally consistent in 2023 compared to 2022.

Interest income and other

year ended December 31 (millions of $)	2024[1]	2023[2]	2022[2]
Interest income and other included in comparable earnings from discontinued operations	**3**	6	6
Specific items:			
Liquids Pipelines business separation costs	**18**	—	—
Milepost 14 insurance expense	**—**	(36)	—
Interest income and other from discontinued operations	**21**	(30)	6

1 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022.
2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.

Interest income and other included in comparable earnings from discontinued operations was generally consistent in 2024 compared to 2023 and in 2023 compared to 2022.

Income tax (expense) recovery

year ended December 31 (millions of $)	2024[1]	2023[2]	2022[2]
Income tax (expense) recovery included in comparable earnings from discontinued operations	**(154)**	(147)	(153)
Specific items:			
Liquids Pipelines business separation costs	**30**	6	—
Milepost 14 incremental costs	**9**	—	—
Keystone XL asset impairment charge and other	**5**	14	(123)
Keystone regulatory decisions	**2**	15	7
Keystone XL preservation and other	**—**	4	6
Risk management activities	**(16)**	8	(4)
Income tax (expense) recovery from discontinued operations	**(124)**	(100)	(267)

1 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022.
2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.

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; and decreased by $6 million in 2023 compared to 2022 primarily due to higher foreign income tax rate differentials largely offset by higher 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, 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 have identified and are adopting Key Risk and Performance Indicators (KRIs) for 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

TC Energy operates a vast natural gas transmission network across North America, including 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. 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. Additionally, there is a risk of diversifying into lower-carbon opportunities before they have adequately developed commercial and regulatory constructs.

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. 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 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 company-wide Pay Equity Plan promotes fairness 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 provide valuable insights and inform targeted recommendations. Additionally, we have integrated Diversity, Equity and Inclusion 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 digital and physical 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 infrastructure.

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 and inability to provide services. 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 covering cyber and physical security. Our program is based on standards, assurance, risk management and prevention and mitigation activities. Our cyber and physical security risk preventative efforts include deploying security technology, defining secure processes, enhanced security measures for high-risk staff or facilities, and cyber and physical security awareness programs. Our mitigative activities include proactive monitoring for and responding 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 appropriate 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 risk assessments focused on 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 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 the Enterprise Risk Management Framework.

Physical Risks

Climate change has the potential to create both acute and chronic physical risks that can negatively impact our operations. Acute physical risks could include extreme weather events such as hurricanes, wildfires and floods, whereas chronic physical risks could include longer-term shifts in climate patterns, temperature, precipitation and sea levels. Due to the complex nature of climate systems, it is difficult to predict the timing, frequency or severity of such events.

The physical risks from climate change could have significant financial implications, such as unexpected costs resulting from direct damage to our assets, loss of revenues due to business interruption or indirect effects such as value chain disruption. To mitigate these physical risks, we take climate change into account in the design and evaluation of our facilities and operating assets. Our engineering standards are regularly reviewed to ensure assets continue to be designed and operated to withstand the potential impacts of climate change. 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. 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 to a lower-carbon economy. Transition risks include policy, legal, technological, market and reputational risks. These risks include, but are not limited to, 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 from transition risks 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.

Our exposure to climate-related transition risks and resulting policy changes is mitigated through our long-term, low-risk business strategy whereby much of our earnings are underpinned by regulated cost-of-service arrangements and/or long-term contracts with credit-worthy counterparties. Additional information on how we manage climate-related risks and opportunities can be found in the comprehensive TCFD and IFRS S2 alignment sections 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-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 the environment
- prevention, mitigation and management of risks related to HSSE matters, including climate change 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 and our Reconciliation Action Plan.

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

- a Sustainability Management Committee, comprised of senior leaders, that provides strategic leadership and direction on environmental, social and governance issues to integrate sustainability principles across the company's operations and projects
- an Operating Committee that is comprised of senior leaders, that is responsible for making enterprise decisions in support of safety improvements, management system governance and operational risk management.

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 2024, we spent $2.0 billion (2023[1] – $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.

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 positive 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. We complete environmental assessments for our projects, which 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 protection 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. Project plans are communicated with stakeholders and Indigenous communities, as applicable and engagement with these groups informs the environmental assessments and protection plans.

[1] Prior year results have been recast to reflect continuing operations only.

Our primary sources of risk related to the environment include:
- changing regulations and requirements coupled with increased costs related to impacts on the environment
- product releases which may cause harm to the environment (land, water and air)
- 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 TC Energy 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, 2024, accruals related to these obligations totaled $8 million (2023 – $19 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 change 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 2024, we incurred $141 million (2023 – $109 million) of expenses under existing carbon pricing programs. Across North America, there are a variety of new and evolving initiatives and policies in development at the federal, regional, state and provincial levels aimed at reducing GHG emissions. 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 climate change policies that promote environmentally and economically responsible natural resource development. Our assets in specific 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 result in higher operating costs, other expenses or capital expenditures to comply with new or more stringent regulations. The following existing jurisdictional policies and anticipated policies sections describe some of the more relevant existing and anticipated policies applicable to our business.

Existing jurisdictional policies

Canadian jurisdictions

- *Federal:* The Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (VOCs) took effect in January 2020 to reduce the oil and gas sector's methane emissions by 40 to 45 per cent below 2012 levels by 2025. Alberta, British Columbia and Saskatchewan have released their own methane regulations that replace the federal regulations for provincially-regulated assets. For federally-regulated facilities in these jurisdictions, the federal methane regulations are applicable. Compliance with the regulations requires leak detection and repair (LDAR) surveys and a reduction of vented emissions from specific equipment. Power facilities are not affected by this regulation at the current time
- *Federal:* The Federal OBPS regulation imposes carbon pricing for larger industrial facilities and sets federal benchmarks for GHG emissions for various industry sectors. This regulation applies to our assets in Manitoba. As a result of the Federal program, our assets across Canada are all subject to some type of carbon pricing and the costs under these programs are recovered through tolls. In 2024, the carbon price was $80/tonne, currently scheduled to increase by $15/tonne every year to $170/tonne in 2030
- *Federal:* On December 19, 2024, ECCC published the final Clean Electricity Regulations (CERs), targeting a net-zero electricity system 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 0 tonnes CO_2/GWh in 2050. Though there are limited compliance flexibilities, concerns persist on the CERs' potential effect on energy affordability and reliability in certain jurisdictions. We continue to evaluate the operational and financial impact on our cogeneration fleet
- *British Columbia:* As of April 2024, British Columbia implemented a provincial OBPS in place of the carbon tax, for taxing GHG emissions from fossil fuel combustion at industrial facilities. The B.C. OBPS applies to our assets in British Columbia and compliance costs are recovered through tolls. With the implementation of the B.C. OBPS, the CleanBC Industrial Incentive Program, which offered carbon tax rebates to low emitting industrial facilities, will be phased out as of 2025
- *Alberta:* In Alberta, the Technology Innovation and Emissions Reduction (TIER) regulation has been in effect since January 2020. The TIER regulation requires established industrial facilities with GHG emissions above a certain threshold to reduce their emissions below an intensity baseline. The TIER system covers all of our natural gas pipelines and Power and Energy Solutions assets in Alberta. Compliance costs with respect to our regulated Canadian natural gas pipelines are recovered through tolls. A portion of the compliance costs for the Power and Energy Solutions assets are recovered through market pricing and hedging activities
- *Québec:* Québec has a GHG cap-and-trade program under the Western Climate Initiative (WCI) GHG emissions market. In Québec, our Bécancour cogeneration plant is subject to this program as are the Canadian Mainline and TQM natural gas pipeline facilities. The provincial government allocates free emission units for a portion of Bécancour's compliance requirements. The remaining requirements are met with GHG instruments purchased at auctions or secondary markets. The costs of these emissions units are recovered through commercial contracts. For TQM and the Canadian Mainline assets in Québec, compliance instruments have been or will be purchased to comply with the WCI requirements with these compliance costs being recovered through tolls
- *Ontario:* The Federal OBPS in Ontario was replaced on January 1, 2022 by the Ontario Emissions Performance Standards (OEPS) program. The OEPS program applies to our Canadian Mainline operations in the province and costs under this program are recovered in tolls
- *Saskatchewan:* The Federal OBPS in Saskatchewan was replaced on January 1, 2023 by the Saskatchewan Output-Based Performance Standard program for pipeline transmission sector assets. The regulation applies to our Canadian Mainline and Foothills operations in the province and costs under this program are recovered in tolls.

U.S. jurisdictions

- *Federal:* On December 2, 2023, the United States Environmental Protection Agency (USEPA) released a final rule that amends and supplements 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," sets performance standards for new, modified, or reconstructed sources after December 2022 (OOOOb) and establishes emission guidelines (EGs) for existing sources prior to December 2022 (OOOOc). Under OOOOc, the states will submit their plans to meet the EGs for existing sources to the USEPA within 24 months after publication of the final rule and existing compressor stations would be required to comply with a state's new EGs no later than 36 months after the state plan is submitted to USEPA. The Methane Rule includes fugitive component LDAR requirements, a zero-emission process (pneumatic) controller standard, emission limitations for reciprocating and centrifugal compressors and a third-party reporting program facilitated by USEPA for identifying large gas release events (Super Emitter program). The OOOOb standards will apply to a relatively limited number of facilities 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 yet to be issued state EG proposals and actual compliance deadlines, which will vary based on state and/or location
- *Federal:* The USEPA "Good Neighbor Plan", effective August 2023, sets new limits for emissions of nitrogen oxides (NOx) from reciprocating internal combustion engines (RICE) by May 2026. The rule could cost TC Energy over US$500 million in mitigation measures, but Federal Circuit courts have granted stays in 12 states, including eight states in which TC Energy has affected RICE, reducing our compliance obligations pending the outcomes of these proceedings. Additionally, TC Energy, among other peer companies and industry groups, is party to ongoing legal proceedings in the D.C. Circuit and on June 27, 2024, the Supreme Court granted a nationwide emergency stay of the Rule that will last for the duration of the pending litigation in the D.C. Circuit and until the Supreme Court resolves petitions for certiorari (if any are filed). The D.C. Circuit is expected to issue a final decision in the second half of 2025. If the rule is ultimately upheld, the USEPA is expected, but not required, to provide industry with additional time beyond its May 1, 2026 compliance deadline to come into compliance
- *Federal*: USEPA finalized changes to the Greenhouse Gas Reporting Program (GHGRP) for how oil and gas sources tally and report their methane emissions (Subpart W) on May 6, 2024. The Final Rule finalizes previously proposed GHGRP amendments and also addresses USEPA's mandate, as defined in the Inflation Reduction Act (IRA), to amend Subpart W for the purposes of improving methane emission estimates associated with the IRA waste emissions charge for natural gas operations. USEPA did not finalize changes in the GHGRP for how oil and gas sources tally and report their energy consumption (Subpart B) via a final rule at this time. The Final Rule effects various changes that would add new reporting sources, modify calculation and reporting methodologies and drive more granular data collection. The Final Rule is still being assessed, but the methodological changes could result in material changes to TC Energy's publicly reported emissions
- *Federal:* The IRA was passed and signed into law in August 2022. The IRA instructed USEPA to implement a waste methane fee program by 2024 based on GHG emissions reported to USEPA as required by 40 CFR 98 Subpart W. In response, on November 8, 2024, USEPA finalized a rule to implement the methane Waste Emissions Charge ("WEC") program. TC Energy reports to Subpart W for the natural gas transmission compression, underground natural gas storage and onshore natural gas transmission pipeline industry segments. For these industry segments, the WEC imposes and collects a fee on methane emissions that exceeds 0.11 per cent of the natural gas sent for sale from the facility. The proposed fee is US$900/tonne for 2024, US$1,200/tonne for 2025 and US$1,500/tonne for 2026 reporting and forward. In an initial assessment, there would be no fee impact to TC Energy based on 2023 emissions. Over the longer term, potential WEC liability is expected to be low as U.S. natural gas facilities are anticipated to become eligible for a regulatory exemption afforded by compliance with the Methane Rule
- *California:* On September 27, 2024, California signed into law bill SB-219, which amends portions of Sections 38532 and 38533 of the California Health and Safety Code that were established in previous bills SB-253 and SB-261. SB-253 and SB-261 require public and private U.S. companies that perform certain business activities in California to disclose their GHG emissions and climate-related financial risks, respectively. Entities within the scope of SB-261 must prepare and make available on their public websites a climate-related financial risk report by January 1, 2026. Applicability to TC Energy is under evaluation

- *California:* California Air Resource Board has revised Subarticle 13 of the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. The regulation applies to three Tuscarora facilities. The revised regulation required a new LDAR monitoring plan by July 1, 2024. The regulation also now requires monitoring and repair of components less than or equal to 0.5 inch and added new requirements for remotely detected plumes
- *California:* California also has a GHG cap-and-trade program linked with Québec's program through the WCI. All Tuscarora facilities fall below the threshold requiring participation in the GHG cap-and-trade program. However, power trading activities in the state do trigger compliance thresholds. These requirements are met with GHG instruments purchased at auctions or secondary markets
- *Pennsylvania:* The Pennsylvania Department of Environmental Protection has an LDAR program for new source installations which require leak repair within 15 days of discovery
- *Ohio:* Effective March 2022, the Ohio Environmental Protection Agency (OEPA) finalized Reasonable Available Control Technologies (RACT) requirements and limitations for emissions of NOx from stationary sources in the Cleveland non-attainment area. Columbia Gas Transmission has four facilities in the Cleveland non-attainment area, with two facilities impacted by the rule. A RACT Study was submitted for one of the stations subject to the rule, outlining the steps and cost necessary to install controls by March 2025 to comply with the rule. The other facility subject to the rule is required to perform annual tune-ups to achieve compliance
- *Maryland:* Effective November 2020, the Maryland Department of the Environment (MDE) finalized a methane regulation program for new and existing natural gas facilities that includes an LDAR program, emission control and reporting requirements, plus a requirement to notify not only the MDE, but also the public of any events above a specific threshold. We have one electric-powered compressor station and associated pipeline segments impacted by this regulation
- *Washington*: In late 2022, the Washington Department of Ecology adopted the Cap-and-Invest Program (CIP), which became effective in January 2023 and established a comprehensive, market-based program to reduce carbon pollution and achieve the GHG emissions reduction goals established by the State legislature. The CIP sets a declining limit, or cap, on overall carbon emissions in the state and requires businesses to obtain allowances equal to their covered GHG emissions. Under the CIP, companies are incented to reduce emissions to avoid higher compliance costs, as the cost to obtain allowances will increase as the supply of allowances decreases over time. GTN has three impacted compressor station facilities and cost exposure under the CIP is mainly driven by throughput and fuel forecast data, as well as price volatility in the newly established CIP allowance market. As an active participant in the CIP allowance market, GTN met its first base compliance obligation for 2023 and projected obligation for 2024. Electricity imports are also covered under the CIP, however these remained below compliance thresholds in 2024
- *New York:* On February 2, 2022, the New York Department of Environmental Conservation (NY DEC) adopted 6 NYCRR Part 203, "Oil and Natural Gas Sector" with an effective date of March 3, 2022 and an initial compliance period commencing January 1, 2023. Part 203 regulates VOCs and methane emissions from the oil and gas sector. Compliance obligations include leak detection and repair at operated storage wells, compressor stations and city gate meter and regulator sites; blowdown notifications, reporting of pigging activities, as well as a baseline inventory for all assets in New York
- *Michigan:* In April 2023, the Michigan Department of Environment, Great Lakes and Energy (EGLE) published its final RACT requirements and emission limitations for major stationary sources of VOCs in specific counties of the state (2015 ozone non-attainment area). Specifically, storage vessels at two ANR compressor stations are impacted by this rule. Future storage vessels installed at compressor stations in specific counties in the state may require additional controls depending on their size and throughput.

Mexico jurisdictions

- *Federal:* The General Climate Change Law (LGCC) establishes various public policy instruments, including the National Emissions Registry and its regulations, which allow for the compilation of information on the emission of compounds and GHG emissions of the different productive sectors of the country. The LGCC defines the National Inventory of Emissions as the document that contains the estimate of anthropogenic emissions by sources and absorption by sinks in Mexico. The LGCC has the objective to reduce national emissions, through policies and programs that promote the transition to a sustainable, competitive and lower-carbon economy, including market instruments, incentives and other alternatives that improve the cost-efficiency of specific mitigation measures, reducing their economic costs and promoting competitiveness, technology transfer and the promotion of technological development. This law requires annual reporting of our GHG emissions

- *Federal:* The Government of Mexico published a regulation in 2018 that established guidelines for the prevention and control of methane emissions from the hydrocarbon sector. Companies are required to prepare a Program for the Comprehensive Prevention and Control of Methane Emissions (PPCIEM) which includes identification of sources of methane, quantification of baseline emissions and an estimate of the expected GHG emission reductions from prevention and control activities. This regulation requires the PPCIEM, through which operational and technological practices are adopted, to determine a GHG emissions intensity reduction goal that must be met within a period not exceeding six calendar years from the delivery of the PPCIEM. TC Energy developed and applied the PPCIEM to all of its facilities in Mexico in 2020
- *Federal*: The Secretariat of Environment and Natural Resources published an agreement to progressively and gradually establish an emissions commerce system in Mexico and comply with the LGCC. It functioned as a three-year pilot from 2020 to 2022 allowing the Secretariat to test the design and rules of the system, as well as evaluate its performance and then propose adjustments for a subsequent operational phase after 2022. The Emission Rights Tracking System is the electronic platform where the emission rights and compensation credits are issued, transacted and cancelled, through which the participants interact to fulfill their obligations. It has already been formally established and it is possible that we will have to participate as a company if we exceed 100 ktCO_2e in any of our systems. However, currently all our systems in Mexico are below the emissions threshold, so this instrument has not been used
- *Federal:* The Mexican accounting and sustainability standard setter, Consejo Mexicano de Normas de Información Financiera y Sostenibilidad (CINIF), published the Mexican sustainability standards (Normas de Información de Sostenibilidad or NIS) applicable to all private entities that report their financial statements under Mexican Financial Reporting Standards. The 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.

Anticipated policies

Canadian jurisdictions

- *Federal:* ECCC committed to expand on the current methane reduction regulations and released draft amendments in December 2023 to reduce the oil and gas sector methane emissions by at least 75 per cent below 2012 levels by 2030. The draft 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. TC Energy has identified several areas for improvement and clarification. We participated in the 2024 public consultation process and provided recommendations, in collaboration with industry associations. The updated regulations are expected to come into force January 1, 2027, with phased requirements through 2030. We will continue to refine our internal emissions management strategies and update our compliance plans to align with the anticipated regulatory changes
- *Federal:* On November 9, 2024, ECCC published draft Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations. The draft regulations introduce a cap-and-trade system to reduce GHG emissions from the oil and gas sector, covering upstream activities and LNG production. The initial 2030-2032 compliance period will limit emissions to 27 per cent below 2026 emissions levels with some limited compliance flexibilities. Canada would be the first major oil and gas producing country to impose such limits. Although transmission pipelines are excluded from the draft regulations, there is a possibility of cascading effects and unintended consequences to our business. The draft regulations are set to be finalized in 2025 and phased-in between 2026-2029. We continue to monitor, assess and provide feedback to ECCC, as appropriate
- *British Columbia:* The BC Energy Regulator is implementing amended regulations effective January 1, 2025 to further reduce methane emissions from the province's upstream oil and gas sector, in support of the CleanBC Roadmap to 2030 target of a 75 per cent reduction. The amendments update the Drilling and Production Regulation, Oil and Gas Processing Facility Regulation and Pipeline Regulation under the Energy Resource Activities Act. These amendments will be applicable to Coastal GasLink operations.

U.S. jurisdictions

- *Federal:* The U.S. Senate passed the PHMSA reauthorization bill, the PIPES Act of 2020, which required PHMSA to promulgate gas pipeline leak detection and repair regulations. On May 4, 2023, PHMSA released a Notice of Proposed Rulemaking (NPRM) to regulate methane emissions from new and existing gas transmission, distribution and gas gathering pipelines and underground storage and LNG facilities. PHMSA's NPRM provides limited exemption for compressor stations recognizing USEPA's Methane Rule requirements. The cost of compliance due to the proposed PHMSA regulations is subject to issuance of a final rule, which remains pending, but is expected to increase significantly due to new monitoring and repair requirements applicable to the entire natural gas transmission system. On January 17, 2025, PHMSA transmitted the final rule to the Federal Register; however, it was not published prior to the inauguration of the incoming administration. On January 20, 2025, an Executive Order was issued placing a freeze on all pending regulations not published to the Federal Register for review. At this time, the final release date of the Leak Detection and Repair Rule is uncertain. TC Energy will continue to monitor the potential outcome of the regulations following federal direction and additional industry level discussions
- *Federal:* On November 22, 2024, the USEPA proposed amendments to the Standards of Performance for new, modified, and reconstructed stationary gas turbines (under 40 CFR Part 60, Subpart KKKKa). These amendments aim to limit emissions of criteria air pollutants, particularly nitrogen oxide (NOx), by establishing size-based subcategories and recognizing distinctions between turbines operating at varying loads or capacity factors. The USEPA also proposes that the best system of emission reduction for NOX emissions includes combustion controls with post-combustion selective catalytic reduction ("SCR"). Potential impacts to TC Energy could include additional costs for installation of SCR and other ancillary costs for operational maintenance for new gas turbines that operate at low temperatures and high utilization. However, the proposed rule is still being assessed, and there is currently no effective date for the proposed rule
- *Michigan:* The Michigan Department of Environment, Great Lakes and Energy (EGLE) is currently evaluating RACT requirements and emission limitations for major stationary sources of NOx in specific counties of the state (2015 ozone non-attainment area). This will lead to the development of laws and regulations that affect TC Energy through impacted ANR and Great Lakes facilities in the state
- *New York:* The New York State Department of Environmental Conservation (DEC) and New York State Energy Research and Development Authority (NYSERDA) are developing New York's Cap-and-Invest Program (NYCI), proposed in 2023, to meet the Climate Act's GHG reduction and equity requirements. The NYCI is anticipated to set an annual cap on the amount of GHG emissions that are permitted to be emitted in the state. Publication of a draft rule was expected in early 2025, but on January 15, 2025, New York Governor Hochul announced a pause to allow for additional information gathering and enhanced engagement, such that a compliance commencement date is indeterminate at this time. NYCI will potentially impact TC Energy owned/operated assets in New York, but impacts will be further evaluated once a draft rule is published
- *Oregon:* The state has reintroduced rules for its Climate Protection Plan. The previous version was struck down by a state court on technical grounds. Like the previous rule, the draft language appears to exclude TC Energy emissions in the state, as it would exempt "Emissions from an air contamination source that is owned or operated by an interstate natural gas pipeline and that is operating under authority of a certificate of public convenience and necessity issued by the Federal Energy Regulatory Commission".

Changes to environmental remediation regulations – U.S. Jurisdictions

- *Federal:* The USEPA proposed a rule entitled, Alternate Polychlorinated Biphenyl (PCB) Extraction Methods and Amendments to PCB Cleanup and Disposal Regulations in 2021. The rule addresses a myriad of issues related to laboratory methodologies, performance-based disposal options for PCB remediation waste and emergency situations, among other proposed changes. USEPA finalized the rule in August 2023 and the rule became effective February 26, 2024. We will continue to assess the impact of the rule on future projects on a case-by-case basis, which will depend on the site- and project-specific considerations and remediation efforts on each project.

In addition to the policies above, there are new mandatory climate-related disclosure requirements being issued in jurisdictions in which we operate. These disclosure requirements may impact how we report our climate-related risks and opportunities, strategy, risk management and GHG emission metrics and targets. We continue to monitor these developments and progress activities in anticipation of these new requirements.

Other sustainability related regulations

- In 2024, the Government of Canada passed Bill C-59 including a provision to amend the Competition Act targeting unsubstantiated claims about the environmental benefits of products or business activities, commonly known as "greenwashing." The Bill C-59 greenwashing provision affects a wide range of industries and companies, including TC Energy. Following the passage of Bill C-59, the Competition Bureau of Canada conducted a public consultation on implementation guidance and enforcement of the greenwashing provision. TC Energy participated in the public consultation process and will continue to seek clarity on how the new legislation will be interpreted and applied.

There are other sustainability-related disclosure requirements being issued in jurisdictions in which we operate. While these disclosure requirements do not necessarily apply to us, they may impact how we report on non-climate related sustainability risks, opportunities, strategies, governance and incidents. We continue to monitor these developments and progress activities related to these new and anticipated requirements.

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, cross-currency interest rate swaps and foreign exchange options, 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 any impairment, which is recognized in Plant operating costs and other. At December 31, 2024 and 2023, we had no significant credit risk concentrations, with the exception of the CFE, which represents approximately 33 per cent of the 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 recovery of $22 million for the year ended December 31, 2024 on the expected credit loss provision before tax recognized on TGNH net investment in leases and certain contract assets in Mexico (2023 – $80 million recovery). Other than the expected credit loss provision noted above, we had no significant credit losses at December 31, 2024 and 2023. Refer to Note 28, Risk management and financial instruments, of our 2024 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. With the potential exception of the matters discussed in Note 31, Commitments, contingencies and guarantees, of our 2024 Consolidated financial statements, it is the opinion of management that the ultimate resolution of such proceedings and actions will not have a material impact on our consolidated financial position or results of operations. The claims discussed in Note 31, Commitments, contingencies and guarantees, are material and there is a reasonable possibility of loss; however, they have not been assessed as probable and a reasonable estimate of loss cannot be made.

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, 2024, 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 annual 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, 2024, 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, 2024, the internal control over financial reporting was effective.

Our internal control over financial reporting as of December 31, 2024 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included in our 2024 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 2024 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.

On October 1, 2024, we completed the Spinoff Transaction. In connection with the Spinoff Transaction, the internal controls associated with the Liquids Pipelines business were transferred to South Bow. We are contractually obligated to maintain adequate controls post-spinoff for the provision of services under the Transition Services Agreement.

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 2024 Consolidated financial statements for additional information.

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, current valuation multiples and discount rates, 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.

In the determination of the fair value utilized in the quantitative goodwill impairment test performed in 2023 for the Columbia reporting unit, we performed a discounted cash flow analysis using projections of future cash flows and applied a risk-adjusted discount rate and terminal value multiple which involved significant estimates and judgments. It was determined that the fair value of the Columbia reporting unit exceeded its carrying value, including goodwill. Although goodwill was not impaired, the estimated fair value in excess of the carrying value was less than 10 per cent. There is a risk that reductions in future cash flow forecasts and adverse changes in other key assumptions could result in a future impairment of a portion of the goodwill balance relating to Columbia.

In March 2022, an impairment loss was recognized for the excess carrying value over the estimated fair value of our Great Lakes reporting unit. There is a risk that reductions in future cash flow forecasts and adverse changes in other key assumptions could result in future impairment of the remaining goodwill balance.

Qualitative goodwill impairment indicators

As part of the annual goodwill impairment assessment at December 31, 2024, we evaluated qualitative factors impacting the fair value of the underlying reporting units. It was determined that it was more likely than not that the fair value of these reporting units exceeded their carrying amounts, including goodwill.

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 ratepayers 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 $)	2024	2023
Other current assets	**347**	589
Other long-term assets	**122**	155
Accounts payable and other	**(507)**	(415)
Other long-term liabilities	**(209)**	(106)
	(247)	223

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, 2024 (millions of $)	Total fair value	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Derivative instruments held for trading	(122)	(147)	3	25	(3)
Derivative instruments in hedging relationships	(125)	(15)	(35)	(42)	(33)
	(247)	(162)	(32)	(17)	(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 $)	2024	2023	2022
Derivative Instruments Held for Trading[1]			
Unrealized gains (losses) in the year			
Commodities	**(71)**	132	(11)
Foreign exchange	**(266)**	246	(149)
Interest rate	**(71)**	—	—
Realized gains (losses) in the year			
Commodities	**199**	192	46
Foreign exchange	**(152)**	155	(2)
Interest rate	**29**	—	—
Derivative Instruments in Hedging Relationships[2]			
Realized gains (losses) in the year			
Commodities	**33**	(2)	(73)
Interest rate	**(52)**	(43)	(3)

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. Realized and unrealized gains (losses) on foreign exchange held-for-trading derivative instruments are included on a net basis in Foreign exchange (gains) losses, net in the Consolidated statement of income. Realized and unrealized gains (losses) on interest rate derivatives are included on a net basis in Interest expense in the Consolidated statement of income.

2 In 2024, unrealized gains of $6 million were reclassified to Net Income (loss) from AOCI related to discontinued cash flow hedges (2023 and 2022 – 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 28, Risk management and financial instruments, of our 2024 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 have been contracted to develop, construct 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. This repayment reduced our funding commitment under the subordinated loan agreement to $228 million at December 31, 2024.

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.

Refer to Note 7, Coastal GasLink, of our 2024 Consolidated financial statements for additional information about Coastal GasLink LP related party transactions.

Sur de Texas

We hold a 60 per cent equity interest in a joint venture with IEnova to own the Sur de Texas pipeline, for which we are the operator. In 2017, we entered into a MXN$21.3 billion unsecured revolving credit facility with the joint venture, which bore interest at a floating rate and was fully repaid upon maturity on March 15, 2022 in the amount of $1.2 billion.

Our Consolidated statement of income reflects the related interest income and foreign exchange impact on this loan receivable until its repayment on March 15, 2022, which were fully offset upon consolidation with corresponding amounts included in our proportionate share of Sur de Texas equity earnings as follows:

year ended December 31 (millions of $)	**2024**	**2023**	**2022**	**Affected line item in the Consolidated statement of income**
Interest income[1]	—	—	19	Interest income and other
Interest expense[2]	—	—	(19)	Income (loss) from equity investments
Foreign exchange losses[1]	—	—	(28)	Foreign exchange (gains) losses, net
Foreign exchange gains[1]	—	—	28	Income (loss) from equity investments

1 Included in our Corporate segment.
2 Included in our Mexico Natural Gas Pipelines segment.

On March 15, 2022, as part of refinancing activities with the Sur de Texas joint venture, the peso-denominated inter-affiliate loan discussed above was replaced with a new U.S. dollar-denominated inter-affiliate loan from us of an equivalent $1.2 billion (US$938 million) with a floating interest rate. On July 29, 2022, the Sur de Texas joint venture entered into an unsecured term loan agreement with third parties, the proceeds of which were used to fully repay the U.S. dollar-denominated inter-affiliate loan with TC Energy.

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 2024 Consolidated financial statements.

QUARTERLY RESULTS

Selected quarterly consolidated financial data

2024 (millions of $, except per share amounts)	Fourth	Third[1]	Second[1]	First[1]
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	1,349	793	988
from discontinued operations[2]	(98)	108	170	215
Comparable earnings[3]	**1,094**	**1,074**	**978**	**1,284**
from continuing operations	1,094	905	811	1,055
from discontinued operations[2]	—	169	167	229
Share statistics:				
Net income (loss) per common share – basic	**$0.94**	**$1.40**	**$0.93**	**$1.16**
from continuing operations	$1.03	$1.30	$0.77	$0.95
from discontinued operations[2]	($0.09)	$0.10	$0.16	$0.21
Comparable earnings per common share[3]	**$1.05**	**$1.03**	**$0.94**	**$1.24**
from continuing operations	$1.05	$0.87	$0.78	$1.02
from discontinued operations[2]	—	$0.16	$0.16	$0.22
Dividends declared per common share[4]	**$0.8225**	**$0.96**	**$0.96**	**$0.96**

1 Prior quarter results have been recast to reflect the split between continuing and discontinued operations.
2 Represents nine months of Liquids Pipelines earnings in 2024.
3 Additional information on the most directly comparable GAAP measure can be found on page 24.
4 Dividends declared in fourth quarter 2024 reflect TC Energy's proportionate allocation following the Spinoff Transaction. Refer to the Discontinued operations section for additional information.

2023[1] (millions of $, except per share amounts)	Fourth	Third	Second	First
Revenues from continuing operations	3,504	3,225	3,148	3,390
Net income (loss) attributable to common shares	1,463	(197)	250	1,313
from continuing operations	1,249	(325)	76	1,217
from discontinued operations[2]	214	128	174	96
Comparable earnings[3]	1,403	1,035	981	1,233
from continuing operations	1,192	848	767	1,089
from discontinued operations[2]	211	187	214	144
Share statistics:				
Net income (loss) per common share – basic	$1.41	($0.19)	$0.24	$1.29
from continuing operations	$1.20	($0.31)	$0.07	$1.19
from discontinued operations[2]	$0.21	$0.12	$0.17	$0.10
Comparable earnings per common share[3]	$1.35	$1.00	$0.96	$1.21
from continuing operations	$1.15	$0.82	$0.75	$1.07
from discontinued operations[2]	$0.20	$0.18	$0.21	$0.14
Dividends declared per common share	$0.93	$0.93	$0.93	$0.93

1 Prior year results have been recast to reflect the split between continuing and discontinued operations.
2 Represents a full year of Liquids Pipelines earnings in 2023.
3 Additional information on the most directly comparable GAAP measure can be found on page 24.

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. Prior year results have been recast to reflect the split between continuing and discontinued operations. Discontinued operations reflect nine months of Liquids Pipelines earnings for the year ended December 31, 2024 compared to a full year of Liquids earnings in 2023. 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 24 for more information on non-GAAP measures we use.

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

- a pre-tax net gain on debt extinguishment of $228 million (after-tax $178 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 (after-tax $153 million) on the peso-denominated intercompany loan between TCPL and TGNH, net of non-controlling interest
- a pre-tax recovery of $3 million (after-tax $2 million) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico, net of non-controlling interest
- 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 (after-tax $27 million) related to development costs incurred on Project Tundra, a next-generation technology carbon capture and storage project, following our decision to end our collaboration on the project
- a pre-tax expense of $9 million (after-tax $7 million) related to Focus Project costs.

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

- a pre-tax gain of $572 million (after-tax $456 million) related to the sale of PNGTS which was completed on August 15, 2024
- pre-tax unrealized foreign exchange losses, net, of $52 million (after-tax $52 million) on the peso-denominated intercompany loan between TCPL and TGNH, net of non-controlling interest
- a pre-tax expense of $5 million (after-tax $4 million) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico, net of non-controlling interest
- a pre-tax expense of $5 million (after-tax $3 million) related to Focus Project costs.

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

- a pre-tax gain of $48 million (after-tax $63 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 (after-tax $3 million) on the peso-denominated intercompany loan between TCPL and TGNH, net of non-controlling interest
- a pre-tax recovery of $3 million (after-tax $2 million) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico, net of non-controlling interest
- pre-tax costs of $10 million (after-tax $42 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 (after-tax $55 million) on the peso-denominated intercompany loan between TCPL and TGNH
- a pre-tax recovery of $21 million (after-tax $15 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 (after-tax $26 million) related to a non-recurring third-party settlement
- a pre-tax expense of $10 million (after-tax $8 million) related to Focus Project costs.

In fourth quarter 2023, comparable earnings from continuing operations also excluded:

- a $74 million income tax recovery related to a revised assessment of the valuation allowance and non-taxable capital losses on our equity investment in Coastal GasLink LP
- pre-tax unrealized foreign exchange losses, net of $55 million (after-tax $55 million) on the peso-denominated intercompany loan between TCPL and TGNH
- a pre-tax expense of $36 million (after-tax $25 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 $15 million (after-tax $9 million) related to Focus Project costs.

In third quarter 2023, comparable earnings from continuing operations also excluded:

- a pre-tax impairment charge of $1,244 million (after-tax $1,179 million) related to our equity investment in Coastal GasLink LP
- a pre-tax expense of $18 million (after-tax $14 million) related to Focus Project costs
- pre-tax net unrealized foreign exchange gains, net of $20 million (after-tax $20 million) on the peso-denominated intercompany loan between TCPL and TGNH
- a pre-tax recovery of $1 million (nil after tax) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico.

In second quarter 2023, comparable earnings from continuing operations also excluded:

- a pre-tax impairment charge of $843 million (after-tax $809 million) related to our equity investment in Coastal GasLink LP
- a pre-tax expense of $32 million (after-tax $25 million) related to Focus Project costs
- pre-tax unrealized foreign exchange losses, net of $9 million (after-tax $9 million) on the peso-denominated intercompany loan between TCPL and TGNH
- a pre-tax recovery of $11 million (after-tax $8 million) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico.

In first quarter 2023, comparable earnings from continuing operations also excluded:

- a pre-tax recovery of $104 million (after-tax $72 million) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico
- a pre-tax impairment charge of $13 million (after-tax $29 million) related to our equity investment in Coastal GasLink LP.

FOURTH QUARTER 2024 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	2024	2023[1]
Canadian Natural Gas Pipelines	**506**	692
U.S. Natural Gas Pipelines	**918**	955
Mexico Natural Gas Pipelines	**214**	150
Power and Energy Solutions	**276**	263
Corporate	**(16)**	(34)
Total segmented earnings (losses)	**1,898**	2,026
Interest expense	**(679)**	(777)
Allowance for funds used during construction	**233**	132
Foreign exchange gains (losses), net	**(69)**	89
Interest income and other	**120**	119
Income (loss) from continuing operations before income taxes	**1,503**	1,589
Income tax (expense) recovery from continuing operations	**(223)**	(188)
Net income (loss) from continuing operations	**1,280**	1,401
Net income (loss) from discontinued operations, net of tax[2]	**(98)**	214
Net income (loss)	**1,182**	1,615
Net (income) loss attributable to non-controlling interests	**(183)**	(128)
Net income (loss) attributable to controlling interests	**999**	1,487
Preferred share dividends	**(28)**	(24)
Net income (loss) attributable to common shares	**971**	1,463
Net income (loss) per common share – basic	**0.94**	1.41
from continuing operations	**$1.03**	$1.20
from discontinued operations[2]	**($0.09)**	$0.21

1 Prior year results have been recast to reflect the split between continuing and discontinued operations.
2 The Liquids Pipelines business was accounted for as a discontinued operation starting October 1, 2024. Refer to the Discontinued operations section for additional information.

three months ended December 31 (millions of $)	2024	2023[1]
Amounts attributable to common shares		
Net income (loss) from continuing operations	**1,280**	1,401
Net income (loss) attributable to non-controlling interest	**(183)**	(128)
Net income (loss) attributable to controlling interests from continuing operations	**1,097**	1,273
Preferred share dividends	**(28)**	(24)
Net income (loss) attributable to common shares from continuing operations	**1,069**	1,249
Net income (loss) from discontinued operations, net of tax[2]	**(98)**	214
Net income (loss) attributable to common shares	**971**	1,463

1 Prior year results have been recast to reflect the split between continuing and discontinued operations.
2 The Liquids Pipelines business was accounted for as a discontinued operation starting October 1, 2024. Refer to the Discontinued operations section for additional information.

Net income (loss) attributable to common shares from continuing operations decreased by $180 million or $0.17 per common share for the three months ended December 31, 2024 compared to the same period in 2023. The decrease is primarily due to the net effect of the specific items mentioned above.

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)	2024	2023[1]
Net income (loss) attributable to common shares from continuing operations	**1,069**	1,249
Specific items (pre tax):		
Net gain on debt extinguishment[2]	**(228)**	—
Foreign exchange (gains) losses, net – intercompany loan[3]	**(143)**	55
Expected credit loss provision on net investment in leases and certain contract assets in Mexico[4]	**(3)**	36
Project Tundra impairment charge	**36**	—
Focus Project costs[5]	**9**	15
Bruce Power unrealized fair value adjustments	**(2)**	(7)
Risk management activities[6]	**301**	(91)
Taxes on specific items[7]	**55**	(65)
Comparable earnings from continuing operations	**1,094**	1,192
Net income (loss) per common share from continuing operations	**$1.03**	$1.20
Specific items (net of tax)	**0.02**	(0.05)
Comparable earnings per common share from continuing operations	**$1.05**	$1.15

1 Prior year results have been recast to reflect continuing operations only.

2 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 the Financial condition section for additional information.

3 In 2023, TCPL and TGNH became party to an unsecured revolving credit facility. The loan receivable and loan payable are eliminated upon consolidation; however, due to differences in the currency that each entity reports its financial results, there is an impact to net income reflecting the revaluation and translation of the loan receivable and loan payable to TC Energy's reporting currency. As the amounts do not accurately reflect what will be realized at settlement, we exclude from comparable measures the unrealized foreign exchange gains and losses on the loan receivable, as well as the corresponding unrealized foreign exchange gains and losses on the loan payable, net of non-controlling interest.

4 In 2022, TGNH and the CFE executed agreements which consolidate several natural gas pipelines under one TSA. As this TSA contains a lease, we have recognized amounts in net investment in leases on our Consolidated balance sheet. As required by U.S. GAAP, 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 28, Risk management and financial instruments, for additional information.

5 In 2022, we launched the Focus Project with benefits in the form of enhanced safety, productivity and cost-effectiveness expected to be realized in the future. Beginning in 2023, we recognized expenses in Plant operating costs and other, for external consulting and severance, some of which are not recoverable through regulatory and commercial tolling structures. Refer to the Corporate – Significant events section for additional information.

6

three months ended December 31 (millions of $)	2024	2023
U.S. Natural Gas Pipelines	**(37)**	(29)
Canadian Power	**17**	(6)
U.S. Power	**(2)**	4
Natural Gas Storage	**(20)**	18
Interest rate	**(71)**	—
Foreign exchange	**(188)**	104
	(301)	91
Income tax attributable to risk management activities	**72**	(24)
Total unrealized gains (losses) from risk management activities	**(229)**	67

7 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)	2024	2023[1]
Comparable EBITDA from continuing operations		
Canadian Natural Gas Pipelines	**851**	1,034
U.S. Natural Gas Pipelines	**1,200**	1,225
Mexico Natural Gas Pipelines	**234**	208
Power and Energy Solutions	**341**	266
Corporate	**(7)**	(18)
Comparable EBITDA from continuing operations	**2,619**	2,715
Depreciation and amortization	**(639)**	(632)
Interest expense included in comparable earnings	**(836)**	(777)
Allowance for funds used during construction	**233**	132
Foreign exchange gains (losses), net included in comparable earnings	**(44)**	40
Interest income and other	**120**	119
Income tax (expense) recovery included in comparable earnings	**(168)**	(253)
Net (income) loss attributable to non-controlling interests included in comparable earnings	**(163)**	(128)
Preferred share dividends	**(28)**	(24)
Comparable earnings from continuing operations	**1,094**	1,192
Comparable earnings per common share from continuing operations	**$1.05**	$1.15

1 Prior year results have been recast to reflect continuing operations only.

Comparable EBITDA from continuing operations

Fourth quarter 2024 versus fourth quarter 2023

Comparable EBITDA from continuing operations decreased by $96 million for the three months ended December 31, 2024 compared to the same period in 2023 primarily due to the net effect of the following:

- decreased EBITDA in Canadian Natural Gas Pipelines mainly due to lower earnings from Coastal GasLink related to the recognition of a $200 million incentive payment in 2023, partially offset by higher flow-through costs on the NGTL System
- decreased U.S. dollar-denominated EBITDA from U.S. Natural Gas Pipelines mainly as a result of the sale of PNGTS, which was completed on August 15, 2024, lower realized earnings related to our U.S. natural gas marketing business primarily due to lower margins and lower equity earnings from Iroquois, partially offset by incremental earnings from growth projects placed in service and additional contract sales
- increased Power and Energy Solutions EBITDA primarily attributable to higher contributions from Bruce Power due to higher generation, a higher contract price and lower outage costs, partially offset by decreased Canadian Power earnings primarily due to lower realized power prices, net of lower natural gas fuel costs
- increased U.S. dollar-denominated EBITDA from Mexico Natural Gas Pipelines primarily due to higher equity earnings from Sur de Texas as a result of the impact of peso-denominated financial exposure and lower income tax expense, partially offset by lower earnings in TGNH primarily related to higher operating costs
- 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. U.S. dollar-denominated comparable EBITDA decreased by US$27 million compared to 2023 and was translated at a rate of 1.40 in 2024 versus 1.36 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

Fourth quarter 2024 versus fourth quarter 2023

Comparable earnings from continuing operations decreased by $98 million or $0.10 per common share for the three months ended December 31, 2024 compared to the same period in 2023 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher interest expense primarily due to lower capitalized interest, interest expense allocated to discontinued operations in 2023 and lower interest rates on increased levels of short-term borrowing, partially offset by long-term debt repayments, net of issuances and realized gains from risk management activities used to manage our interest rate risk
- higher AFUDC primarily due to spending on the Southeast Gateway pipeline project, partially offset by projects placed in service
- 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
- lower income tax expense due to lower earnings subject to income tax and Mexico foreign exchange exposure, 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 sale of a 13.01 per cent non-controlling equity interest in TGNH to the CFE completed in second quarter 2024, lower taxable earnings from the Texas Wind Farms and a stronger U.S. dollar on translation of U.S. dollar-denominated net income attributable to non-controlling interests.

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, 2024 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$)	**2024**	**2023**[1]
Comparable EBITDA		
U.S. Natural Gas Pipelines	**859**	900
Mexico Natural Gas Pipelines	**167**	153
	1,026	1,053
Depreciation and amortization	**(191)**	(192)
Interest expense on long-term debt and junior subordinated notes	**(440)**	(473)
Interest expense allocated to discontinued operations	**—**	47
Allowance for funds used during construction	**159**	81
Net (income) loss attributable to non-controlling interests included in comparable earnings and other	**(125)**	(92)
	429	424
Average exchange rate - U.S. to Canadian dollars	**1.40**	1.36

1 Prior year results have been recast to reflect continuing operations only.

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, 2024	**20.87**
December 31, 2023	16.91
December 31, 2022	19.50

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 $)	**2024**	**2023**
Comparable EBITDA - Mexico Natural Gas Pipelines[1]	**30**	(16)
Foreign exchange gains (losses), net included in comparable earnings	**(21)**	64
Income tax (expense) recovery included in comparable earnings	**27**	(38)
Net (income) loss attributable to non-controlling interests included in comparable earnings[2]	**(3)**	—
	33	10

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 decreased by $186 million for the three months ended December 31, 2024 compared to the same period in 2023.

Net income for the NGTL System decreased by $8 million for the three months ended December 31, 2024 compared to the same period in 2023 mainly due to incentive losses. The NGTL System was operating under the 2020-2024 Revenue Requirement Settlement which included an approved ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provided the NGTL System the opportunity to increase depreciation rates if tolls fall below specified levels and an incentive mechanism for certain operating costs where variances from projected amounts are shared with our customers.

Net income for the Canadian Mainline increased by $7 million for the three months ended December 31, 2024 compared to the same period in 2023 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 decreased by $183 million for the three months ended December 31, 2024 compared to the same period in 2023 due to the net effect of:

- earnings from Coastal GasLink in 2023 related to the recognition of a $200 million incentive payment upon meeting certain milestones
- higher flow-through income taxes and depreciation on the NGTL System, partially offset by incentive losses.

Depreciation and amortization for the three months ended December 31, 2024 was largely consistent with the same period in 2023.

U.S. Natural Gas Pipelines

U.S. Natural Gas Pipelines segmented earnings decreased by $37 million for the three months ended December 31, 2024 compared to the same period in 2023 and included unrealized gains and losses from changes in the fair value of derivatives related to our U.S. natural gas marketing business, which have been excluded from our calculation of comparable EBITDA and comparable EBIT.

A stronger U.S. dollar for the three months ended December 31, 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.

Comparable EBITDA for U.S. Natural Gas Pipelines decreased by US$41 million for the three months ended December 31, 2024 compared to the same period in 2023 and was primarily due to the net effect of:

- decreased earnings as a result of the sale of our 61.7 per cent equity interest in PNGTS, which was completed on August 15, 2024
- lower realized earnings related to our U.S. natural gas marketing business, primarily due to lower margins
- lower equity earnings from Iroquois
- decreased earnings due to higher operational costs, reflective of increased system utilization across our footprint
- incremental earnings from growth and modernization projects placed in service, as well as increased earnings from additional contract sales on ANR.

Depreciation and amortization for the three months ended December 31, 2024 was largely consistent with the same period in 2023.

Mexico Natural Gas Pipelines

Mexico Natural Gas Pipelines segmented earnings increased by $64 million for the three months ended December 31, 2024 compared to the same period in 2023 and included an unrealized recovery of $3 million (2023 – unrealized loss of $36 million), on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico, which has been excluded from our calculation of comparable EBITDA and comparable EBIT. Refer to Note 28, Risk management and financial instruments, of our 2024 Consolidated financial statements for additional information.

A stronger U.S. dollar for the three months ended December 31, 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$14 million for the three months ended December 31, 2024 compared to the same period in 2023 due to the net effect of:

- higher equity earnings in Sur de Texas primarily due to the foreign exchange impacts upon the revaluation of peso-denominated liabilities as a result of a weaker Mexican peso and lower income tax expense mainly due to foreign exchange impacts. We use foreign exchange derivatives to manage this exposure, the impact of which is recognized in Foreign exchange (gains) losses, net in the Consolidated statement of income. Refer to the Foreign exchange section for additional information
- lower earnings in TGNH primarily related to higher operating costs from integrity activities performed in fourth quarter 2024.

Depreciation and amortization was consistent for the three months ended December 31, 2024 compared to the same period in 2023.

Power and Energy Solutions

Power and Energy Solutions segmented earnings increased by $13 million for the three months ended December 31, 2024 compared to the same period in 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 of $36 million related to development costs incurred on Project Tundra, a next-generation technology carbon capture and storage project, following our decision to end our collaboration on the project
- 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 increased by $75 million for the three months ended December 31, 2024 compared to the same period in 2023 primarily due to the net effect of:

- improved contributions from Bruce Power primarily due to increased generation, a higher contract price and lower outage costs, partially offset by increased operating and depreciation costs. Refer to the Bruce Power section for additional information
- decreased Canadian Power financial results primarily from lower realized power prices, net of lower natural gas fuel costs.

Depreciation and amortization was consistent for the three months ended December 31, 2024 compared to the same period in 2023.

Corporate

Corporate segmented losses decreased by $18 million for the three months ended December 31, 2024 compared to the same period in 2023. Corporate segmented losses included a pre-tax charge of $9 million for the three months ended December 31, 2024 (2023 – $15 million) related to Focus Project costs, which has been excluded from our calculation of comparable EBITDA and comparable EBIT.

Comparable EBITDA for Corporate was a loss of $7 million for the three months ended December 31, 2024 compared to a loss of $18 million for the same period in 2023 and includes shared costs in 2023 related to TC Energy's corporate services and governance functions that were not allocated to discontinued operations in accordance with U.S. GAAP. Refer to the Discontinued operations section for additional information.

Depreciation and amortization for the three months ended December 31, 2024 was largely consistent with the same period in 2023.

QUARTERLY RESULTS - FROM DISCONTINUED OPERATIONS

Factors affecting financial information by quarter

The quarterly results section references non-GAAP measures, which are described on page 24. 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 2024, comparable earnings from discontinued operations also excluded:

- a pre-tax charge of $85 million (after-tax $72 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 (after-tax $28 million) related to our current 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 (after-tax $2 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 (after-tax $56 million) due to Liquids Pipelines business separation costs related to the Spinoff Transaction
- a pre-tax expense of $21 million (after-tax $16 million) related to Keystone XL asset disposition and termination activities
- a pre-tax charge of $15 million (after-tax $12 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 (after-tax $26 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 (after-tax $13 million) due to Liquids Pipelines business separation costs related to the Spinoff Transaction.

In fourth quarter 2023, comparable earnings from discontinued operations also excluded:

- a pre-tax charge of $25 million (after-tax $23 million) from Liquids Pipelines business separation costs related to the Spinoff Transaction
- pre-tax preservation and other costs of $5 million (after-tax $4 million) related to the preservation and storage of the Keystone XL pipeline project assets
- pre-tax carrying charges of $5 million (after-tax $4 million) as a result of a charge related to the FERC Administrative Law Judge initial decision on Keystone issued in February 2023 in respect of a tolling-related complaint pertaining to amounts recognized in prior periods
- a pre-tax recovery of $4 million (after-tax $18 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.

In third quarter 2023, comparable earnings from discontinued operations also excluded:

- a pre-tax charge of $15 million (after-tax $11 million) due to Liquids Pipelines business separation costs related to the Spinoff Transaction
- pre-tax preservation and other costs for Keystone XL pipeline project assets of $3 million (after-tax $2 million).

In second quarter 2023, comparable earnings from discontinued operations also excluded:

- a $36 million pre-tax (after-tax $36 million) accrued insurance expense related to the Milepost 14 incident
- pre-tax preservation and other costs for Keystone XL pipeline project assets of $5 million (after-tax $4 million).

In first quarter 2023, comparable earnings from discontinued operations also excluded:

- a $62 million pre-tax (after-tax $48 million) charge as a result of the FERC Administrative Law Judge initial decision on Keystone issued in February 2023 in respect of a tolling-related complaint pertaining to amounts recognized from 2018 to 2022 which consists of a one-time pre-tax charge of $57 million (after-tax $44 million) and accrued pre-tax carrying charges of $5 million (after-tax $4 million)
- pre-tax preservation and other costs for Keystone XL pipeline project assets of $5 million (after-tax $4 million).

Results from discontinued operations

three months ended December 31 (millions of $, except per share amounts)	2024[1]	2023[2]
Segmented earnings (losses) from discontinued operations	**(109)**	301
Interest expense	**—**	(68)
Interest income and other	**(10)**	2
Income (loss) from discontinued operations before income taxes	**(119)**	235
Income tax (expense) recovery	**21**	(21)
Net income (loss) from discontinued operations, net of tax	**(98)**	214
Net income (loss) per common share from discontinued operations - basic	**($0.09)**	$0.21

1 The Liquids Pipelines business was accounted for as a discontinued operation starting October 1, 2024. Refer to the Discontinued operations section for additional information.
2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.

Net income (loss) from discontinued operations, net of tax was a net loss of $98 million or loss of $0.09 per share for the three months ended December 31, 2024 compared to net income of $214 million or $0.21 per share for the same period in 2023. The decrease reflects the completion of the Spinoff Transaction on October 1, 2024 and the net effect of the specific items mentioned above.

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)	2024[1]	2023[2]
Net income (loss) from discontinued operations, net of tax	**(98)**	214
Specific items (pre tax):		
Liquids Pipelines business separation costs	**85**	25
Milepost 14 incremental costs	**37**	—
Keystone regulatory decisions	**(3)**	5
Keystone XL preservation and other	**—**	5
Keystone XL asset impairment charge and other	**—**	(4)
Risk management activities	**—**	(20)
Taxes on specific items[3]	**(21)**	(14)
Comparable earnings from discontinued operations	**—**	211
Net income (loss) per common share from discontinued operations	**($0.09)**	$0.21
Specific items (net of tax)	**0.09**	(0.01)
Comparable earnings per common share from discontinued operations	**—**	$0.20

1 The Liquids Pipelines business was accounted for as a discontinued operation starting October 1, 2024. Refer to the Discontinued operations section for additional information.
2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.
3 Refer to page 101 for additional information.

Comparable EBITDA to comparable earnings - from discontinued operations

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.

three months ended December 31 (millions of $, except per share amounts)	2024[1]	2023[2]
Comparable EBITDA from discontinued operations	—	392
Depreciation and amortization	—	(85)
Interest expense included in comparable earnings[3]	—	(63)
Interest income and other included in comparable earnings[4]	—	2
Income tax (expense) recovery included in comparable earnings[5]	—	(35)
Comparable earnings from discontinued operations	—	211
Comparable earnings per common share from discontinued operations	—	$0.20

1 The Liquids Pipelines business was accounted for as a discontinued operation starting October 1, 2024. Refer to the Discontinued operations section for additional information.
2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.
3 Excludes pre-tax carrying charges of $5 million for the three months ended December 31, 2023 as a result of a 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.
4 Excludes pre-tax Liquids Pipelines business separation costs of $10 million related to insurance provisions for the three months ended December 31, 2024.
5 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 fourth quarter 2023 on the Keystone XL asset impairment charge and other related to the termination of the Keystone XL pipeline project.

Comparable EBITDA and comparable earnings from discontinued operations

Comparable EBITDA and comparable earnings from discontinued operations were nil for three months ended December 31, 2024 compared to comparable EBITDA of $392 million and comparable earnings of $211 million or $0.20 per common share for the same period in 2023. The decrease reflects the completion of the Spinoff Transaction on October 1, 2024.

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)
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 2024 to that in 2023, and highlights significant changes between 2023 and 2022. 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, 2024, 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 13, 2025

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, 2024 and 2023, the related consolidated statements of income, comprehensive income, cash flows, and equity for each of the years in the three-year period ended December 31, 2024, 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, 2024 and 2023, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2024, 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, 2024, 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 13, 2025 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 Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the Audit Committee and that: (1) relates 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 a critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Qualitative goodwill impairment assessment for the Columbia and ANR reporting units

As discussed in Notes 2 and 14 to the consolidated financial statements, the goodwill balance as of December 31, 2024 for the Columbia Pipeline Group, Inc. (Columbia) and the American Natural Resources (ANR) reporting units was $10,588 million and $2,803 million, respectively. The Company assesses goodwill for impairment testing annually or more frequently if events or changes in circumstances indicate that the carrying value of a reporting unit, including goodwill, might be impaired. The Company performed qualitative assessments to determine whether events or changes in circumstances indicate that the Columbia and ANR reporting units' goodwill might be impaired. These qualitative assessments were performed as of December 31, 2024.

We identified the evaluation of qualitative goodwill impairment indicators, or qualitative factors, for the Columbia and ANR reporting units as a critical audit matter. The assessment of the potential impact that these qualitative factors have on a reporting unit's fair value required the application of subjective auditor judgment. Qualitative factors include macroeconomic conditions, industry and market considerations, valuation multiples and discount rates, cost factors, historical and forecasted financial results and events specific to the reporting units, which required a higher degree of auditor judgment to evaluate. These qualitative factors could have had a significant effect on the Company's qualitative assessment and the potential for the need to perform a quantitative goodwill impairment test. 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 the Company's goodwill impairment assessment process, including controls related to the assessment of potential qualitative factors. We evaluated the Company's assessment of identified event-specific changes against our knowledge of event-specific changes obtained through other audit procedures. We evaluated information from analyst reports in the energy and utility industries, including global energy consumption forecasts and natural gas production forecasts, which were compared to geopolitical and market considerations used by the Company. We compared the current valuation multiples and discount rates, cost factors, historical and forecasted financial results of the reporting units, including the impact of newly approved growth projects, to assumptions used in the quantitative goodwill impairment tests performed in a previous period. In addition, we involved a valuation professional with specialized skills and knowledge, who assisted in:

- evaluating the Company's determination of the valuation multiples by comparing them to independently observed, recent market transactions of comparable assets and using publicly available market data for comparable entities
- evaluating the discount rates used by management in the assessment, by comparing them against a discount rate range that was independently developed using publicly available market data for comparable entities.

/s/ KPMG LLP

Chartered Professional Accountants
We have served as the Company's auditor since 1956.

Calgary, Canada
February 13, 2025

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, 2024, 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, 2024, 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, 2024 and 2023, the related consolidated statements of income, comprehensive income, cash flows, and equity for each of the years in the three-year period ended December 31, 2024, and the related notes (collectively, the consolidated financial statements), and our report dated February 13, 2025 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 Annual Report on Internal Control over Financial Reporting included in the Company's Management's Discussion and Analysis. 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 13, 2025

Consolidated statement of income

year ended December 31 (millions of Canadian $, except per share amounts)	2024	2023	2022
Revenues (Note 6)			
Canadian Natural Gas Pipelines	**5,600**	5,173	4,764
U.S. Natural Gas Pipelines	**6,339**	6,229	5,933
Mexico Natural Gas Pipelines	**870**	846	688
Power and Energy Solutions	**954**	1,019	924
Corporate	**8**	—	—
	13,771	13,267	12,309
Income (Loss) from Equity Investments (Note 11)	**1,558**	1,310	999
Impairment of Equity Investment (Note 7)	**—**	(2,100)	(3,048)
Operating and Other Expenses			
Plant operating costs and other	**4,413**	4,073	4,228
Commodity purchases resold	**217**	80	22
Property taxes	**820**	781	727
Depreciation and amortization	**2,535**	2,446	2,262
Goodwill impairment charge (Note 14)	**—**	—	571
	7,985	7,380	7,810
Net Gain (Loss) on Sale of Assets (Note 30)	**620**	—	—
Financial Charges			
Interest expense (Note 20)	**3,019**	2,966	2,300
Allowance for funds used during construction	**(784)**	(575)	(369)
Foreign exchange (gains) losses, net (Note 22)	**147**	(320)	185
Interest income and other	**(324)**	(272)	(140)
	2,058	1,799	1,976
Income (Loss) from Continuing Operations before Income Taxes	**5,906**	3,298	474
Income Tax Expense (Recovery) from Continuing Operations (Note 19)			
Current	**495**	864	363
Deferred	**427**	(22)	(41)
	922	842	322
Net Income (Loss) from Continuing Operations	**4,984**	2,456	152
Net Income (Loss) from Discontinued Operations, Net of Tax (Note 4)	**395**	612	633
Net Income (Loss)	**5,379**	3,068	785
Net income (loss) attributable to non-controlling interests (Note 23)	**681**	146	37
Net Income (Loss) Attributable to Controlling Interests	**4,698**	2,922	748
Preferred share dividends	**104**	93	107
Net Income (Loss) Attributable to Common Shares	**4,594**	2,829	641
Amounts Attributable to Common Shares			
Net income (loss) from continuing operations	**4,984**	2,456	152
Net income (loss) attributable to non-controlling interests (Note 23)	**681**	146	37
Net income (loss) attributable to controlling interests from continuing operations	**4,303**	2,310	115
Preferred share dividends	**104**	93	107
Net income (loss) attributable to common shares from continuing operations	**4,199**	2,217	8
Net income (loss) from discontinued operations, net of tax	**395**	612	633
Net Income (Loss) Attributable to Common Shares	**4,594**	2,829	641
Net Income (Loss) per Common Share - Basic and Diluted (Note 24)			
Continuing operations	**$4.05**	$2.15	$0.01
Discontinued operations	**$0.38**	$0.60	$0.63
	$4.43	$2.75	$0.64
Dividends Declared per Common Share	**$3.7025**	$3.72	$3.60
Weighted Average Number of Common Shares (millions) (Note 24)			
Basic	**1,038**	1,030	995
Diluted	**1,038**	1,030	996

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 $)	2024	2023	2022
Net Income (Loss)	**5,379**	3,068	785
Other Comprehensive Income (Loss), Net of Income Taxes			
Foreign currency translation gains and losses on net investment in foreign operations	**1,602**	(1,141)	1,494
Reclassification of foreign currency translation (gains) on net investment on disposal of foreign operations	**(25)**	—	—
Change in fair value of net investment hedges	**(18)**	17	(36)
Change in fair value of cash flow hedges	**35**	—	(39)
Reclassification to net income of (gains) losses on cash flow hedges	**(16)**	74	42
Unrealized actuarial gains (losses) on pension and other post-retirement benefit plans	**83**	(11)	63
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	**173**	(211)	867
Other comprehensive income (loss) (Note 26)	**1,828**	(1,272)	2,397
Comprehensive Income (Loss)	**7,207**	1,796	3,182
Comprehensive income (loss) attributable to non-controlling interests	**1,584**	(220)	45
Comprehensive Income (Loss) Attributable to Controlling Interests	**5,623**	2,016	3,137
Preferred share dividends	**104**	93	107
Comprehensive Income (Loss) Attributable to Common Shares	**5,519**	1,923	3,030

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 $)	2024	2023	2022
Cash Generated from Operations			
Net income (loss)	**5,379**	3,068	785
Depreciation and amortization	**2,788**	2,778	2,584
Goodwill and asset impairment charges and other (Notes 4 and 14)	**21**	(4)	453
Deferred income taxes (Note 19)	**493**	11	174
(Income) loss from equity investments (Note 11)	**(1,608)**	(1,377)	(1,054)
Impairment of equity investment (Note 7)	**—**	2,100	3,048
Distributions received from operating activities of equity investments (Note 11)	**1,675**	1,254	1,025
Employee post-retirement benefits funding, net of expense (Note 27)	**11**	(17)	(29)
Net (gain) loss on sale of assets (Note 30)	**(620)**	—	—
Equity allowance for funds used during construction	**(512)**	(367)	(248)
Unrealized (gains) losses on financial instruments (Note 28)	**340**	(342)	135
Expected credit loss provision (Note 28)	**(22)**	(83)	163
Foreign exchange (gains) losses on loans receivable	**(216)**	44	28
Other	**(232)**	(4)	(50)
(Increase) decrease in operating working capital (Note 29)	**199**	207	(639)
Net cash provided by operations	**7,696**	7,268	6,375
Investing Activities			
Capital expenditures (Note 5)	**(6,308)**	(8,007)	(6,678)
Capital projects in development (Note 5)	**(50)**	(142)	(49)
Contributions to equity investments (Notes 5, 7 and 11)	**(4,683)**	(4,149)	(3,433)
Acquisitions, net of cash acquired (Note 30)	**—**	(307)	—
Loans to affiliate (issued) repaid, net (Notes 7 and 12)	**—**	250	(11)
Keystone XL contractual recoveries	**7**	10	571
Proceeds from sales of assets, net of transaction costs (Note 30)	**791**	33	—
Other distributions from equity investments (Note 11)	**3,686**	23	2,632
Deferred amounts and other	**(352)**	2	(41)
Net cash (used in) provided by investing activities	**(6,909)**	(12,287)	(7,009)
Financing Activities			
Notes payable issued (repaid), net	**341**	(6,299)	766
Long-term debt issued, net of issue costs	**8,089**	15,884	2,508
Long-term debt repaid	**(9,273)**	(3,772)	(1,338)
Disposition of equity interest, net of transaction costs (Note 30)	**419**	5,328	—
Junior subordinated notes issued, net of issue costs	**1,465**	—	1,008
Cash transferred to South Bow, net of debt settlements	**(244)**	—	—
Dividends on common shares	**(3,953)**	(2,787)	(3,192)
Dividends on preferred shares	**(99)**	(92)	(106)
Contributions from non-controlling interests	**21**	—	—
Distributions to non-controlling interests and other	**(755)**	(173)	(87)
Common shares issued, net of issue costs	**88**	4	1,905
Preferred shares redeemed (Note 25)	**—**	—	(1,000)
Gains (losses) on settlement of financial instruments	**27**	—	23
Net cash (used in) provided by financing activities	**(3,874)**	8,093	487
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**210**	(16)	94
Increase (Decrease) in Cash and Cash Equivalents	**(2,877)**	3,058	(53)
Cash and Cash Equivalents			
Beginning of year	**3,678**	620	673
Cash and Cash Equivalents			
End of year	**801**	3,678	620

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 $)	2024	2023
ASSETS		
Current Assets		
Cash and cash equivalents	**801**	3,678
Accounts receivable	**2,611**	2,427
Inventories	**747**	771
Other current assets (Note 8)	**1,339**	1,419
Current assets of discontinued operations (Note 4)	**235**	3,077
	5,733	11,372
Plant, Property and Equipment (Note 9)	**77,501**	69,451
Net Investment in Leases (Note 10)	**2,477**	2,263
Equity Investments (Note 11)	**10,636**	9,240
Restricted Investments	**2,998**	2,532
Regulatory Assets (Note 13)	**2,682**	2,330
Goodwill (Note 14)	**13,670**	12,532
Other Long-Term Assets (Note 15)	**2,410**	2,881
Long-Term Assets of Discontinued Operations (Note 4)	**136**	12,433
	118,243	125,034
LIABILITIES		
Current Liabilities		
Notes payable (Note 16)	**387**	—
Accounts payable and other (Note 17)	**5,297**	4,305
Dividends payable	**874**	979
Accrued interest	**828**	913
Current portion of long-term debt (Note 20)	**2,955**	2,938
Current liabilities of discontinued operations (Note 4)	**170**	2,682
	10,511	11,817
Regulatory Liabilities (Note 13)	**5,303**	4,703
Other Long-Term Liabilities (Note 18)	**1,051**	991
Deferred Income Tax Liabilities (Note 19)	**6,884**	6,972
Long-Term Debt (Note 20)	**44,976**	49,976
Junior Subordinated Notes (Note 21)	**11,048**	10,287
Long-Term Liabilities of Discontinued Operations (Note 4)	**110**	1,280
	79,883	86,026
EQUITY		
Common shares, no par value (Note 24)	**30,101**	30,002
Issued and outstanding: December 31, 2024 – 1,039 million shares December 31, 2023 – 1,037 million shares		
Preferred shares (Note 25)	**2,499**	2,499
Retained earnings (Accumulated deficit)	**(5,241)**	(2,997)
Accumulated other comprehensive income (loss) (Note 26)	**233**	49
Controlling Interests	**27,592**	29,553
Non-Controlling Interests (Note 23)	**10,768**	9,455
	38,360	39,008
	118,243	125,034

Commitments, Contingencies and Guarantees (Note 31)

Variable Interest Entities (Note 32)

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 $)	2024	2023	2022
Common Shares (Note 24)			
Balance at beginning of year	**30,002**	28,995	26,716
Shares issued:			
Exercise of stock options	**99**	4	183
Dividend reinvestment and share purchase plan	**—**	1,003	342
Under public offering, net of issue costs	**—**	—	1,754
Balance at end of year	**30,101**	30,002	28,995
Preferred Shares (Note 25)			
Balance at beginning of year	**2,499**	2,499	3,487
Redemption of shares	**—**	—	(988)
Balance at end of year	**2,499**	2,499	2,499
Additional Paid-In Capital			
Balance at beginning of year	**—**	722	729
Issuance of stock options, net of exercises	**(5)**	9	(7)
Disposition of equity interest, net of transaction costs (Note 30)	**(41)**	(3,537)	—
Reclassification of additional paid-in capital deficit to accumulated deficit	**46**	2,806	—
Balance at end of year	**—**	—	722
Retained Earnings (Accumulated Deficit)			
Balance at beginning of year	**(2,997)**	819	3,773
Net income (loss) attributable to controlling interests	**4,698**	2,922	748
Common share dividends	**(3,842)**	(3,839)	(3,595)
Preferred share dividends	**(104)**	(93)	(95)
Spinoff of Liquids Pipelines business (Note 4)	**(2,950)**	—	—
Reclassification of additional paid-in capital deficit to accumulated deficit	**(46)**	(2,806)	—
Redemption of preferred shares	**—**	—	(12)
Balance at end of year	**(5,241)**	(2,997)	819
Accumulated Other Comprehensive Income (Loss) (Note 26)			
Balance at beginning of year	**49**	955	(1,434)
Other comprehensive income (loss) attributable to controlling interests	**946**	(379)	2,389
Impact of non-controlling interest (Note 30)	**(21)**	(527)	—
Spinoff of Liquids Pipelines business (Note 4)	**(741)**	—	—
Balance at end of year	**233**	49	955
Equity Attributable to Controlling Interests	**27,592**	29,553	33,990
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**9,455**	126	125
Disposition of equity and non-controlling interests (Note 30)	**461**	9,451	—
Non-controlling interests on acquisition of Texas Wind Farms (Note 30)	**—**	222	—
Net income (loss) attributable to non-controlling interests (Note 23)	**681**	146	37
Other comprehensive income (loss) attributable to non-controlling interests	**903**	(366)	8
Contributions from non-controlling interests	**21**	—	—
Distributions declared to non-controlling interests	**(753)**	(124)	(44)
Balance at end of year	**10,768**	9,455	126
Total Equity	**38,360**	39,008	34,116

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 41,121 km (25,552 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 49,681 km (30,870 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 2,885 km (1,791 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 July 27, 2023, TC Energy announced plans to separate into two independent, investment-grade, publicly listed companies through the spinoff of its Liquids Pipelines business. TC Energy shareholders voted to approve the plan in June 2024 and, 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). TC Energy shareholders as of September 25, 2024 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. TC Energy common shares resumed regular way trading on the TSX and NYSE on October 2, 2024. South Bow's common shares commenced regular way trading on the TSX on October 2, 2024 and on the NYSE on October 8, 2024, under the ticker symbol SOBO. 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. To the extent there are interests owned by other parties, these interests are included in 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.

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 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, the assessment of goodwill impairment indicators and fair value of reporting units that contain goodwill (Note 14).

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:

- provisions for indemnities related to the South Bow Separation Agreement (Note 4)
- recoverability and depreciation rates of plant, property and equipment (Note 9)
- allocation of consideration to lease and non-lease components in a contract that contains a lease (Note 10)
- assumptions used to measure the carrying amount of and expected credit losses on net investment in leases and certain contract assets (Notes 10 and 28)
- fair value of equity investments (Note 11)
- carrying value of regulatory assets and liabilities (Note 13)
- recognition of asset retirement obligations (Note 18)
- 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 19)
- assumptions used to measure retirement and other post-retirement benefit obligations (Note 27)
- fair value of financial instruments (Note 28)
- fair value of Fluvanna Wind Farm and Blue Cloud Wind Farm (Texas Wind Farms) assets (Note 30)
- commitments and provisions for contingencies and guarantees (Note 31).

TC Energy continues to assess climate-related impacts on the consolidated financial statements. There are ongoing developments in the ESG 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 B.C. Oil and Gas Commission. 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 Energy Regulatory Commission (CRE). 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 this variable revenue to be "constrained" as it cannot be reliably estimated and, therefore, recognizes variable revenue when the service is provided.

Revenues from contracts with customers are recognized net of any commodity taxes collected from customers which are subsequently remitted to governmental authorities. 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 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.

Other
Through the year, the Company was contracted to provide pipeline construction services to a partially-owned entity for a development fee. The development fee was considered variable consideration due to refund provisions in the contract. The Company recognized its estimate of the most likely amount of the variable consideration to which it was entitled. The development fee was recognized over time as the services were provided based on the input method using an estimate of activity level.

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 CRE-approved 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. The Company does not take ownership of the natural gas that it stores for customers.

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 0.75 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 credit recognized 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 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 the 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 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. 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 lease receivable and sales-type lease income.

At lease commencement, the Company recognizes a net investment in lease represented by the present value of both the future lease payments and the estimated residual value of the leased asset. 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 analysis 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 both the goodwill disposed and the portion of 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 classified as available for sale and 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

TC Energy's Stock Option Plan permits options for the purchase of common shares to be awarded to certain employees, including officers. Stock options granted are 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 Accumulated other comprehensive income (loss) (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. 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 to net income in the event the Company reduces its net investment in a foreign operation.

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 2024

Segment Reporting

In November 2023, the Financial Accounting Standards Board (FASB) issued new guidance to improve disclosures about a public entity's reportable segments and address requests from investors for additional, more detailed information about a reportable segment's expenses. The guidance was effective for annual periods beginning January 1, 2024 and interim periods beginning January 1, 2025. The Company adopted the guidance effective January 1, 2024. Refer to Note 5, Segmented information.

Leases

In March 2023, the FASB issued new guidance that clarified the accounting for leasehold improvements associated with common control leases. This new guidance was effective January 1, 2024 and adoption did not have a material impact on the Company's consolidated financial statements.

Future Accounting Changes

Income Taxes

In December 2023, the FASB issued new guidance to enhance the transparency and decision usefulness of income tax disclosures through improvements to the rate reconciliation and income taxes paid information. The guidance also includes certain other amendments to improve the effectiveness of income tax disclosures. This new guidance is effective for annual periods beginning January 1, 2025. The guidance is applied prospectively with retrospective application permitted. Early adoption is permitted for annual financial statements not yet issued. The Company intends to adopt the guidance prospectively and does not intend to early adopt the guidance. The Company is currently assessing the impact of the standard on the Company's consolidated financial statements, but does not expect the guidance to have a material impact on the Company's financial position or results of operations.

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 intends to adopt the guidance prospectively and does not intend to early adopt the guidance. 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

Agreements

Pursuant to the October 1, 2024 Spinoff Transaction described in Note 1, Description of TC Energy's business, TC Energy and South Bow have executed a series of agreements to outline the parameters and guidelines that govern their ongoing relationship. A Transition Services Agreement has been established to specify certain services that TC Energy will provide to South Bow for a period of up to two years. These services primarily include access to, and support of, systems that South Bow will continue to use until it has fully implemented new systems to support its business processes and warehouse management services.

A Tax Matters Agreement was executed to govern 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.

A Separation Agreement was established to specify the separation of assets and liabilities between TC Energy and South Bow. The agreement states, among other things, that TC Energy will indemnify South Bow for 86 per cent of total net liabilities and costs arising from the Milepost 14 incident that occurred on the Keystone Pipeline System in December 2022 and the existing variable toll disputes on the Keystone Pipeline System (excluding any future impacts with respect to the variable toll after October 1, 2024), subject to a maximum liability to South Bow of $30 million, in aggregate, for those two matters.

At December 31, 2023, the Company accrued a life-to-date environmental liability for the Milepost 14 incident of $794 million, before expected insurance recoveries and not including potential fines and penalties which were indeterminable. Prior to the Spinoff Transaction, for the nine months ended September 30, 2024, amounts paid for the environmental remediation liability were $92 million (twelve months ended December 31, 2023 – $676 million). For the year ended December 31, 2024, the Company received $99 million (2023 – $575 million) from its insurance policies related to the costs for environmental remediation. In addition, the Company also received insurance proceeds of $36 million that were collected from the Company’s wholly-owned captive insurance subsidiary. As part of the Separation Agreement, all future insurance recoveries will remain with TC Energy.

For the year ended December 31, 2024, the Company recorded a pre-tax expense of $37 million for its current estimate of potential incremental costs related to the Milepost 14 incident. This amount represents TC Energy’s 86 per cent share pursuant to the indemnity provisions in the Separation Agreement.

Amounts accrued for these matters are recorded as current assets and liabilities from discontinued operations. Due to the inherent uncertainties of the final amounts to be settled under these indemnities, any amounts that may ultimately be payable in respect of these net liabilities to South Bow could differ materially from those reported at December 31, 2024.

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.

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 will be prepared in early 2025 outlining the proposed transfer of assets from TC Energy to South Bow. The Canadian DB Plan's assets to be transferred to South Bow are subject to regulatory approval and will be transferred when approval is received. As at December 31, 2024, these assets remain in the TC Energy DB Plan trust and have been reflected as Long-term assets of discontinued operations and a corresponding obligation to South Bow has been reflected as Long-term liabilities of discontinued operations on the Consolidated balance sheet. The assets related to the U.S. DB Plan were fully transferred to South Bow as at December 31, 2024.

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

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. As such, the results of discontinued operations excludes shared costs related to TC Energy’s corporate services and governance functions that had provided support, and whose costs had been historically allocated, to the Liquids Pipelines segment. Depreciation expense related to Corporate shared assets has also been excluded from the results of discontinued operations. The Company has elected to allocate a portion of interest expense incurred at the corporate level to discontinued operations.

Prior year amounts have been reclassified to present the Liquids Pipelines business as discontinued operations.

Income from Discontinued Operations

year ended December 31 (millions of Canadian $)	**2024**[1]	**2023**	**2022**
Revenues	**2,217**	2,667	2,668
Income (Loss) from Equity Investments	**50**	67	55
Operating and Other Expenses			
Plant operating costs and other	**806**	814	704
Commodity purchases resold	**387**	437	512
Property taxes	**84**	116	121
Depreciation and amortization	**253**	332	322
Asset impairment charge and other	**21**	(4)	(118)
	1,551	1,695	1,541
Segmented Earnings (Losses) from Discontinued Operations	**716**	1,039	1,182
Financial Charges			
Interest expense	**218**	297	288
Interest income and other	**(21)**	30	(6)
	197	327	282
Income (Loss) from Discontinued Operations before Income Taxes	**519**	712	900
Income tax expense (recovery)	**124**	100	267
Net Income (Loss) from Discontinued Operations, Net of Tax	**395**	612	633

1 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022.

Assets and Liabilities of Discontinued Operations

at December 31 (millions of Canadian $)	**2024**	**2023**
ASSETS		
Current Assets		
Accounts receivable	—	1,782
Inventories	—	211
Other current assets	**235**	1,084
	235	3,077
Plant, Property and Equipment	—	11,118
Equity Investments	—	1,074
Other Long-Term Assets	**136**	241
	371	15,510
LIABILITIES		
Current Liabilities		
Accounts payable and other	**170**	2,682
	170	2,682
Other Long-Term Liabilities	**110**	127
Deferred Income Tax Liabilities	—	1,153
	280	3,962

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 Accumulated other comprehensive income (loss) on the Consolidated statement of equity.

Cash Flows from Discontinued Operations

year ended December 31 (millions of Canadian $)	**2024**	**2023**	**2022**
Net cash provided by operations	670	1,026	709
Net cash (used in) provided by investing activities	(89)	87	502

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, 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 7, Coastal GasLink, 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.

year ended December 31, 2022 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Power and Energy Solutions	Corporate [1]	Total
Revenues	4,764	5,933	688	924	—	12,309
Intersegment revenues[2]	—	132	—	12	(144)	—
	4,764	6,065	688	936	(144)	12,309
Income (loss) from equity investments	18	292	122	539	28 [3]	999
Impairment of equity investment	(3,048)	—	—	—	—	(3,048)
Operating costs[2]	(1,976)	(2,282)	(221)	(570)	72 [4]	(4,977)
Depreciation and amortization	(1,198)	(887)	(98)	(72)	(7) [4]	(2,262)
Other segment items[5]	—	(571)	—	—	—	(571)
Segmented Earnings (Losses)	(1,440)	2,617	491	833	(51)	2,450
Interest expense						(2,300)
Allowance for funds used during construction						369
Foreign exchange gains (losses), net[3]						(185)
Interest income and other						140
Income (Loss) from Continuing Operations before Income Taxes						474
Income tax (expense) recovery from continuing operations						(322)
Net Income (Loss) from Continuing Operations						152
Net Income (Loss) from Discontinued Operations, Net of Tax						633
Net Income (Loss)						785
Net (income) loss attributable to non-controlling interests						(37)
Net Income (Loss) Attributable to Controlling Interests						748
Preferred share dividends						(107)
Net Income (Loss) Attributable to Common Shares						641
Capital Spending[6]						
Capital expenditures	3,274	2,137	1,027	93	41	6,572
Capital projects in development	—	—	—	49	—	49
Contributions to equity investments[7]	1,445	—	—	752	—	2,197
	4,719	2,137	1,027	894	41	8,818
Discontinued operations						143
						8,961

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 Income (loss) from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange gains and losses on the peso-denominated loans from affiliates which are fully offset in Foreign exchange gains (losses), net by the corresponding foreign exchange losses and gains on the affiliate receivable balance until March 15, 2022, when it was fully repaid upon maturity. Refer to Note 12, Loans receivable from affiliates, for additional information.

4 Includes shared costs and depreciation previously allocated to the Liquids Pipelines segment. Refer to Note 4, Discontinued operations, for additional information.

5 Other segment items includes a goodwill impairment charge. Refer to Note 14, Goodwill, for additional information.

6 Included in Investing activities in the Consolidated statement of cash flows.

7 Contributions to equity investments in the Corporate segment of $1.2 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 12, Loans receivable from affiliates, for additional information.

at December 31 (millions of Canadian $)	2024	2023
Total Assets by Segment		
Canadian Natural Gas Pipelines	**31,167**	29,782
U.S. Natural Gas Pipelines	**56,304**	50,499
Mexico Natural Gas Pipelines	**15,995**	12,003
Power and Energy Solutions	**10,217**	9,525
Corporate	**4,189**	7,715
	117,872	109,524
Discontinued Operations	**371**	15,510
	118,243	125,034

Geographic Information

year ended December 31 (millions of Canadian $)	2024	2023	2022
Revenues			
Canada – domestic	**5,579**	5,337	4,920
Canada – export	**953**	821	765
United States	**6,369**	6,263	5,936
Mexico	**870**	846	688
	13,771	13,267	12,309

at December 31 (millions of Canadian $)	2024	2023
Plant, Property and Equipment		
Canada	**26,354**	26,434
United States	**40,580**	35,640
Mexico	**10,567**	7,377
	77,501	69,451

6. REVENUES

Disaggregation of Revenues

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**
Other revenues[3]	**—**	**88**	**—**	**305**	**393**
Sales-type lease income[4]	**—**	**—**	**308**	**—**	**308**
Corporate revenues[5]	**—**	**—**	**—**	**—**	**8**
	5,600	**6,339**	**870**	**954**	**13,771**

1 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 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 Transportadora de Gas Natural de La Huasteca (TGNH) pipelines. Refer to Note 10, Leases, for additional information.
3 Other revenues include income from the Company's operating lease arrangements, marketing activities and financial instruments. Refer to Note 10, Leases, and Note 28, Risk management and financial instruments, for additional information.
4 Represents the sales-type lease income on the in-service TGNH pipelines. Refer to Note 10, Leases, 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
Other revenues[3]	—	248	—	229	477
Sales-type lease income[4]	—	—	279	—	279
	5,173	6,229	846	1,019	13,267

1 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 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 10, Leases, for additional information.
3 Other revenues include income from the Company's operating lease arrangements, marketing activities and financial instruments. Refer to Note 10, Leases, and Note 28, Risk management and financial instruments, for additional information.
4 Represents the sales-type lease income on the in-service TGNH pipelines. Refer to Note 10, Leases, for additional information.

year ended December 31, 2022 (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	4,696	4,621	507	—	9,824
Power generation	—	—	—	490	490
Natural gas storage and other[1,2]	68	1,298	54	391	1,811
	4,764	5,919	561	881	12,125
Other revenues[3,4]	—	14	—	43	57
Sales-type lease income[5]	—	—	127	—	127
	4,764	5,933	688	924	12,309

1 Includes $68 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 Includes $37 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 10, Leases, for additional information.

3 Other revenues include income from the Company's operating lease arrangements, marketing activities and financial instruments. Refer to Note 10, Leases, and Note 28, Risk management and financial instruments, for additional information.

4 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from H.R. 1, the Tax Cuts and Jobs Act (U.S. Tax Reform). Refer to Note 13, Rate-regulated businesses.

5 Represents the sales-type lease income on the in-service TGNH pipelines. Refer to Note 10, Leases, for additional information.

Contract Balances

at December 31 (millions of Canadian $)	2024	2023	Affected line item on the Consolidated balance sheet
Receivables from contracts with customers	**1,452**	1,388	Accounts receivable
Contract assets (Note 8)	**165**	151	Other current assets
Long-term contract assets (Note 15)	**608**	457	Other long-term assets
Contract liabilities[1] (Note 17)	**30**	47	Accounts payable and other
Long-term contract liabilities[1]	**—**	2	Other long-term liabilities

1 During the year ended December 31, 2024, $41 million (2023 – $47 million) of revenues were recognized that 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 and long-term contract liabilities primarily represent unearned revenue for contracted services. Under the terms of the consolidated Transportation Service Agreement (TSA), the contract liability relating to current and future in-service pipelines of the Company's Mexico-based subsidiary, Transportadora de Gas Natural de la Huasteca (TGNH), is netted against certain contract asset balances. The resulting net contract liability is settled against Net investment in leases on the Consolidated balance sheet when the pipeline enters into service.

Future Revenues from Remaining Performance Obligations

As at December 31, 2024, future revenues from long-term pipeline capacity arrangements and transportation as well as natural gas storage and other contracts extending through 2055 are approximately $29.1 billion, of which approximately $6.4 billion is expected to be recognized in 2025.

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.

7. COASTAL GASLINK

On November 18, 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 pipeline, allowing for the collection of tolls from customers retroactive to October 1, 2024. The agreement also includes a one-time payment of $199 million from LNGC Participants to TC Energy in recognition of the completion of certain work and the final settlement of costs. The payment is to be made by LNGC Participants upon the earlier of three months after the declared in-service of the LNGC facility, or December 15, 2025. The payment, which accrues in full to TC Energy in accordance with the contractual terms between the Coastal GasLink LP partners, has been accounted for as an in-substance equity distribution from Coastal GasLink LP and reflected in Accounts receivable and Equity investments on the Company's Consolidated balance sheet at December 31, 2024.

Subordinated Loan Agreement

TC Energy has a subordinated loan agreement with Coastal GasLink LP under which the Company advances non-revolving interest-bearing loans subject to floating market-based rates to Coastal GasLink LP to fund capital costs to complete the Coastal GasLink pipeline. At December 31, 2023, this loan had a committed capacity of $3,375 million.

Coastal GasLink LP partners, including TC Energy, were contractually obligated to contribute equity to Coastal GasLink LP to ultimately fund the settlement of amounts outstanding under the subordinated loan agreement. Because of the expectation that the Company would predominantly fund the settlement of the amounts outstanding, amounts drawn under the subordinated loan agreement have been accounted for as in-substance equity contributions and are 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 are accounted for as in-substance equity distributions and are presented in Other distributions from equity investments in the Company's Consolidated statement of cash flows.

During the year ended December 31, 2024, draws of $627 million (2023 - $2,520 million) were made by Coastal GasLink LP under 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 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. This repayment reduced the Company's funding commitment under the subordinated loan agreement to $228 million at December 31, 2024. At December 31, 2024, $228 million (December 31, 2023 - $855 million) in unused committed capacity remains available for use by Coastal GasLink LP. At December 31, 2024, the balance of loans outstanding under the subordinated loan agreement was nil (December 31, 2023 - $2,520 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 (December 31, 2023 - $100 million) with no outstanding balances at December 31, 2024 and 2023.

Impairment of Equity Investment in Coastal GasLink LP

In February 2023, Coastal GasLink LP announced an increase in the revised capital cost of the Coastal GasLink pipeline. As noted above, the expectation was that equity contributions to fund the increased capital cost would be predominantly funded by TC Energy. For the year ended December 31, 2022 until the quarter ended September 30, 2023, 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 in each of these periods and concluded that the fair value of its investment in Coastal GasLink LP was below its carrying value in each period assessed, reflecting other-than-temporary impairments. As a result, the Company recorded cumulative pre-tax 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, 2024, the carrying value of the Company's investment in Coastal GasLink LP was $1,006 million (2023 – $294 million).

8. OTHER CURRENT ASSETS

at December 31 (millions of Canadian $)	**2024**	**2023**
Fair value of derivative contracts (Note 28)	**347**	589
Current portion of net investment in leases (Note 10)	**333**	306
Contract assets (Note 6)	**165**	151
Cash provided as collateral	**128**	28
Regulatory assets (Note 13)	**123**	76
Prepaid expenses	**86**	87
Emissions credits	**75**	94
Other	**82**	88
	1,339	1,419

9. PLANT, PROPERTY AND EQUIPMENT

at December 31	2024			2023		
(millions of Canadian $)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Canadian Natural Gas Pipelines						
NGTL System						
Pipeline	**20,497**	**7,413**	**13,084**	20,232	6,855	13,377
Compression	**7,146**	**2,497**	**4,649**	6,603	2,349	4,254
Metering and other	**1,668**	**883**	**785**	1,589	830	759
	29,311	**10,793**	**18,518**	28,424	10,034	18,390
Under construction	**503**	**—**	**503**	787	—	787
	29,814	**10,793**	**19,021**	29,211	10,034	19,177
Canadian Mainline						
Pipeline	**10,907**	**8,165**	**2,742**	10,729	7,996	2,733
Compression	**4,540**	**3,448**	**1,092**	4,437	3,354	1,083
Metering and other	**749**	**331**	**418**	729	308	421
	16,196	**11,944**	**4,252**	15,895	11,658	4,237
Under construction	**163**	**—**	**163**	147	—	147
	16,359	**11,944**	**4,415**	16,042	11,658	4,384
Other Canadian Natural Gas Pipelines[1]						
Other	**2,927**	**1,742**	**1,185**	2,846	1,682	1,164
Under construction	**31**	**—**	**31**	23	—	23
	2,958	**1,742**	**1,216**	2,869	1,682	1,187
	49,131	**24,479**	**24,652**	48,122	23,374	24,748
U.S. Natural Gas Pipelines						
Columbia Gas						
Pipeline	**14,826**	**1,472**	**13,354**	12,952	1,247	11,705
Compression	**6,153**	**677**	**5,476**	5,310	559	4,751
Metering and other	**4,570**	**455**	**4,115**	4,074	372	3,702
	25,549	**2,604**	**22,945**	22,336	2,178	20,158
Under construction	**891**	**—**	**891**	771	—	771
	26,440	**2,604**	**23,836**	23,107	2,178	20,929
ANR						
Pipeline	**2,477**	**745**	**1,732**	2,117	657	1,460
Compression	**4,446**	**938**	**3,508**	3,928	773	3,155
Metering and other	**1,832**	**521**	**1,311**	1,625	458	1,167
	8,755	**2,204**	**6,551**	7,670	1,888	5,782
Under construction	**853**	**—**	**853**	404	—	404
	9,608	**2,204**	**7,404**	8,074	1,888	6,186

at December 31	2024			2023		
(millions of Canadian $)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Other U.S. Natural Gas Pipelines						
Columbia Gulf	**4,127**	**304**	**3,823**	3,600	256	3,344
GTN	**3,405**	**1,467**	**1,938**	2,992	1,295	1,697
Great Lakes	**2,602**	**1,537**	**1,065**	2,359	1,401	958
Other[2]	**1,695**	**628**	**1,067**	2,071	800	1,271
	11,829	**3,936**	**7,893**	11,022	3,752	7,270
Under construction	**694**	**—**	**694**	584	—	584
	12,523	**3,936**	**8,587**	11,606	3,752	7,854
	48,571	**8,744**	**39,827**	42,787	7,818	34,969
Mexico Natural Gas Pipelines[3]						
Pipeline	**2,590**	**523**	**2,067**	2,290	422	1,868
Compression	**476**	**107**	**369**	447	82	365
Metering and other	**398**	**99**	**299**	395	85	310
	3,464	**729**	**2,735**	3,132	589	2,543
Under construction	**7,807**	**—**	**7,807**	4,823	—	4,823
	11,271	**729**	**10,542**	7,955	589	7,366
Power and Energy Solutions						
Natural Gas Power Generation	**1,273**	**671**	**602**	1,239	637	602
Natural Gas Storage and Other	**873**	**281**	**592**	845	256	589
Renewable Power Generation	**779**	**54**	**725**	581	19	562
	2,925	**1,006**	**1,919**	2,665	912	1,753
Under construction	**56**	**—**	**56**	153	—	153
	2,981	**1,006**	**1,975**	2,818	912	1,906
Corporate	**944**	**439**	**505**	909	447	462
	112,898	**35,397**	**77,501**	102,591	33,140	69,451

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. On August 15, 2024, the Company completed the sale of Portland Natural Gas Transmission System (PNGTS). Refer to Note 30, Strategic alliance, acquisitions and dispositions, for additional information.

3 During the year ended December 31, 2024, the Company derecognized nil (2023 – $407 million) of Plant, property and equipment and recorded a corresponding asset for Net investment in leases for the in-service TGNH pipelines. Refer to Note 10, Leases, for additional information.

10. 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 $)	2024	2023
Operating lease cost[1]	**117**	105
Sublease income	**(6)**	(4)
Net operating lease cost	**111**	101

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 $)	2024	2023
Cash paid for amounts included in the measurement of operating lease liabilities	**74**	72
ROU assets obtained in exchange for new operating lease liabilities	**96**	83

at December 31	2024	2023
Weighted average remaining lease term	**13 years**	13 years
Weighted average discount rate	**3.3%**	3.3%

Maturities of operating lease liabilities are as follows:

at December 31 (millions of Canadian $)	2024	2023
Less than one year	**73**	71
One to two years	**73**	68
Two to three years	**66**	66
Three to four years	**64**	59
Four to five years	**63**	58
More than five years	**275**	224
Total operating lease payments	**614**	546
Imputed interest	**(103)**	(89)
Operating lease liabilities	**511**	457

The amounts recognized on TC Energy's Consolidated balance sheet for its operating lease liabilities were as follows:

at December 31 (millions of Canadian $)	2024	2023
Accounts payable and other (Note 17)	**60**	57
Other long-term liabilities (Note 18)	**451**	400
	511	457

As at December 31, 2024, the carrying value of the ROU assets recorded under operating leases was $480 million (2023 – $435 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, 2024 was $114 million (2023 – $112 million; 2022 – $110 million).

Future lease payments to be received under operating leases are as follows:

at December 31 (millions of Canadian $)	2024	2023
Less than one year	**107**	111
One to two years	**76**	94
Two to three years	**9**	70
Three to four years	**10**	—
Four to five years	**10**	—
More than five years	**55**	—
	267	275

At December 31, 2024, the cost and accumulated depreciation for facilities accounted for as operating leases was $697 million and $351 million, respectively (2023 – $646 million and $333 million, respectively).

Sales-Type Leases

The Tamazunchale, Villa de Reyes and Tula pipelines are part of a U.S. dollar-denominated take-or-pay TSA that extends through 2055 between TGNH and the Comisión Federal de Electricidad (CFE).

The consolidated TSA contains a lease with 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, 2024. 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.

During 2024, the Company did not enter into any new sales-type lease arrangements (2023 – $407 million).

Future lease payments to be received under the existing sales-type leases are as follows:

at December 31 (millions of Canadian $)	**2024**	**2023**
Less than one year	**333**	305
One to two years	**333**	305
Two to three years	**333**	305
Three to four years	**333**	305
Four to five years	**333**	305
More than five years	**8,499**	8,102
	10,164	9,627

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 $)	**2024**	**2023**
Net Investment in Leases		
Minimum lease payments	**10,164**	9,627
Unearned lease income	**(7,323)**	(7,006)
Lease receivable	**2,841**	2,621
Expected credit loss provision[1]	**(59)**	(76)
Present value of unguaranteed residual value	**28**	24
	2,810	2,569
Current portion included in Other current assets (Note 8)	**(333)**	(306)
	2,477	2,263

1 Includes $6 million (2023 – nil) of foreign currency translation losses.

Future lease payments will increase as assets associated with sales-type leases come into service.

For the year ended December 31, 2024, the Company recorded $308 million (2023 – $279 million; 2022 - $127 million) of sales-type lease income.

For the year ended December 31, 2024, the Company recorded a $23 million ECL recovery (2023 – a recovery of $73 million; 2022 – an expense of $149 million) relating to net investment in leases in Plant operating costs and other. Refer to Note 28, Risk management and financial instruments, for additional information.

11. EQUITY INVESTMENTS

(millions of Canadian $)	Ownership Interest at December 31, 2024	Income (Loss) from Equity Investments year ended December 31			Equity Investments at December 31	
		2024	**2023**	**2022**	**2024**	**2023**
Canadian Natural Gas Pipelines						
TQM[1]	50%	**17**	17	17	**160**	166
Coastal GasLink[1,2]	35%	**17**	203	1	**1,006**	294
U.S. Natural Gas Pipelines						
Northern Border	50%	**130**	101	92	**647**	599
Millennium	47.5%	**95**	109	103	**(21)**	476
Iroquois	50%	**100**	98	77	**221**	227
Other	Various	**16**	16	20	**135**	120
Mexico Natural Gas Pipelines						
Sur de Texas	60%	**283**	78	150	**1,403**	1,078
Power and Energy Solutions						
Bruce Power[1]	48.3%	**900**	690	537	**7,043**	6,242
Other	Various	**—**	(2)	2	**42**	38
		1,558	1,310	999	**10,636**	9,240

1 Classified as a VIE. Refer to Note 32, Variable interest entities, for additional information.
2 Refer to Note 7, Coastal GasLink, for additional information.

Coastal GasLink Incentive Payment

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.

Distributions and Contributions

Distributions received from equity investments and contributions made to equity investments for the years ended December 31, 2024, 2023 and 2022 were as follows:

year ended December 31 (millions of Canadian $)	**2024**	**2023**	**2022**
Distributions			
Distributions received from operating activities of equity investments	**1,607**	1,158	955
Coastal GasLink LP subordinated loan repayment[1,2]	**3,147**	—	—
Sur de Texas debt repayments[2,3]	**—**	—	2,404
Other[2]	**539**	23	228
	5,293	1,181	3,587
Contributions[2]			
Contributions to Coastal GasLink LP[1]	**3,964**	3,231	1,414
Sur de Texas debt financing[3]	**—**	—	1,199
Contributions made to other equity investments	**719**	918	783
	4,683	4,149	3,396

1 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 7, Coastal GasLink, for additional information.
2 Included in Investing activities in the Consolidated statement of cash flows.
3 Represents TC Energy's proportionate share of the Sur de Texas debt financing requirements and subsequent repayments. Refer to Note 12, Loans receivable from affiliates, for additional information.

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian $)	2024	2023	2022
Income			
Revenues	**6,962**	6,197	5,681
Operating and other expenses	**(3,783)**	(3,343)	(3,290)
Net income	**3,026**	2,457	2,031
Net income attributable to TC Energy	**1,558**	1,310	999

at December 31 (millions of Canadian $)	2024	2023
Balance Sheet		
Current assets	**3,959**	3,279
Non-current assets	**44,835**	41,270
Current liabilities	**(2,111)**	(2,403)
Non-current liabilities	**(21,729)**	(21,894)

At December 31, 2024, the cumulative carrying value of the Company's equity investments was $769 million (2023 – $278 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. Refer to Note 7, Coastal GasLink, for additional information.

12. LOANS RECEIVABLE FROM 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 has been contracted to develop, construct and operate the Coastal GasLink pipeline. The Company has a subordinated loan agreement and a subordinated demand revolving credit facility with Coastal GasLink LP. Refer to Note 7, Coastal GasLink, for additional information.

Sur de Texas

TC Energy holds a 60 per cent equity interest in a joint venture with IEnova to own the Sur de Texas pipeline, for which TC Energy is the operator. In 2017, TC Energy entered into a MXN$21.3 billion unsecured revolving credit facility with the joint venture, which bore interest at a floating rate and was fully repaid upon maturity on March 15, 2022 in the amount of $1.2 billion.

The Company's Consolidated statement of income reflects the related interest income and foreign exchange impact on this loan receivable until its repayment on March 15, 2022, which were fully offset upon consolidation with corresponding amounts included in TC Energy's proportionate share of Sur de Texas equity earnings as follows:

year ended December 31 (millions of Canadian $)	2024	2023	2022	Affected line item in the Consolidated statement of income
Interest income[1]	—	—	19	Interest income and other
Interest expense[2]	—	—	(19)	Income (loss) from equity investments
Foreign exchange losses[1]	—	—	(28)	Foreign exchange (gains) losses, net
Foreign exchange gains[1]	—	—	28	Income (loss) from equity investments

1 Included in the Corporate segment.
2 Included in the Mexico Natural Gas Pipelines segment.

On March 15, 2022, as part of refinancing activities with the Sur de Texas joint venture, the peso-denominated inter-affiliate loan discussed above was replaced with a new U.S. dollar-denominated inter-affiliate loan from TC Energy of an equivalent $1.2 billion (US$938 million) with a floating interest rate. On July 29, 2022, the Sur de Texas joint venture entered into an unsecured term loan agreement with third parties, the proceeds of which were used to fully repay the U.S. dollar-denominated inter-affiliate loan with TC Energy.

13. 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 regulators' established rates, provided the rates are designed to recover the costs of providing the regulated 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. 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

Prior to December 31, 2024, the NGTL System operated under the 2020-2024 Revenue Requirement Settlement (the 2020-2024 Settlement). The 2020-2024 Settlement 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 are shared with its customers.

In September 2024, the CER approved a new five-year negotiated revenue requirement settlement (the 2025–2029 NGTL Settlement) which commenced on January 1, 2025. The settlement enables an investment framework that supports the approval by the Company's Board of Directors (Board) to allocate approximately $3.3 billion of capital towards progression of a new multi-year growth plan for expansion facilities on the NGTL System. It is comprised of multiple distinct projects with targeted in-service dates between 2027 and 2030 that are 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 current settlement if tolls exceed a pre-determined level or if final Company approvals of the multi-year growth plan are not obtained.

Canadian Mainline
The Canadian Mainline currently operates under the terms of the 2015-2030 Tolls Application approved in 2014 (the 2014 Decision). 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. Similar to the STAA, the long-term adjustment account (LTAA) and bridging account were used to capture the surplus or shortfall between the Company's revenues and cost of service during the previous settlement and are amortized over the life of 2021-2026 Settlement and the 2014 Decision respectively.

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 February 2022 (the 2022 Columbia Gas Settlement). As part of the settlement, there is a moratorium on any further rate changes until April 1, 2025, and Columbia Gas must file for new rates with an effective date no later than April 1, 2026. Additionally, Columbia Gas maintains a FERC-approved modernization program allowing for the cost recovery and return on additional investment up to US$1.2 billion over a four-year period through 2024 to modernize the Columbia Gas system, thereby improving system integrity and enhancing service reliability and flexibility.

In September 2024, Columbia Gas filed a general NGA Section 4 rate case with FERC requesting an increase to Columbia Gas' maximum transportation rates effective April 1, 2025, subject to refund based on the outcome of the proceeding.

ANR Pipeline
ANR Pipeline operates under rates established through a 2022 FERC-approved rate settlement (the 2022 ANR Settlement). The 2022 ANR Settlement reflects the agreement of ANR Pipeline, its customers and FERC staff to resolve all outstanding issues pertaining to the original rate case filing in January 2022 and was effective August 2022. The 2022 ANR Settlement received FERC approval on April 11, 2023. As part of the settlement, there is a moratorium on any further rate changes until November 1, 2025. ANR must file for new rates with an effective date no later than August 1, 2028. The settlement also included an additional rate step up effective August 2024 related to certain modernization projects. In 2023, previously accrued rate refund liabilities, including interest, were refunded to 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 on April 26, 2022 (the 2022 Great Lakes Settlement), which maintains Great Lakes' existing maximum transportation rates through October 31, 2025. The 2022 Great Lakes Settlement contains a moratorium until October 31, 2025. Great Lakes will be required to file for new rates no later than April 30, 2025, with such new rates effective no later than November 1, 2025.

Tuscarora

Tuscarora operates under rates established as part of the FERC-approved rate settlement on September 6, 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

On September 29, 2023, Gas Transmission Northwest (GTN) filed a general NGA Section 4 Rate Case with FERC, requesting an increase to GTN's maximum rates to become effective April 1, 2024, and subject to refund. On August 9, 2024, GTN filed a settlement with FERC resolving all issues in the general NGA Section 4 Rate Case. On October 21, 2024, the settlement was approved by FERC.

Mexico Regulated Operations

TC Energy's Mexico natural gas pipelines are regulated by CRE and operate in accordance with CRE-approved tariffs. 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)	2024	2023
Regulatory Assets			
Deferred income taxes[1]	n/a	**2,593**	2,204
Operating and debt-service regulatory assets[2]	1	**56**	29
Pensions and other post-retirement benefits[1,3]	n/a	**—**	54
Foreign exchange on long-term debt[1,4]	1-5	**39**	11
Other	n/a	**117**	108
		2,805	2,406
Less: Current portion included in Other current assets (Note 8)		**123**	76
		2,682	2,330
Regulatory Liabilities			
Pipeline abandonment trust balances[5]	n/a	**2,686**	2,252
Deferred income taxes – U.S. Tax Reform[6]	n/a	**1,197**	1,137
Canadian Mainline short-term adjustment and toll-stabilization accounts[7,8]	n/a	**553**	437
Cost of removal[9]	n/a	**376**	351
Canadian Mainline bridging amortization account[7]	6	**322**	376
Deferred income taxes[1]	n/a	**188**	198
Pensions and other post-retirement benefits[3]	n/a	**122**	6
Canadian Mainline long-term adjustment account[7,10]	2	**74**	111
Operating and debt-service regulatory liabilities[2]	1	**50**	23
ANR post-employment and retirement benefits other than pension[11]	n/a	**45**	42
Other	n/a	**43**	54
		5,656	4,987
Less: Current portion included in Accounts payable and other (Note 17)		**353**	284
		5,303	4,703

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 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.
4 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.
5 This balance represents the amounts collected in tolls from customers and included in the LMCI restricted investments to fund future abandonment of the Company's CER-regulated pipeline facilities.
6 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.
7 These regulatory accounts are used to capture revenue and cost variances plus toll-stabilization adjustments during the 2015-2030 settlement term.
8 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.
9 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.
10 Under the terms of the 2021-2026 Mainline Settlement, $223 million is amortized over the six-year settlement term.
11 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 $45 million (US$32 million) balance at December 31, 2024 is subject to resolution through future regulatory proceedings and, accordingly, a settlement period cannot be determined at this time.

14. GOODWILL

The Company's Goodwill balance on the Consolidated balance sheet is comprised of the following amounts:

at December 31	2024		2023	
(millions)	Canadian dollars	U.S. dollars	Canadian dollars	U.S. dollars
Columbia Pipeline Group, Inc.	**10,588**	**7,351**	9,708	7,351
ANR	**2,803**	**1,946**	2,570	1,946
Great Lakes	**176**	**122**	161	122
North Baja	**70**	**48**	63	48
Tuscarora	**33**	**23**	30	23
	13,670	**9,490**	12,532	9,490

Changes in Goodwill were as follows:

(millions of Canadian $)	U.S. Natural Gas Pipelines
Balance at January 1, 2023	12,843
Foreign exchange rate changes	(311)
Balance at December 31, 2023[1]	12,532
Foreign exchange rate changes	**1,138**
Balance at December 31, 2024[1]	**13,670**

1 Represents gross amounts of goodwill as at December 31, 2024 of $15,405 million (2023 – $14,267 million), net of accumulated impairment of $1,735 million (2023 – $1,735 million).

As part of the annual goodwill impairment assessment at December 31, 2024, the Company evaluated qualitative factors impacting the fair value of the underlying reporting units. 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

On October 4, 2023, as part of the asset divestiture program announced in 2022, the Company successfully completed the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf. In conjunction with the process leading up to the sale, the Company performed a quantitative goodwill impairment test at June 30, 2023.

The estimated fair value measurements used in the Company's goodwill impairment analysis are classified as Level III of the fair value hierarchy. In the determination of the fair value utilized in the quantitative goodwill impairment test for the Columbia reporting unit, the Company performed a discounted cash flow model analysis using projections of future cash flows and applied a risk-adjusted discount rate and value multiple which involved significant estimates and judgments. It was determined that the fair value of the Columbia reporting unit, inclusive of the Columbia Gas and Columbia Gulf business units, exceeded its carrying value, including goodwill. Although goodwill was not impaired, the estimated fair value in excess of the carrying value was less than 10 per cent. There is a risk that reductions in future cash flow forecasts and adverse changes in other key assumptions could result in a future impairment of a portion of the goodwill balance relating to Columbia.

Great Lakes

In March 2022, an impairment loss of $571 million ($531 million after tax) was recognized for the excess carrying value over the estimated fair value of our Great Lakes reporting unit. There is a risk that reductions in future cash flow forecasts and adverse changes in other key assumptions could result in future impairment of the remaining goodwill balance.

15. OTHER LONG-TERM ASSETS

at December 31 (millions of Canadian $)	2024	2023
Employee post-retirement benefits (Note 27)	**758**	518
Long-term contract assets (Note 6)	**608**	457
Deferred income tax assets (Note 19)	**428**	1,319
Capital projects in development	**164**	234
Fair value of derivative contracts (Note 28)	**122**	155
Other	**330**	198
	2,410	2,881

16. NOTES PAYABLE

at December 31	2024		2023	
(millions of Canadian $, unless otherwise noted)	**Outstanding**	**Weighted Average Interest Rate per Annum**	**Outstanding**	**Weighted Average Interest Rate per Annum**
Canada[1]	**308**	**4.7%**	—	—
U.S. (2024 – US$55; 2023 – nil)	**79**	**4.7%**	—	—
	387		—	

1 At December 31, 2024, Notes payable consisted of Canadian dollar-denominated notes of nil (2023 – nil) and U.S. dollar-denominated notes of US$214 million (2023 – nil).

At December 31, 2024, Notes payable reflects short-term borrowings in Canada by TCPL and in the U.S. by TransCanada PipeLine USA Ltd. (TCPL USA).

At December 31, 2024, total committed revolving and demand credit facilities were $12.2 billion (2023 – $12.9 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)			2024		2023
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 2029	**3.0**	**3.0**	3.0
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2025	**US 1.0**	**US 0.7**	US 2.5
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2027	**US 2.5**	**US 2.5**	US 2.5
Columbia Pipelines Holding Company LLC[3]	Supports commercial paper program and general corporate purposes of the borrower	December 2027	**US 1.5**	**US 1.5**	US 1.0
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]	**1.1**	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, 2024, the Company was in compliance with all financial covenants.
3 Columbia Pipelines Holding Company LLC (CPHC 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, 2024, the cost to maintain the above facilities was $18 million (2023 – $16 million; 2022 – $14 million).

17. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	2024	2023
Trade payables	**3,699**	3,092
Fair value of derivative contracts (Note 28)	**507**	415
Regulatory liabilities (Note 13)	**353**	284
Income tax liabilities	**143**	76
Operating lease liabilities (Note 10)	**60**	57
Contract liabilities (Note 6)	**30**	47
Other	**505**	334
	5,297	4,305

18. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	2024	2023
Operating lease obligations (Note 10)	**451**	400
Fair value of derivative contracts (Note 28)	**209**	106
Asset retirement obligations	**108**	64
Employee post-retirement benefits (Note 27)	**94**	97
Other	**189**	324
	1,051	991

19. INCOME TAXES

Geographic Components of Income before Income Taxes

year ended December 31 (millions of Canadian $)	2024	2023	2022
Canada	**1,219**	(344)	(2,133)
Foreign	**4,687**	3,642	2,607
Income before Income Taxes	**5,906**	3,298	474

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	2024	2023	2022
Current			
Canada	**102**	61	41
Foreign	**393**	803	322
	495	864	363
Deferred			
Canada	**135**	8	(459)
Foreign	**292**	(30)	418
	427	(22)	(41)
Income Tax Expense	**922**	842	322

Reconciliation of Income Tax Expense

year ended December 31 (millions of Canadian $)	2024	2023	2022
Income before income taxes	**5,906**	3,298	474
Federal and provincial statutory tax rate	**23.0%**	23.0%	23.0%
Expected income tax expense	**1,358**	759	109
Mexico foreign exchange exposure	**(246)**	132	9
Income tax differential related to regulated operations	**(227)**	(260)	(174)
Income from non-controlling interests and equity investments	**(224)**	(56)	(54)
Foreign income tax rate differentials	**167**	(84)	(216)
Non-taxable capital (gains) and losses	**18**	182	173
Impact of Mexico inflationary adjustments	**7**	1	24
Valuation allowance (release)	**4**	182	198
Settlement of Mexico prior years' income tax assessments	**—**	—	196
Non-deductible goodwill impairment	**—**	—	91
Other	**65**	(14)	(34)
Income Tax Expense	**922**	842	322

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	2024	2023
Deferred Income Tax Assets		
Tax loss and credit carryforwards	**1,987**	1,664
Disallowed interest carryforward	**115**	—
Regulatory and other deferred amounts	**612**	583
Unrealized foreign exchange losses on long-term debt	**467**	206
Other	**143**	160
	3,324	2,613
Less: Valuation allowance	**931**	690
	2,393	1,923
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment	**6,488**	5,599
Equity investments	**1,280**	1,043
Taxes on future revenue requirement	**612**	496
Financial instruments	**168**	168
Other	**301**	270
	8,849	7,576
Net Deferred Income Tax Liabilities	**6,456**	5,653

The above deferred tax amounts have been classified on the Consolidated balance sheet as follows:

at December 31 (millions of Canadian $)	2024	2023
Deferred Income Tax Assets		
Other long-term assets (Note 15)	**428**	1,319
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**6,884**	6,972
Net Deferred Income Tax Liabilities	**6,456**	5,653

TC Energy recorded an income tax valuation allowance of $931 million and $690 million against the deferred income tax asset balances at December 31, 2024 and 2023, respectively. The increase in the valuation allowance is primarily a result of the foreign exchange movement on unrecognized capital losses. At December 31, 2023, the Company recorded a total of $358 million in valuation allowance as a result of the Coastal GasLink equity investment impairment that resulted in a portion of the impairment having unrealized non-taxable capital losses. These losses have not been recognized as of December 31, 2024. At each reporting date, the Company considers new evidence, both positive and negative, that could affect its view of the future realization of deferred tax assets. At December 31, 2024, the Company determined there was sufficient positive evidence to conclude that it is more likely than not that the net deferred tax assets will be realized.

At December 31, 2024, the Company has recognized the benefit of non-capital loss carryforwards of $6,740 million (2023 – $6,593 million) for federal and provincial purposes in Canada, which expire from 2030 to 2044. The Company has not yet recognized the benefit of capital loss carryforwards of $599 million (2023 – $478 million) for federal and provincial purposes in Canada which have no expiry date. The Company has Ontario corporate minimum tax (CMT) credits of $161 million (2023 – $140 million), which expire from 2026 to 2044. As of December 31, 2024, the Company has not recognized the benefit of CMT credits of $22 million (2023 – $22 million). As of December 31, 2024, the Company has recognized the benefit of disallowed Canadian interest expense of $480 million (2023 - nil) which may be carried forward indefinitely.

At December 31, 2024, the Company has recognized the benefit of net operating loss carryforwards of US$518 million (2023 – US$47 million) in Mexico, which expire from 2024 to 2034.

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, 2024 by approximately $1,728 million (2023 – $1,443 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $387 million, net of refunds, were made in 2024 (2023 – payments, net of refunds, of $791 million; 2022 – payments, net of refunds, of $394 million).

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 $)	2024	2023	2022
Unrecognized tax benefit at beginning of year	**85**	91	80
Gross increases – tax positions in prior years	**3**	9	6
Gross decreases – tax positions in prior years	**(2)**	(1)	—
Gross increases – tax positions in current year	**5**	16	7
Gross decrease – tax positions in current year	**(2)**	—	—
Settlement	**(13)**	—	—
Lapse of statutes of limitations	**(4)**	(30)	(2)
Unrecognized Tax Benefit at End of Year	**72**	85	91

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, 2024 reflects $1 million interest recovery (2023 – $3 million expense; 2022 – $6 million expense). At December 31, 2024, the Company accrued $19 million in interest expense (2023 – $20 million; 2022 – $18 million). The Company incurred no penalties associated with income tax uncertainties related to income tax expense for the years ended December 31, 2024, 2023 and 2022 and no penalties were accrued as at December 31, 2024, 2023 and 2022.

Subject to the results of audit examinations by taxing authorities and other legislative amendments, TC Energy does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its financial statements.

TC Energy and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2016. Substantially all material U.S. federal, state and local income tax matters have been concluded for years through 2016. Substantially all material Mexico income tax matters have been concluded for years through 2018.

Mexico Tax Audit

In 2019, the Mexican tax authority, the Tax Administration Services (SAT), completed an audit of the 2013 tax return of one of the Company's subsidiaries in Mexico. The audit resulted in a tax assessment that denied the deduction for all interest expense and an assessment of additional tax, penalties and financial charges totaling less than US$1 million. The Company disagreed with this assessment and commenced litigation to challenge it. In January 2022, TC Energy received the tax court's ruling on the 2013 tax return, which upheld the SAT assessment. From September 2021 to February 2022, the SAT issued assessments for tax years 2014 through 2017 which denied the deduction of all interest expense as well as assessed incremental withholding tax on the interest. These assessments totaled approximately US$490 million in income and withholding taxes, interest, penalties and other financial charges.

During 2022, TC Energy settled with the SAT on all of the above matters for the tax years 2013 through 2021 and recorded $196 million (US$153 million) of income tax expense, inclusive of withholding taxes, interest, penalties and other financial charges for the year ended December 31, 2022.

20. LONG-TERM DEBT

at December 31 (millions of Canadian $, unless otherwise noted)	Maturity Dates	2024 Outstanding	2024 Interest Rate[1]	2023 Outstanding	2023 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Medium Term Notes					
Canadian	2025 to 2052	**13,141**	**4.7%**	15,466	4.6%
Senior Unsecured Notes					
U.S. (2024 – US$11,792; 2023 – US$16,167)	2025 to 2049	**16,985**	**5.5%**	21,349	5.0%
		30,126		36,815	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian		**—**	**—**	100	9.9%
Medium Term Notes					
Canadian	2025 to 2030	**504**	**7.4%**	504	7.4%
U.S. (2024 and 2023 – US$33)	2026	**47**	**7.5%**	43	7.5%
		551		647	
COLUMBIA PIPELINES OPERATING COMPANY LLC					
Senior Unsecured Notes					
U.S. (2024 – US$6,500; 2023 – US$6,100)	2025 to 2063	**9,362**	**6.0%**	8,055	6.1%
COLUMBIA PIPELINES HOLDING COMPANY LLC					
Senior Unsecured Notes					
U.S. (2024 – US$1,900; 2023 – US$1,000)	2026 to 2034	**2,737**	**5.9%**	1,320	6.2%
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2024 – US$1,047; 2023 – US$1,172)	2025 to 2037	**1,509**	**3.7%**	1,548	4.1%
TC PIPELINES, LP					
Senior Unsecured Notes					
U.S. (2024 and 2023 – US$850)	2025 to 2027	**1,224**	**4.2%**	1,122	4.2%
GAS TRANSMISSION NORTHWEST LLC					
Senior Unsecured Notes					
U.S. (2024 and 2023 – US$375)	2030 to 2035	**540**	**4.4%**	495	4.4%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM[2]					
Senior Unsecured Notes					
U.S. (2024 – nil; 2023 – US$250)		**—**	**—**	330	2.8%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. (2024 – US$104; 2023 – US$125)	2028 to 2030	**150**	**7.6%**	165	7.6%

at December 31 (millions of Canadian $, unless otherwise noted)	Maturity Dates	2024 Outstanding	2024 Interest Rate[1]	2023 Outstanding	2023 Interest Rate[1]
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.					
Senior Unsecured Term Loan					
U.S. (2024 – US$1,370; 2023 – US$1,800)	2028	**1,973**	**7.2%**	2,377	7.7%
Senior Unsecured Revolving Credit Facility					
U.S. (2024 – nil; 2023 – US$185)	2028	**—**	**—**	244	7.7%
		1,973		2,621	
		48,172		53,118	
Current portion of long-term debt		**(2,955)**		(2,938)	
Unamortized debt discount and issue costs		**(252)**		(312)	
Fair value adjustments[3]		**11**		108	
		44,976		49,976	

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 On August 15, 2024, US$250 million of senior notes outstanding held at PNGTS were assumed by the purchaser as part of the sale of PNGTS. Refer to Note 30, Strategic alliance, acquisitions and dispositions, for additional information.

3 The fair value adjustments include $109 million (2023 – $119 million) related to the acquisition of Columbia Pipeline Group, Inc. These adjustments also include a decrease of $139 million (2023 – $11 million) related to hedged interest rate risk and an increase of $41 million (2023 - nil) related to discontinued hedge interest rate risk. Refer to Note 28, Risk management and financial instruments, for additional information.

Principal Repayments

At December 31, 2024, principal repayments for the next five years on the Company's long-term debt are approximately as follows:

(millions of Canadian $)	2025	2026	2027	2028	2029
Principal repayments on long-term debt	2,955	2,810	3,158	6,083	1,333

Long-Term Debt Issued

The Company issued long-term debt over the three years ended December 31, 2024 as follows:

(millions of Canadian $, unless otherwise noted) Company	Issue Date	Type	Maturity Date	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED					
	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
	May 2022	Medium Term Notes	May 2032	800	5.33%
	May 2022	Medium Term Notes	May 2026	400	4.35%
	May 2022	Medium Term Notes	May 2052	300	5.92%
COLUMBIA PIPELINES OPERATING COMPANY LLC					
	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%
COLUMBIA PIPELINES HOLDING COMPANY LLC					
	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%
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
ANR PIPELINE COMPANY					
	May 2022	Senior Unsecured Notes	May 2032	US 300	3.43%
	May 2022	Senior Unsecured Notes	May 2034	US 200	3.58%
	May 2022	Senior Unsecured Notes	May 2037	US 200	3.73%
	May 2022	Senior Unsecured Notes	May 2029	US 100	3.26%

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, 2024 as follows:

(millions of Canadian $, unless otherwise noted)				
Company	**Retirement/ Repayment Date**	**Type**	**Amount**	**Interest Rate**
TRANSCANADA PIPELINES LIMITED				
	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%
	December 2022	Medium Term Notes	25	9.95%
	August 2022	Senior Unsecured Notes	US 1,000	2.50%
NOVA GAS TRANSMISSION LTD.				
	March 2024	Debentures	100	9.90%
	April 2023	Debentures	US 200	7.88%
ANR PIPELINE COMPANY				
	February 2024	Senior Unsecured Notes	US 125	7.38%
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.				
	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 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.

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.

Interest Expense

year ended December 31 (millions of Canadian $)	2024	2023	2022
Interest on long-term debt	**2,800**	2,562	1,883
Interest on junior subordinated notes	**638**	617	543
Interest on short-term debt	**60**	165	153
Capitalized interest	**(191)**	(187)	(27)
Amortization and other financial charges[1]	**158**	106	36
Gain on debt extinguishment	**(228)**	—	—
	3,237	3,263	2,588
Interest allocated to discontinued operations (Note 4)	**(218)**	(297)	(288)
	3,019	2,966	2,300

1 Amortization and other financial charges include amortization of transaction costs and debt discounts calculated using the effective interest method and losses on derivatives used to manage the Company's exposure to changes in interest rates.

The Company made interest payments of $3,398 million in 2024 (2023 – $2,931 million; 2022 – $2,478 million) on long-term debt, junior subordinated notes and short-term debt, net of interest capitalized.

21. JUNIOR SUBORDINATED NOTES

at December 31		2024		2023	
(millions of Canadian $, unless otherwise noted)	Maturity Date	Outstanding	Effective Interest Rate[1]	Outstanding	Effective Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
US$1,000 issued 2007 at 6.35%[2]	2067	**1,440**	**6.2%**	1,320	6.5%
US$750 issued 2015 at 5.88%[3,4]	2075	**1,080**	**7.5%**	990	7.8%
US$1,200 issued 2016 at 6.13%[3,4]	2076	**1,729**	**8.0%**	1,585	8.3%
US$1,500 issued 2017 at 5.55%[3,4]	2077	**2,161**	**7.2%**	1,981	7.5%
$1,500 issued 2017 at 4.90%[3,4]	2077	**1,500**	**6.8%**	1,500	7.0%
US$1,100 issued 2019 at 5.75%[3,4]	2079	**1,584**	**7.7%**	1,453	8.0%
$500 issued 2021 at 4.45%[3,5]	2081	**500**	**5.7%**	500	5.7%
US$800 issued 2022 at 5.85%[3,5]	2082	**1,152**	**7.3%**	1,056	7.1%
		11,146		10,385	
Unamortized debt discount and issue costs		**(98)**		(98)	
		11,048		10,287	

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 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.
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 10 years and resets every five years thereafter.

The Junior subordinated notes are subordinated in right of payment to existing and future senior indebtedness or other obligations of TCPL.

In March 2022, TransCanada Trust (the Trust) issued US$800 million of Trust Notes – Series 2022-A to investors with a fixed interest rate of 5.60 per cent per annum for the first 10 years and resetting on the 10th anniversary and every five years thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for US$800 million of junior subordinated notes of TCPL at an initial fixed rate of 5.85 per cent per annum, including a 0.25 per cent administration charge. The rate on the junior subordinated notes of TCPL will reset every five years commencing March 2032 until March 2052 to the then Five-Year Treasury Rate, as defined in the document governing the subordinated notes, plus 4.236 per cent per annum; from March 2052 until March 2082, the interest rate will reset every five years to the then Five-Year Treasury Rate plus 4.986 per cent per annum. The junior subordinated notes are callable at TCPL's option at any time from December 7, 2031 to March 7, 2032 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 notes issued between the Trust and TCPL (the Trust Notes) and related agreements, in certain circumstances: 1) TCPL may issue deferral preferred shares to holders of the Trust Notes in lieu of interest; and 2) TC Energy and TCPL would be prohibited from declaring or paying dividends on or redeeming their outstanding preferred shares (or, if none are outstanding, their respective common shares) until all deferral preferred shares are redeemed by TCPL. The Trust Notes may also be automatically exchanged for preferred shares of TCPL upon certain kinds of bankruptcy and insolvency events. All of these preferred shares would rank equally with any other outstanding first preferred shares of TCPL.

22. FOREIGN EXCHANGE (GAINS) LOSSES, NET

year ended December 31 (millions of Canadian $)	2024	2023	2022
Derivative instruments held for trading (Note 28)	**418**	(401)	151
Other	**(271)**	81	34
	147	(320)	185

23. 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:

	Non-Controlling Interests Ownership at	Income (Loss) Attributable to Non-Controlling Interests			Non-Controlling Interests	
		year ended December 31			at December 31	
(millions of Canadian $)	December 31, 2024	2024	2023	2022	2024	2023
Columbia Gas and Columbia Gulf	40% [1]	**571**	143	—	**9,844**	9,167
Portland Natural Gas Transmission System	nil [1]	**30**	41	37	**—**	106
Texas Wind Farms	100% [1,2]	**(29)**	(38)	—	**168**	182
TGNH	13.01% [1]	**109**	—	—	**756**	—
		681	146	37	**10,768**	9,455

1 Refer to Note 30, Strategic alliance, 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.

24. COMMON SHARES

	Number of Shares (thousands)	Amount (millions of Canadian $)
Outstanding at January 1, 2022	980,816	26,716
Issued under public offering[1]	28,400	1,754
Dividend reinvestment and share purchase plan	5,916	342
Exercise of options	2,830	183
Outstanding at December 31, 2022	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**

1 Net of underwriting commissions and deferred income taxes.

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. Refer to Note 1, Description of TC Energy's business, for additional information.

Common Shares Issued Under Public Offering

On August 10, 2022, TC Energy issued 28,400,000 common shares at a price of $63.50 each for total gross proceeds of approximately $1.8 billion.

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.

For the periods between January 1, 2021 and August 31, 2022, and 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)	**2024**	**2023**	**2022**
Basic	**1,038**	1,030	995
Diluted	**1,038**	1,030	996

Stock Options

	Number of Options (thousands)	**Weighted Average Exercise Prices**	**Weighted Average Remaining Contractual Life** (years)
Options outstanding at January 1, 2024	**7,436**	**$62.36**	
Options exercised	**(363)**	**$56.85**	
Options forfeited/expired	**(598)**	**$63.70**	
Options Outstanding at September 30, 2024	**6,475**	**$62.54**	**3.5**
Options Exercisable at September 30, 2024	**4,975**	**$63.54**	**3.0**
Options cancelled on October 1, 2024	**(6,475)**	**$62.54**	
Options issued on October 1, 2024	**5,889**	**$59.72**	
Options exercised	**(1,244)**	**$54.49**	
Options forfeited/expired	**(171)**	**$72.17**	
Options Outstanding at December 31, 2024	**4,474**	**$60.69**	**3.6**
Options Exercisable at December 31, 2024	**3,169**	**$62.50**	**3.1**

On October 1, 2024, as part of the Spinoff Transaction, all outstanding TC Energy stock options were cancelled and an equivalent number of new TC Energy stock options were issued to applicable remaining TC Energy employees and former TC Energy employees (other than those transferred to South Bow pursuant to the Spinoff Transaction) who still held TC Energy stock options. The exercise prices of the new TC Energy stock options were adjusted for the change in value of the TC Energy common shares following the Spinoff Transaction. No other stock options were granted in 2024.

At December 31, 2024, an additional 3,621,343 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	2024[1]	2023	2022
Weighted average fair value	—	$7.88	$8.24
Expected life (years)[2]	—	5.1	5.4
Interest rate	—	2.9%	1.6%
Volatility[3]	—	24%	22%
Dividend yield	—	6.3%	5.5%

1 Commencing in 2024, the Company no longer issues stock options to employees or officers.
2 Expected life is based on historical exercise activity.
3 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 $6 million in 2024 (2023 – $9 million; 2022 – $10 million). At December 31, 2024, unrecognized compensation costs related to non-vested stock options were less than $1 million. The cost is expected to be fully recognized over a weighted average period of 0.7 years.

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian $, unless otherwise noted)	2024	2023	2022
Total intrinsic value of options exercised	**17**	—	33
Total fair value of options that have vested	**99**	76	89
Total options vested	**1.5 million**	1.5 million	1.6 million

As at December 31, 2024, the aggregate intrinsic values of the total options exercisable and the total options outstanding were $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.

25. PREFERRED SHARES

at December 31, 2024	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] (millions of Canadian $) 2024	2023	2022
Cumulative First Preferred Shares									
Series 1	18,424	4.94% [4]	$1.23475	$25.00	December 31, 2029	Series 2	**456**	360	360
Series 2	3,576	Floating [5]	Floating	$25.00	December 31, 2029	Series 1	**83**	179	179
Series 3	9,997	1.69%	$0.4235	$25.00	June 30, 2025	Series 4	**246**	246	246
Series 4	4,003	Floating [5]	Floating	$25.00	June 30, 2025	Series 3	**97**	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**	442	442
Series 10	1,297	Floating [5]	Floating	$25.00	October 30, 2029	Series 9	**32**	—	—
Series 11	10,000	3.35%	$0.83775	$25.00	November 28, 2025	Series 12	**244**	244	244
							2,499	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), 2.35 per cent (Series 10), or 2.96 per cent (Series 12). 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), 2.35 per cent (Series 9), or 2.96 per cent (Series 11).

3 Net of underwriting commissions and deferred income taxes.

4 The fixed rate dividend 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 is 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 5.40 per cent for the period starting December 31, 2024 to, but excluding, March 31, 2025. The floating quarterly dividend rate for the Series 4 preferred shares is 4.76 per cent for the period starting December 31, 2024 to, but excluding, March 31, 2025. The floating quarterly dividend rate for the Series 6 preferred shares is 5.52 per cent for the period starting October 30, 2024 to, but excluding, January 30, 2025 The floating quarterly dividend rate for the Series 10 preferred shares is 6.33 per cent for the period starting October 30, 2024 to, but excluding, January 30, 2025. These rates will reset each quarter going forward.

The holders of preferred shares are entitled to receive a fixed cumulative quarterly preferential dividend as and when declared by the Board with the exception of Series 2, Series 4, Series 6 and Series 10 preferred shares. The holders of Series 2, Series 4, Series 6 and Series 10 preferred shares are entitled to receive quarterly floating rate cumulative preferential dividends 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 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.

On May 31, 2022, TC Energy redeemed all 40,000,000 issued and outstanding Series 15 preferred shares at a redemption price of $25.00 per share and paid the final quarterly dividend of $0.30625 per Series 15 preferred share, for the period up to but excluding May 31, 2022. The Company used the proceeds from the March 2022 issuance of US$800 million of junior subordinated notes through the Trust to finance this preferred share redemption.

26. 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, 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) 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	**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 30, Strategic alliance, 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)

year ended December 31, 2022 (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	1,410	84	1,494
Change in fair value of net investment hedges	(48)	12	(36)
Change in fair value of cash flow hedges	(58)	19	(39)
Reclassification to net income of (gains) losses on cash flow hedges	63	(21)	42
Unrealized actuarial gains (losses) on pension and other post-retirement benefit plans	81	(18)	63
Reclassification to net income of actuarial (gains) losses on pension and other post-retirement benefit plans	9	(3)	6
Other comprehensive income (loss) on equity investments	1,156	(289)	867
Other Comprehensive Income (Loss)	2,613	(216)	2,397

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, 2022	(1,009)	(112)	(113)	(200)	(1,434)
Other comprehensive income (loss) before reclassifications[1]	1,450	(39)	63	870	2,344
Amounts reclassified from AOCI	—	42	6	(3)	45
Net current period other comprehensive income (loss)	1,450	3	69	867	2,389
AOCI balance at December 31, 2022	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[3,4]	**(15)**	**(16)**	**(6)**	**(15)**	**(52)**
Net current period other comprehensive income (loss)	**677**	**19**	**77**	**173**	**946**
Impact of non-controlling interest[5]	**(21)**	**—**	**—**	**—**	**(21)**
Impact of spinoff of Liquids Pipelines business[6]	**(741)**	**—**	**—**	**—**	**(741)**
AOCI balance at December 31, 2024	**(402)**	**(16)**	**22**	**629**	**233**

1 Other comprehensive income(loss) before reclassifications of currency translation adjustments are net of non-controlling interest gains of $903 million (2023 – losses of $366 million; 2022 – gains of $8 million).

2 Represents the AOCI attributable to the 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf upon its sale on October 4, 2023. Refer to Note 30, Strategic alliance, acquisitions and dispositions, for additional information.

3 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 $5 million ($4 million, net of tax) at December 31, 2024. 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.

4 Includes the controlling interest of the AOCI attributable to PNGTS recognized in Net gain (loss) on sale of assets upon the sale of PNGTS on August 15, 2024. Refer to Note 30, Strategic alliance, acquisitions and dispositions, for additional information.

5 Represents the AOCI attributable to CFE's 13.01 per cent non-controlling equity interest in TGNH. Refer to Note 30, Strategic alliance, acquisitions and dispositions, for additional information.

6 Represents the AOCI attributable to the Spinoff Transaction. Refer to Note 4, Discontinued operations, for additional information.

Details about reclassifications out of AOCI into the Consolidated statement of income were as follows:

year ended December 31	Amounts reclassified from AOCI[1]			
(millions of Canadian $)	**2024**	**2023**	**2022**	**Affected line item in the Consolidated statement of income**
Cash flow hedges				
Commodities	**32**	(85)	(47)	Revenues (Power and Energy Solutions)
Interest rate	**(12)**	(12)	(16)	Interest expense
	20	(97)	(63)	Total before tax
	(4)	23	21	Income tax (expense) recovery
	16	(74)	(42)	Net of tax
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial gains (losses)	**6**	—	(11)	Plant operating costs and other[2]
Settlement gain (loss)	**—**	—	2	Plant operating costs and other[2]
	6	—	(9)	Total before tax
	—	—	3	Income tax (expense) recovery
	6	—	(6)	Net of tax
Equity investments				
Equity income (loss)	**19**	22	4	Income (loss) from equity investments
	(4)	(6)	(1)	Income tax (expense) recovery
	15	16	3	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 Amounts in parentheses indicate expenses to the Consolidated statement of income.

2 These AOCI components are included in the computation of net benefit cost. Refer to Note 27, Employee post-retirement benefits, for additional information.

27. 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. In 2023, TC Energy announced a plan amendment to the Canadian OPEB Plan. This plan will be closed 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 nine years at December 31, 2024 (2023 – nine years; 2022 – 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 12 years at December 31, 2024 (2023 – 12 years and 2022 – 12 years). In 2024, the Company expensed $71 million (2023 – $64 million and 2022 – $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 will be prepared in early 2025 outlining the proposed transfer of assets from TC Energy to South Bow. The Canadian DB Plan's assets to be transferred to South Bow are subject to regulatory approval and will be transferred when approval is received. As at December 31, 2024, these assets remain in the TC Energy DB Plan trust and have been reflected as Long-term assets of discontinued operations and a corresponding obligation to South Bow has been reflected as Long-term liabilities of discontinued operations on the Consolidated balance sheet. The assets related to the U.S. DB Plan were fully transferred to South Bow as at December 31, 2024.

Total cash contributions by the Company for employee post-retirement benefits were as follows:

year ended December 31 (millions of Canadian $)	**2024**	**2023**	**2022**
DB Plans	**—**	28	78
Other post-retirement benefit plans	**8**	9	8
Savings and DC Plans	**71**	64	64
	79	101	150

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, 2024 was $111 million (2023 – $244 million; 2022 – $322 million).

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2024 and the next required valuation is at January 1, 2025.

The Company's funded status was comprised of the following:

at December 31 (millions of Canadian $)	Pension Benefit Plans 2024	Pension Benefit Plans 2023	Other Post-Retirement Benefit Plans 2024	Other Post-Retirement Benefit Plans 2023
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**3,356**	3,081	**285**	310
Service cost	**108**	93	**1**	3
Interest cost	**160**	158	**14**	16
Employee contributions	**11**	7	**2**	2
Benefits paid	**(194)**	(185)	**(24)**	(44)
Actuarial (gain) loss	**(39)**	219	**(5)**	2
South Bow - transition of benefit obligation[2]	**(118)**	—	**(1)**	—
Foreign exchange rate changes	**58**	(17)	**16**	(4)
Benefit obligation – end of year	**3,342**	3,356	**288**	285
Change in Plan Assets				
Plan assets at fair value – beginning of year	**3,697**	3,481	**358**	354
Actual return on plan assets	**485**	385	**17**	24
Employer contributions[3,4]	**—**	28	**(41)**	9
Employee contributions	**11**	7	**2**	2
Benefits paid	**(194)**	(185)	**(25)**	(23)
South Bow - transition of plan assets[2]	**(119)**	—	**—**	—
Foreign exchange rate changes	**68**	(19)	**28**	(8)
Plan assets at fair value – end of year	**3,948**	3,697	**339**	358
Funded Status – Plan Surplus	**606**	341	**51**	73

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 Reflects the impact of the Spinoff Transaction of the Liquids Pipelines business on October 1, 2024.
3 The Company reduced letters of credit by $133 million in the Canadian DB Plan (2023 – $78 million) for funding purposes.
4 OPEB surplus of $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 2024	Pension Benefit Plans 2023
TC Energy plan assets at fair value	**3,948**	3,697
South Bow plan assets held in trust[1]	**110**	—
Plan assets at fair value – end of year	**4,058**	3,697

1 Related to the transfer of pension assets to South Bow. The final transfer will be adjusted for investment returns and benefit payments from October 1, 2024 to the transfer date. The $110 million is reflected in Long-term assets of discontinued operations.

The actuarial gain realized on the defined benefit plan obligation is primarily attributable to an increase in the weighted average discount rate from 4.75 per cent in 2023 to 4.90 per cent in 2024.

The actuarial gain realized on the OPEB Plan obligation is primarily due to an increase in the weighted average discount rate from 5.10 per cent in 2023 to 5.45 per cent in 2024.

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 $)	2024	2023	2024	2023
Other long-term assets (Note 15)	**606**	341	**152**	177
Accounts payable and other	**—**	—	**(7)**	(7)
Other long-term liabilities (Note 18)	**—**	—	**(94)**	(97)
	606	341	**51**	73

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 $)	2024	2023	2024	2023
Projected benefit obligation[1]	**—**	—	**(101)**	(104)
Plan assets at fair value	**—**	—	**—**	—
Funded Status – Plan Deficit	**—**	—	**(101)**	(104)

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 $)	2024	2023
Accumulated benefit obligation	**(3,097)**	(3,090)
Plan assets at fair value[1]	**4,058**	3,697
Funded Status – Plan Surplus	**961**	607

1 Includes an estimated $110 million for future transfer to South Bow. The final transfer will be adjusted for investment returns and benefit payments from October 1, 2024, the date of the Spinoff Transaction to the transfer date.

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, 2024 and December 31, 2023.

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
	2024	2023	2024
Fixed income securities	**37%**	41%	**25% to 50%**
Equity securities	**49%**	44%	**25% to 55%**
Other investments	**14%**	15%	**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 $)	**2024**	**2023**	**2024**	**2023**
Fixed income securities	**44**	7	**1.1 %**	0.2%
Equity securities	**3**	2	**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 28, Risk management and financial instruments, for additional information.

at December 31	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total		Percentage of Total Portfolio	
(millions of Canadian $)	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023
Asset Category[1]										
Cash and Cash Equivalents	**138**	68	**—**	1	**—**	—	**138**	69	**3**	2
Equity Securities:										
Canadian	**128**	121	**—**	—	**—**	—	**128**	121	**3**	3
U.S.	**1,234**	965	**—**	—	**—**	—	**1,234**	965	**28**	24
International	**182**	167	**209**	187	**—**	—	**391**	354	**9**	9
Global	**—**	—	**100**	74	**—**	—	**100**	74	**2**	2
Emerging	**66**	54	**150**	140	**—**	—	**216**	194	**5**	5
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**55**	266	**—**	—	**55**	266	**1**	7
Provincial	**—**	—	**312**	314	**—**	—	**312**	314	**7**	8
Municipal	**—**	—	**14**	16	**—**	—	**14**	16	**—**	—
Corporate	**—**	—	**323**	143	**—**	—	**323**	143	**7**	4
U.S. Bonds:										
Federal	**151**	185	**255**	240	**—**	—	**406**	425	**9**	10
Municipal	**—**	—	**1**	1	**—**	—	**1**	1	**—**	—
Corporate	**246**	312	**158**	74	**—**	—	**404**	386	**9**	10
International:										
Government	**4**	4	**17**	11	**—**	—	**21**	15	**1**	—
Corporate	**—**	—	**66**	83	**—**	—	**66**	83	**2**	2
Mortgage backed	**37**	43	**23**	17	**—**	—	**60**	60	**1**	1
Net forward contracts	**—**	—	**(201)**	(131)	**—**	—	**(201)**	(131)	**(4)**	(4)
Other Investments:										
Real estate	**—**	—	**—**	—	**276**	283	**276**	283	**6**	7
Infrastructure	**—**	—	**—**	—	**282**	269	**282**	269	**7**	7
Private equity funds	**—**	—	**—**	—	**32**	10	**32**	10	**1**	—
Funds held on deposit	**138**	138	**—**	—	**—**	—	**138**	138	**3**	3
Derivatives	**—**	—	**1**	—	**—**	—	**1**	—	**—**	—
	2,324	2,057	**1,483**	1,436	**590**	562	**4,397**	4,055	**100**	100

1 Includes an estimated $110 million for future transfer to South Bow. The final transfer will be adjusted for investment returns and benefit payments from October 1, 2024, the date of the Spinoff Transaction to the transfer date.

The following table presents the net change in the Level III fair value category:

(millions of Canadian $, pre-tax)	
Balance at December 31, 2022	632
Purchases and sales	(76)
Realized and unrealized gains (losses)	6
Balance at December 31, 2023	562
Purchases and sales	**(15)**
Realized and unrealized gains (losses)	**43**
Balance at December 31, 2024	**590**

In 2025, the Company's expects to make funding contributions of $6 million for the other post-retirement benefit plans, approximately $71 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 2025.

The following are estimated future benefit payments, which reflect expected future service:

at December 31 (millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**
2025	209	24
2026	212	24
2027	216	24
2028	218	24
2029	221	23
2030 to 2034	1,139	110

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, 2024. 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**	
	2024	**2023**	**2024**	**2023**
Discount rate	**4.90%**	4.75%	**5.45%**	5.10%
Rate of compensation increase	**3.05%**	3.20%	**—**	—

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**		
	2024	**2023**	**2022**	**2024**	**2023**	**2022**
Discount rate	**4.75%**	5.15%	3.05%	**5.15%**	5.45%	3.10%
Expected long-term rate of return on plan assets	**6.60%**	6.45%	6.10%	**4.50%**	4.50%	3.25%
Rate of compensation increase	**3.15%**	3.25%	3.00%	**—**	—	—

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 6.15 per cent weighted-average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2025 measurement purposes. The rate was assumed to decrease gradually to 4.85 per cent by 2032 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 $)	**2024**	**2023**	**2022**	**2024**	**2023**	**2022**
Service cost[1]	**108**	93	145	**1**	3	5
Other components of net benefit cost[1]						
Interest cost	**160**	158	125	**14**	16	13
Expected return on plan assets	**(248)**	(234)	(239)	**(14)**	(16)	(14)
Amortization of actuarial loss	**—**	—	10	**—**	—	1
Amortization of regulatory asset	**—**	—	12	**(2)**	—	1
Settlement gain – AOCI	**—**	—	(2)	**—**	—	—
	(88)	(76)	(94)	**(2)**	—	1
Net Benefit Cost Recognized	**20**	17	51	**(1)**	3	6

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	**2024**		**2023**		**2022**	
(millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Net loss (gain)	**(24)**	**—**	71	6	38	24

Pre-tax amounts recognized in OCI were as follows:

year ended December 31	**2024**		**2023**		**2022**	
(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**	**—**	—	—	(10)	(1)
Settlement	**—**	**—**	—	—	2	—
Funded status adjustment	**(101)**	**(6)**	33	(18)	(101)	20
	(95)	**(6)**	33	(18)	(109)	19

In 2022, a settlement occurred for the U.S. DB Plan as a result of lump sum payments made during the year. The impact of the settlement was determined using actuarial assumptions consistent with those employed at December 31, 2022. The settlement gain decreased the U.S. DB Plan's unrealized actuarial gain by $2 million which was included in OCI, and was recorded in net benefit cost in 2022.

28. 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

The physical and transition risks related to climate change could impact commodity prices and fossil fuel supply and demand dynamics 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 its strategic planning process. TC Energy's exposure to climate change-related transition risks and resulting policy changes is managed 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. The Company factors physical and transition risks into capital planning, financial risk management and operational activities and is working towards reducing the GHG emissions intensity of existing operations.

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, cross-currency interest rate swaps and foreign exchange options as appropriate.

The fair values and notional amounts for the derivatives designated as a net investment hedge were as follows:

at December 31	**2024**		**2023**	
(millions of Canadian $, unless otherwise noted)	**Fair Value[1,2]**	**Notional Amount**	**Fair Value[1,2]**	**Notional Amount**
U.S. dollar cross-currency interest rate swaps (maturing 2025)[3]	**(11)**	**US 100**	2	US 200
U.S. dollar foreign exchange options	**—**	**—**	8	US 1,000
	(11)	**US 100**	10	US 1,200

1 Fair value equals carrying value.

2 No amounts have been excluded from the assessment of hedge effectiveness.

3 In 2024 and 2023, 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.

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)	**2024**	**2023**
Notional amount	**26,000 (US 18,000)**	27,800 (US 21,100)
Fair value	**25,700 (US 17,800)**	26,600 (US 20,200)

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, 2024, the Company recorded a $23 million ECL recovery (2023 – $73 million recovery; 2022 - $149 million expense) with respect to the net investment in leases associated with the in-service TGNH pipelines and $1 million ECL expense (2023 – $10 million recovery; 2022 – $14 million expense) for contract assets related to certain other Mexico natural gas pipelines.

Other than the ECL provision noted above, the Company had no significant credit losses at December 31, 2024 and 2023. At December 31, 2024 and 2023, 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 including 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 (millions of Canadian $)	2024 Carrying Amount	2024 Fair Value	2023 Carrying Amount	2023 Fair Value
Long-term debt, including current portion (Note 20)[1,2]	**(47,931)**	**(48,318)**	(52,914)	(52,815)
Junior subordinated notes (Note 21)	**(11,048)**	**(10,824)**	(10,287)	(9,217)
	(58,979)	**(59,142)**	(63,201)	(62,032)

1 Long-term debt is recorded at amortized cost, except for US$2.8 billion (2023 – US$2.0 billion) that is attributed to hedged risk and recorded at fair value.
2 Net income (loss) for 2024 included unrealized gains of $128 million (2023 – unrealized losses of $53 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships.

Available-for-sale assets summary

The following tables summarize additional information about the Company's restricted investments that were classified as available-for-sale assets:

at December 31 (millions of Canadian $)	2024 LMCI Restricted Investments	2024 Other Restricted Investments[1]	2023 LMCI Restricted Investments	2023 Other Restricted Investments[1]
Fair value of fixed income securities[2,3]				
Maturing within 1 year	**—**	**33**	—	35
Maturing within 1-5 years	**3**	**256**	8	241
Maturing within 5-10 years	**1,578**	**—**	1,340	—
Fair value of equity securities[2,4]	**1,070**	**64**	883	50
	2,651	**353**	2,231	326

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.
2 Available-for-sale assets 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 (millions of Canadian $)	2024 LMCI Restricted Investments[1]	2024 Other Restricted Investments[2]	2023 LMCI Restricted Investments[1]	2023 Other Restricted Investments[2]	2022 LMCI Restricted Investments[1]	2022 Other Restricted Investments[2]
Net unrealized gains (losses)	**218**	**9**	179	13	(223)	(7)
Net realized gains (losses)[3]	**3**	**2**	(28)	—	(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, 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 8)					
Commodities[2]	18	—	—	287	305
Foreign exchange	—	—	—	42	42
	18	—	—	329	347
Other long-term assets (Note 15)					
Commodities[2]	9	—	—	104	113
Foreign exchange	—	—	—	9	9
	9	—	—	113	122
Total Derivative Assets	27	—	—	442	469
Accounts payable and other (Note 17)					
Commodities[2]	(1)	—	—	(291)	(292)
Foreign exchange	—	—	(11)	(183)	(194)
Interest rate	—	(21)	—	—	(21)
	(1)	(21)	(11)	(474)	(507)
Other long-term liabilities (Note 18)					
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 balance sheet classification of the fair value of derivative instruments was as follows:

at December 31, 2023 (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 8)					
Commodities[2]	9	—	—	499	508
Foreign exchange	—	—	10	71	81
	9	—	10	570	589
Other long-term assets (Note 15)					
Commodities[2]	3	—	—	86	89
Foreign exchange	—	—	—	30	30
Interest rate	—	36	—	—	36
	3	36	—	116	155
Total Derivative Assets	12	36	10	686	744
Accounts payable and other (Note 17)					
Commodities[2]	(1)	—	—	(382)	(383)
Foreign exchange	—	—	—	(14)	(14)
Interest rate	—	(18)	—	—	(18)
	(1)	(18)	—	(396)	(415)
Other long-term liabilities (Note 18)					
Commodities[2]	—	—	—	(75)	(75)
Foreign exchange	—	—	—	(2)	(2)
Interest rate	—	(29)	—	—	(29)
	—	(29)	—	(77)	(106)
Total Derivative Liabilities	(1)	(47)	—	(473)	(521)
Total Derivatives	11	(11)	10	213	223

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.

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 $)	2024	2023	2024	2023
Long-term debt	**(3,935)**	(2,630)	**98**	11

1 At December 31, 2024, adjustments for discontinued hedging relationships included in this balance was a liability of $41 million (2023 – nil).

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, 2024	Power	Natural Gas	Foreign Exchange	Interest Rate
Net sales[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.

at December 31, 2023	Power	Natural Gas	Foreign Exchange	Interest Rate
Net sales[1]	9,209	50	—	—
Millions of U.S. dollars	—	—	4,978	2,000
Millions of Mexican pesos	—	—	20,000	—
Maturity dates	2024-2044	2024-2029	2024-2026	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 $)	2024	2023	2022
Derivative Instruments Held for Trading[1]			
Unrealized gains (losses) in the year			
Commodities[2]	**(71)**	132	(11)
Foreign exchange (Note 22)	**(266)**	246	(149)
Interest rate	**(71)**	—	—
Realized gains (losses) in the year			
Commodities	**199**	192	46
Foreign exchange (Note 22)	**(152)**	155	(2)
Interest rate	**29**	—	—
Derivative Instruments in Hedging Relationships			
Realized gains (losses) in the year			
Commodities	**33**	(2)	(73)
Interest rate	**(52)**	(43)	(3)

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 held-for-trading derivative instruments are included on a net basis in Foreign exchange (gains) losses, net in the Consolidated statement of income. Realized and unrealized gains (losses) on interest rate derivatives are included on a net basis in Interest expense in the Consolidated statement of income.

2 In 2024, unrealized gains of $6 million were reclassified to Net Income (loss) from AOCI related to discontinued cash flow hedges (2023 and 2022 – nil).

Derivatives in cash flow hedging relationships

The components of OCI (Note 26) related to the change in fair value of derivatives in cash flow hedging relationships before tax and including the portion attributable to non-controlling interests were as follows:

year ended December 31 (millions of Canadian $, pre-tax)	2024	2023	2022
Gains (losses) in fair value of derivative instruments recognized in OCI[1]			
Commodities	**46**	—	(94)
Interest rate	**—**	—	36
	46	—	(58)

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 $)	2024	2023	2022
Fair Value Hedges			
Interest rate contracts[1]			
Hedged items	**(126)**	(98)	(30)
Derivatives designated as hedging instruments	**(52)**	(43)	(1)
Cash Flow Hedges			
Reclassification of gains (losses) on derivative instruments from AOCI to Net income (loss)[2,3]			
Commodities[4]	**32**	(85)	(47)
Interest rate[1]	**(12)**	(12)	(16)

1 Presented within Interest expense in the Consolidated statement of income.
2 Refer to Note 26, Other comprehensive income (loss) and accumulated other comprehensive income (loss), for the components of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests.
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 2024, unrealized gains of $6 million were reclassified to Net Income (loss) from AOCI related to discontinued cash flow hedges (2023 and 2022– nil).

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, 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.

at December 31, 2023 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative Instrument Assets			
Commodities	597	(418)	179
Foreign exchange	111	(16)	95
Interest rate	36	(5)	31
	744	(439)	305
Derivative Instrument Liabilities			
Commodities	(458)	418	(40)
Foreign exchange	(16)	16	—
Interest rate	(47)	5	(42)
	(521)	439	(82)

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 $133 million and letters of credit of $59 million at December 31, 2024 (2023 – $57 million and $83 million, respectively) to its counterparties. At December 31, 2024, the Company held less than $1 million in cash collateral and $75 million in letters of credit (2023 – less than $1 million and $12 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, 2024, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $10 million (2023 – $3 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, 2024, 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, 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 Company has entered into contracts to sell 50 MW of power commencing in 2025 with terms ranging from 15 to 20 years 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, 2023 (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	387	200	10	597
Foreign exchange	—	111	—	111
Interest rate	—	36	—	36
Derivative Instrument Liabilities				
Commodities	(307)	(130)	(21)	(458)
Foreign exchange	—	(16)	—	(16)
Interest rate	—	(47)	—	(47)
	80	154	(11)	223

1 There were no transfers from Level II to Level III for the year ended December 31, 2023.

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)	2024	2023
Balance at beginning of year	**(11)**	(11)
Net gains (losses) included in Net income (loss)	**54**	(2)
Transfers to Level II	**29**	2
Balance at End of Year[1]	**72**	(11)

1 Revenues include unrealized gains of $54 million attributed to derivatives in the Level III category that were still held at December 31, 2024 (2023 – unrealized losses of $2 million).

29. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian $)	2024[1]	2023[1]	2022[1]
(Increase) decrease in Accounts receivable	**(13)**	(394)	(575)
(Increase) decrease in Inventories	**(16)**	(56)	(190)
(Increase) decrease in Other current assets	**(97)**	618	118
Increase (decrease) in Accounts payable and other	**365**	(206)	(83)
Increase (decrease) in Accrued interest	**(40)**	245	91
(Increase) Decrease in Operating Working Capital	**199**	207	(639)

1 Includes continuing and discontinued operations.

30. STRATEGIC ALLIANCE, 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). TC Energy is providing customary transition services and will continue to work jointly with the purchaser to facilitate a safe and orderly transition.

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.

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.

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 in TGNH. The transaction was accounted for as an equity transaction of which $588 million was recognized as 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 is 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.

31. 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 2024 were $347 million (2023 – $335 million; 2022 – $314 million).

The Company has entered into PPAs with solar and wind-power generating facilities ranging from 2025 to 2038 that require the purchase of generated energy and associated environmental attributes. At December 31, 2024, 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, 2024, TC Energy had approximately $1.1 billion of capital expenditure commitments, primarily consisting of:

- $0.4 billion for its U.S. natural gas pipelines, primarily related to construction costs associated with ANR and other pipeline projects
- $0.3 billion for its Canadian natural gas pipelines related to construction costs associated with the Valhalla North and Berland River projects.

Contingencies

TC Energy is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2024, the Company had accrued approximately $8 million (2023 – $19 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. With the potential exception of the matters discussed below, it is the opinion of management that the ultimate resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations. The claims discussed below are material and there is a reasonable possibility of loss; however, they have not been assessed as probable and a reasonable estimate of loss cannot be made.

Coastal GasLink LP

Coastal GasLink LP is in dispute with a number of contractors related to construction of the Coastal GasLink pipeline. Material legal matters pertaining to Coastal GasLink are summarized as follows:

Pacific Atlantic Pipeline Construction Ltd.

Coastal GasLink LP is in arbitration with one of its previous prime contractors, Pacific Atlantic Pipeline Construction Ltd. (PAPC). Coastal GasLink LP terminated its contract with PAPC for cause, due to the failure of PAPC to complete work as scheduled and made a demand on the parental guarantee for payment of the guaranteed obligations. Following Coastal GasLink LP’s demand on the guarantee, in August 2022, PAPC initiated arbitration. As of December 31, 2024, PAPC purports to seek at least $460 million in damages for wrongful termination for cause, termination damages and payments alleged to be outstanding. Coastal GasLink LP disputes the merits of PAPC’s claims and has counterclaimed against PAPC and its parent company and guarantor, Bonatti S.p.A., citing delays and failures by PAPC to perform and manage work in accordance with the terms of its contract. Coastal GasLink LP estimates its damages to be $1.3 billion. PAPC and Bonatti S.p.A. dispute Coastal GasLink LP's claims and assert that Coastal GasLink LP's damages, if any, are subject to a contractual limit of approximately $220 million. The hearing previously scheduled to commence in November 2024 has now been rescheduled to third quarter 2025. At December 31, 2024, the final outcome of this matter cannot be reasonably estimated.

Separately, Coastal GasLink LP has drawn on a $117 million irrevocable standby letter of credit (LOC) provided by PAPC based on a bona fide belief that Coastal GasLink LP’s damages are in excess of the face value of the LOC. PAPC applied for an injunction restraining Coastal GasLink LP from drawing on the LOC pending the completion of the arbitration between Coastal GasLink LP, PAPC and Bonatti S.p.A., but was unsuccessful. Coastal GasLink LP is now able to use the recovered LOC funds. PAPC and Bonatti S.p.A. have amended their original claims to seek additional damages in relation to the draw on the LOC. The amount claimed has not been articulated beyond the $117 million. The parties have agreed that the issue of damages arising from Coastal GasLink LP's draw on the LOC will be determined, if necessary, at a date subsequent to the arbitration hearing noted above.

Macro Spiecapag Coastal GasLink Joint Venture

Coastal GasLink LP is in arbitration with its former prime contractor, Macro Spiecapag Coastal GasLink Joint Venture (MSJV). In May 2021, Coastal GasLink LP terminated a portion of the work under its contract with MSJV. MSJV continued as prime contractor for the remaining portion of the work; however, it did not complete the remaining work as scheduled. Coastal GasLink LP claims damages in the approximate amount of $560 million for delay, owner indirect costs, contractor replacement costs and repayment of payments made on a without prejudice basis. MSJV has counterclaimed against Coastal GasLink LP for damages for wrongful termination and outstanding costs in the approximate amount of $480 million. An arbitration schedule is expected to be established in second quarter 2025. At December 31, 2024, the final outcome of this matter cannot be reasonably estimated.

2016 Columbia Pipeline Acquisition Lawsuit

In 2023, the Delaware Chancery Court (the Court) issued its decision in the class action lawsuit commenced by former shareholders of Columbia Pipeline Group Inc. (CPG) related to the acquisition of CPG by TC Energy in 2016. 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.

On May 15, 2024, the Court allocated responsibility for the total sale process damages of US$398 million in the amount of 50 per cent to the former Columbia CEO and CFO, collectively, and 50 per cent to TC Energy. Pursuant to the Final Order and Judgment (Final Judgment), TC Energy’s allocated share of the sale process claim damages is US$199 million, plus US$153 million in interest as of June 14, 2024. The Court also entered judgment related to a disclosure claim for which TC Energy’s allocated share of damages is US$84 million, plus US$64 million in interest as of June 14, 2024. The damages for the two claims are not cumulative and TC Energy would only be required to pay the greater of the sale process damages and disclosure claim damages after final determination of those amounts on appeal, including any additional interest assessed to the date of payment.

TC Energy disagrees with many of the Court’s findings and believes the Court’s ruling departs from established Delaware law. TC Energy has filed a notice of appeal, which is scheduled to be heard by the Delaware Supreme Court on March 12, 2025. A final decision is expected in mid-2025. During the appeal process, in lieu of paying the judgment, TC Energy posted an appeal bond in the amount of US$380 million, which approximates the amount of the Final Judgment plus nine months of post-judgment interest. The Company’s legal assessment is that it is not probable that TC Energy will incur a loss upon completion of the appeal process, and therefore, the Company has not accrued a provision for this claim at December 31, 2024.

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		**2024**		**2023**	
(millions of Canadian $)	**Term**	**Potential Exposure**[1]	**Carrying Value**	**Potential Exposure**[1]	**Carrying Value**
Sur de Texas	Renewable to 2053	**93**	**—**	97	—
Bruce Power	Renewable to 2065	**88**	**—**	88	—
Other jointly-owned entities	to 2032	**59**	**1**	24	1
		240	**1**	209	1

1 TC Energy's share of the potential estimated current or contingent exposure.

32. 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 $)	2024[1]	2023[2]
ASSETS		
Current Assets		
Cash and cash equivalents	**311**	188
Accounts receivable	**839**	473
Inventories	**205**	90
Other current assets	**121**	49
Current assets of discontinued operations	**—**	5
	1,476	805
Plant, Property and Equipment	**49,904**	27,477
Equity Investments	**865**	823
Restricted Investments	**950**	—
Goodwill	**479**	439
Regulatory Assets	**53**	12
Other Long-Term Assets	**59**	—
Long-Term Assets of Discontinued Operations	**—**	172
	53,786	29,728
LIABILITIES		
Current Liabilities		
Accounts payable and other	**1,866**	1,092
Accrued interest	**202**	210
Current portion of long-term debt	**2,062**	28
Current liabilities of discontinued operations	**—**	43
	4,130	1,373
Regulatory Liabilities	**1,232**	280
Other Long-Term Liabilities	**70**	46
Deferred Income Tax Liabilities	**7**	22
Long-Term Debt	**12,387**	11,388
Long-Term Liabilities of Discontinued Operations	**—**	10
	17,826	13,119

1 On April 1, 2024, the NGTL System was classified as a VIE when its ownership was transferred from Nova Gas Transmission Ltd. to NGTL GP Ltd. on behalf of NGTL Limited Partnership.

2 Columbia Gas and Columbia Gulf were classified as a VIE upon TC Energy's sale of a 40 per cent non-controlling equity interest on October 4, 2023. Refer to Note 30, Strategic alliance, acquisitions and dispositions, for additional information.

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 $)	2024	2023
Balance Sheet Exposure		
Equity Investments		
Bruce Power	**7,043**	6,241
Coastal GasLink	**1,006**	294
Pipeline equity investments and other	**160**	166
Long-Term Assets of Discontinued Operations		
Pipeline equity investments and other	**—**	951
Off-Balance Sheet Exposure[1]		
Bruce Power	**1,877**	1,538
Coastal GasLink[2]	**265**	855
Pipeline equity investments and other	**2**	2
Discontinued operations	**—**	56
Maximum exposure to loss	**10,353**	10,103

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 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. Refer to Note 7, Coastal GasLink, for additional information.

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

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