U.S. Securities and Exchange Commission

Washington, D.C. 20549

Form 40-F

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

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

For the fiscal year ended December 31, 2023

TC ENERGY CORPORATION

(Commission File Number **1-31690**)

TRANSCANADA PIPELINES LIMITED

(Commission File Number **1-8887**)

(Exact name of Registrant as specified in its charter)

Canada

(Province or other jurisdiction of incorporation or organization)

4922, 4923, 4924, 5172

(Primary Standard Industrial Classification Code Number (if applicable))

Not Applicable
(TC Energy Corporation)

(I.R.S. Employer Identification Number (if applicable))

52-2179728
(TransCanada PipeLines Limited)

(I.R.S. Employer Identification Number (if applicable))

TC Energy Tower, 450 - 1 Street S.W.
Calgary, Alberta, Canada, T2P 5H1
(403) 920-2000

(Address and telephone number of Registrant's principal executive offices)

TransCanada PipeLine USA Ltd., 700 Louisiana Street, Suite 700
Houston, Texas, 77002-2700; (832) 320-5201

(Name, address (including zip code) and telephone number (including area code)
of agent for service in the United States)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Shares (including Rights under Shareholder Rights Plan) of TC Energy Corporation	**TRP**	**New York Stock Exchange**

Securities registered or to be registered pursuant to Section 12(g) of the Act: None
Securities for which there is a reporting obligation pursuant to Section15(d) of the Act:
Debt Securities of TransCanada PipeLines Limited

For annual reports, indicate by check mark the information filed with this Form:

☒ Annual information form ☒ Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the Annual report.

At December 31, 2023, 1,037,487,829 common shares;
14,577,184 Cumulative Redeemable First Preferred Shares, Series 1;
7,422,816 Cumulative Redeemable First Preferred Shares, Series 2;
9,997,177 Cumulative Redeemable First Preferred Shares, Series 3;
4,002,823 Cumulative Redeemable First Preferred Shares, Series 4;
12,070,593 Cumulative Redeemable First Preferred Shares, Series 5;
1,929,407 Cumulative Redeemable First Preferred Shares Series 6;
24,000,000 Cumulative Redeemable First Preferred Shares Series 7;
18,000,000 Cumulative Redeemable First Preferred Shares Series 9; and
10,000,000 Cumulative Redeemable First Preferred Shares, Series 11
of TC Energy Corporation were issued and outstanding.

At December 31, 2023, 992,720,977 common shares of TransCanada PipeLines Limited,
which were all owned by TC Energy Corporation, were issued and outstanding.

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

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

Indicate by check mark whether the Registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.
Emerging growth company ☐

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the Registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act.

†The term "new or revised financial accounting standard" refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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

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

The documents (or portions thereof) forming part of this Form 40-F are incorporated by reference into the following registration statements under the Securities Act of 1933, as amended:

Form	Registration No.
S-8	333-5916
S-8	333-8470
S-8	333-9130
S-8	333-151736
S-8	333-184074
S-8	333-227114
S-8	333-237979
F-3	33-13564
F-3	333-6132
F-10	333-208585
F-10	333-250988
F-10	333-252123
F-10	333-267323
F-10	333-276558

EXPLANATORY NOTE

TransCanada PipeLines Limited ("TransCanada PipeLines") is a wholly owned subsidiary of TC Energy Corporation ("TC Energy"). As of the date of filing of this Form 40-F, TransCanada PipeLines is relying on the continuous disclosure documents filed by TC Energy pursuant to an exemption from the requirements of National Instrument 51-102 - Continuous Disclosure Obligations and as provided in the decision of the Alberta Securities Commission and the Ontario Securities Commission in *Re TransCanada Corporation, 2019 ABASC 1*, issued on January 3, 2019. Consistent with the exemptive relief, information contained in this Form 40-F is that provided by TC Energy except as indicated below.

AUDITED CONSOLIDATED FINANCIAL STATEMENTS AND MANAGEMENT'S DISCUSSION & ANALYSIS

Except sections specifically referenced below which shall be deemed incorporated by reference herein and filed, no other portion of the TC Energy 2023 Management's discussion and analysis and audited consolidated financial statements to shareholders, except as otherwise specifically incorporated by reference in the TC Energy Annual information form, shall be deemed filed with the U.S. Securities and Exchange Commission (the "Commission") as part of this report under the Exchange Act.

A. Audited Consolidated Financial Statements

For audited consolidated financial statements, including the auditors' report, see pages 135 through 225 of the TC Energy 2023 Management's discussion and analysis and audited consolidated financial statements included herein.

B. Management's Discussion and Analysis

For management's discussion and analysis, see pages 9 through 134 of the TC Energy 2023 Management's discussion and analysis and audited consolidated financial statements included herein under the heading "Management's discussion and analysis".

C. Management's Report on Internal Control over Financial Reporting

For management's report on internal control over financial reporting, see "Management's Report on Internal Control over Financial Reporting" that accompanies the audited consolidated financial statements on page 135 of the TC Energy 2023 Management's discussion and analysis and audited consolidated financial statements included herein.

UNDERTAKING

Each Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

For information on disclosure controls and procedures and management's annual report on internal control over financial reporting, see "Other information - Controls and Procedures" on page 115 of the TC Energy 2023 Management's discussion and analysis and audited consolidated financial statements.

AUDIT COMMITTEE FINANCIAL EXPERT

Each Registrant's Board of Directors has determined that it has at least one audit committee financial expert serving on its Audit committee. Ms. Una Power has been designated as an audit committee financial expert and is independent, as that term is defined by the New York Stock Exchange's listing standards applicable to each Registrant. The Commission has indicated that the designation of Ms. Power as an audit committee financial expert does not make Ms. Power an "expert" for any purpose, impose any duties, obligations or liability on Ms. Power that is greater than those imposed on members of the Audit committee and Board of Directors who do not carry this designation or affect the duties, obligations or liability of any other member of the Audit committee.

CODE OF ETHICS

The Registrants have adopted a code of business ethics ("Code") for their directors, officers, employees and contractors. In 2023, the Code was updated with amendments to include the addition of a designated human rights section to capture the UN Global Compact Principles, linking human rights to TC Energy's Commitment Statement, and context regarding company training courses that support human rights awareness. Other minor amendments included additional clarifications regarding conducting outside business activities outside of company work hours and prohibited disclosures of confidential market moving information.

The Registrants' Code is available on TC Energy's website at www.tcenergy.com and any person can obtain the Code without charge upon request from the Corporate Secretary of TC Energy. No waivers have been granted from any provision of the Code during the 2023 fiscal year.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

Our independent registered public accounting firm is KPMG LLP, Calgary, AB, Canada, Auditor Firm ID: 85. For information on principal accountant fees and services, see "Audit committee - Pre-approval Policies and Procedures" and "Audit committee - External Auditor Service Fees" on page 35 of the TC Energy 2023 Annual information form.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrants have no off-balance sheet arrangements, as defined in this Form, other than the guarantees and commitments described in Note 32 of the Notes to the audited consolidated financial statements attached to this Form 40-F and incorporated herein by reference.

DISCLOSURE OF CONTRACTUAL OBLIGATIONS

For information on disclosure of contractual obligations, see "Financial Condition - Contractual obligations" in Management's discussion and analysis on page 96 of the TC Energy 2023 Management's discussion and analysis and audited consolidated financial statements.

IDENTIFICATION OF THE AUDIT COMMITTEE

Each Registrant has a separately-designated standing Audit committee. The members of the Audit committee as of February 15, 2024 (unless otherwise indicated) are:

Chair:	**U. Power**
Members:	**C.F. Campbell**
	M.R. Culbert
	W.D. Johnson
	S.C. Jones

DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not Applicable.

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 included or incorporated by reference in this document 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 about the new Liquids Pipelines Company, South Bow Corporation, following the anticipated completion of the proposed spinoff transaction of our Liquids Pipelines business into a separate publicly listed company, including the management and credit ratings thereof
- expectations regarding the size, structure, timing, conditions and outcome of ongoing and future transactions, including the proposed spinoff transaction and our asset divestiture program
- 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
- statements related to our GHG emissions reduction goals
- 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
- expected industry, market and economic conditions, 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 document.

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, divestitures, the proposed spinoff transaction and energy transition
- regulatory decisions and outcomes
- planned and unplanned outages and the use 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, divestitures, the proposed spinoff transaction and energy transition
- terms, timing and completion of the proposed spinoff transaction, including the timely receipt of all necessary approvals and tax rulings
- that market or other conditions are no longer favourable to completing the proposed spinoff transaction
- business disruption during the period prior to or directly following the proposed 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
- impact of energy transition on our business
- economic conditions 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 reports we have filed with Canadian securities regulators and the Commission.

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.

DOCUMENTS FILED AS PART OF THIS REPORT

EXHIBITS

13.1	TC Energy Corporation Annual information form for the year ended December 31, 2023.
13.2	Management's discussion and analysis (included on pages 9 through 134 of the TC Energy Corporation 2023 Management's discussion and analysis and audited consolidated financial statements to shareholders).
13.3	2023 Audited consolidated financial statements (included on pages 135 through 225 of the TC Energy Corporation 2023 Management's discussion and analysis and audited consolidated financial statements to shareholders), including the Report of Independent Registered Public Accounting Firm on the Consolidated Financial Statements and the Report of Independent Registered Public Accounting Firm on the effectiveness of TC Energy's internal control over financial reporting as of December 31, 2023.
23.1	Consent of KPMG LLP, Chartered Professional Accountants, Independent Registered Public Accounting Firm.
31.1	Certification of Chief Executive Officer regarding Periodic Report containing Financial Statements.
31.2	Certification of Chief Financial Officer regarding Periodic Report containing Financial Statements.
32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
97.1	TC Energy Corporation's Policy Relating to Recovery of Erroneously Awarded Incentive-Based Compensation.
99.1	TC Energy Corporation's Code of Business Ethics Policy, as amended and filed with the Securities and Exchange Commission as part of a Form 6-K report on October 16, 2023, and incorporated by reference herein.
101.SCH	Inline XBRL Taxonomy Extension Schema Document.
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	Inline XBRL Taxonomy Definition Linkbase Document.
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

SIGNATURES

Pursuant to the requirements of the Exchange Act, each Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized, in the City of Calgary, Province of Alberta, Canada.

TC ENERGY CORPORATION
TRANSCANADA PIPELINES LIMITED
(Registrants)

By: /s/ JOEL E. HUNTER
JOEL E. HUNTER
Executive Vice-President and Chief Financial Officer
Date: February 16, 2024

EXHIBIT 13.1

TC Energy Corporation

2023 Annual information form

February 15, 2024



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Presentation of information

Throughout this Annual information form (AIF), the terms, we, us, our, the Company and TC Energy mean TC Energy Corporation and its subsidiaries. In particular, TC Energy includes references to TransCanada PipeLines Limited (TCPL). The term subsidiary, when referred to in this AIF, with reference to TC Energy means direct and indirect wholly-owned subsidiaries of, and legal entities controlled by, TC Energy or TCPL, as applicable.

Unless otherwise noted, the information contained in this AIF is given at or for the year ended December 31, 2023 (Year End). Amounts are expressed in Canadian dollars, unless otherwise indicated. Information in relation to metric conversion can be found at *Schedule A* to this AIF. The *Glossary* found at the end of this AIF contains certain terms defined throughout this AIF and abbreviations and acronyms that may not otherwise be defined in this document.

Certain portions of TC Energy's management's discussion and analysis dated February 15, 2024 (MD&A) are incorporated by reference into this AIF as stated below and noted elsewhere in this AIF. The MD&A can be found on SEDAR+ (www.sedarplus.ca) under TC Energy's profile.

Financial information is presented in accordance with United States (U.S.) generally accepted accounting principles (GAAP).

Forward-looking information

This AIF, including the MD&A disclosure incorporated by reference herein, contains certain information that is forward looking and is subject to important risks and uncertainties. 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 included or incorporated by reference in this AIF 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 about the new Liquids Pipelines Company, South Bow Corporation, following the anticipated completion of the proposed spinoff transaction of our Liquids Pipelines business into a separate publicly listed company, including the management and credit ratings thereof
- expectations regarding the size, structure, timing, conditions and outcome of ongoing and future transactions, including the proposed spinoff transaction and our asset divestiture program
- 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
- statements related to our GHG emissions reduction goals
- 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
- expected industry, market and economic conditions, 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 AIF.

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, divestitures, the proposed spinoff transaction and energy transition
- regulatory decisions and outcomes
- planned and unplanned outages and the use 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, divestitures, the proposed spinoff transaction and energy transition
- terms, timing and completion of the proposed spinoff transaction, including the timely receipt of all necessary approvals and tax rulings
- that market or other conditions are no longer favourable to completing the proposed spinoff transaction
- business disruption during the period prior to or directly following the proposed 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
- impact of energy transition on our business
- economic conditions 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 the 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.

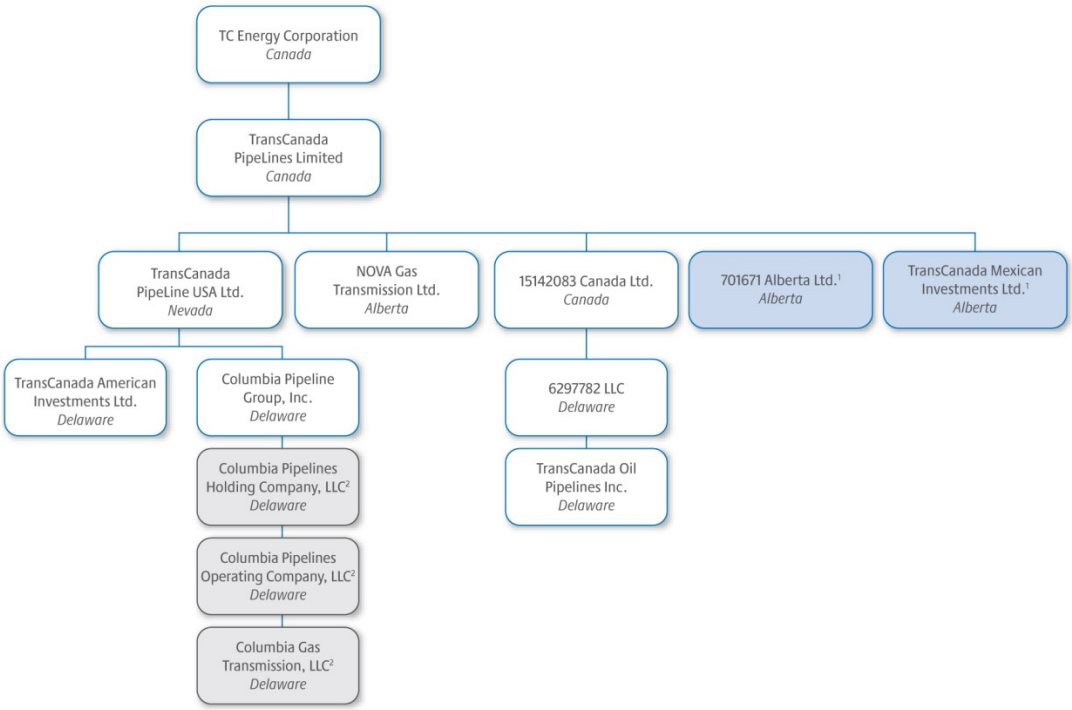
TC Energy Corporation

CORPORATE STRUCTURE

Our head office and registered office are located at 450 – 1 Street S.W., Calgary, Alberta, T2P 5H1. TC Energy was incorporated pursuant to the provisions of the *Canada Business Corporations Act* (CBCA) on February 25, 2003 in connection with a plan of arrangement with TCPL (Arrangement), which established TC Energy as the parent company of TCPL. The Arrangement was approved by TCPL common shareholders on April 25, 2003 and, following court approval and the filing of Articles of Arrangement, the Arrangement became effective on May 15, 2003. TCPL continues to carry on business as the principal operating subsidiary of TC Energy. TC Energy does not hold any material assets directly other than the common shares of TCPL and receivables from certain of TC Energy's subsidiaries.

INTERCORPORATE RELATIONSHIPS

The following diagram presents the name and jurisdiction of incorporation, continuance or formation of TC Energy's principal subsidiaries as at Year End. Each of the subsidiaries shown has total assets that exceeded 10 per cent of the consolidated assets of TC Energy as at Year End or revenues that exceeded 10 per cent of the consolidated revenues of TC Energy as at Year End. Except as otherwise indicated below, TC Energy beneficially owns, controls or directs, directly or indirectly, 100 per cent of the voting shares or units in each of these subsidiaries.



The above diagram does not include all of the subsidiaries of TC Energy. The total assets and revenues of excluded subsidiaries in the aggregate did not exceed 20 per cent of the consolidated assets of TC Energy as at Year End or consolidated revenues of TC Energy as at Year End.

[1] 701671 Alberta Ltd. and TransCanada Mexican Investments Ltd. assets and revenues do not exceed 10 per cent of the total consolidated assets or revenues of TC Energy but have been included to meet the total consolidated revenues and assets criteria of excluded subsidiaries threshold of less than 20 per cent.

[2] TC Energy beneficially owns, controls or directs, directly or indirectly, 60 per cent of the voting shares or units in each of these subsidiaries.

Business of TC Energy

We operate in three core businesses – Natural Gas Pipelines, Liquids 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 five operating segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids 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.

For information regarding our Natural Gas Pipelines business, including pipeline holdings, developments, opportunities, regulation and competitive position refer to the *Natural Gas Pipelines Business*, *Canadian Natural Gas Pipelines*, *U.S. Natural Gas Pipelines* and *Mexico Natural Gas Pipelines* sections of the MD&A, which sections are incorporated by reference herein.

For information regarding our Liquids Pipelines business, including pipeline holdings, developments, opportunities, regulation and competitive position refer to the *Liquids Pipelines* section of the MD&A, which section is incorporated by reference herein.

For information regarding our Power and Energy Solutions business, including holdings, developments, opportunities, regulation and competitive position refer to the *Power and Energy Solutions* section of the MD&A, which section is incorporated by reference herein.

Refer to the *About our business – 2023 Financial highlights- Consolidated results* section of the MD&A for our revenues from operations by segment, for the years ended December 31, 2023 and 2022, which section is incorporated by reference herein.

General development of the business

Summarized below are significant developments that have occurred in our Natural Gas Pipelines, Liquids Pipelines and Power and Energy Solutions businesses, respectively, and certain acquisitions, dispositions, events or conditions which have had an influence on those developments, during the last three financial years and year to date in 2024. Further information about developments in our business, including changes that we expect will occur in 2024, can be found in the *Natural Gas Pipelines Business, Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines, Power and Energy Solutions* and *Secured Projects* sections of the MD&A, which sections are incorporated by reference herein.

NATURAL GAS PIPELINES

Developments in the Canadian Natural Gas Pipelines Segment

CANADIAN REGULATED PIPELINES

2021 NGTL System Expansion Program

The 2021 NGTL System Expansion Program consists of 344 km (214 miles) of new pipeline, three new compressor units and associated facilities and is expected to add 1.59 PJ/d (1.45 Bcf/d) of incremental capacity to the NGTL System. Construction of the expansion program is nearing completion with an estimated capital cost of $3.6 billion. As of December 31, 2023, $3.4 billion of the program's facilities have been placed in service, including all facilities required to declare contracts.

2022 NGTL System Expansion Program

The 2022 NGTL System Expansion Program was completed in 2023 and consists of approximately 166 km (103 miles) of new pipeline, one compressor unit and associated facilities and provides incremental capacity of approximately 773 TJ/d (722 MMcf/d) to meet firm-receipt and intra-basin delivery requirements with eight-year minimum terms. The capital cost of the program was $1.4 billion with all assets placed 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 and is underpinned by approximately 255 TJ/d (238 MMcf/d) of new firm-service contracts with 15-year terms. The estimated capital cost of the expansion is $0.5 billion. Construction activities commenced in 2022 with the pipeline placed in service in late 2023 and construction of the compressor stations is underway with anticipated in-service by second quarter 2024.

NGTL System/Foothills West Path Delivery Program

The NGTL System/Foothills West Path Delivery Program was a multi-year expansion of the NGTL System and Foothills system to facilitate incremental contracted export capacity connecting to the GTN pipeline system. The combined NGTL System and Foothills program consists of approximately 107 km (66 miles) of pipeline and associated facilities and is underpinned by 275 TJ/d (258 MMcf/d) of new firm-service contracts with terms that exceed 30 years. The capital cost of the program was $1.6 billion with all remaining assets placed in service in 2023.

Valhalla North and Berland River Project

In November 2022, we sanctioned the Valhalla North and Berland River (VNBR) project to serve aggregate system requirements and connect migrating supply to key demand markets, providing incremental capacity on the NGTL System of approximately 428 TJ/d (400 MMcf/d) and is expected to contribute to lower GHG emission intensity for the overall system. With an estimated capital cost of $0.6 billion, the project consists of approximately 33 km (21 miles) of new pipeline, one new non-emitting electric compressor unit and associated facilities. On December 21, 2023, we received approval from the CER to construct, own and operate the VNBR project with an anticipated in-service date in second quarter 2026.

Canadian Mainline Settlement

In 2021, the Canadian Mainline began 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.

LNG PIPELINE PROJECTS

Coastal GasLink

In May 2020, we completed the sale of a 65 per cent equity interest in Coastal GasLink Pipeline Limited Partnership (Coastal GasLink LP). As part of the transaction, we were contracted by Coastal GasLink LP to construct and operate the 670 km (416 mile) Coastal GasLink pipeline project to transport natural gas from a receipt point in the Dawson Creek area of British Columbia to LNG Canada's natural gas liquefaction facility near Kitimat, British Columbia. Transportation service on the pipeline is underpinned by 25-year TSAs (with renewal provisions) with each of the five LNG Canada participants.

As a result of scope changes, previous permit delays compared to the original construction schedule and the impacts from COVID-19, including a health order issued by the British Columbia Provincial Health Officer restricting the number of workers on site, project costs increased significantly along with a delay to project completion compared to the original project cost and schedule. Coastal GasLink LP entered into a dispute with LNG Canada with respect to the recognition of certain costs and the impacts on schedule. As an interim measure, TC Energy executed a subordinated loan agreement to provide additional temporary financing to the project, if necessary, of up to $3.3 billion as a bridge to a required increase in the $6.8 billion project-level financing to fund incremental costs.

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. The equity option is exercisable after commercial in-service of the pipeline, subject to customary regulatory approvals and consents, including the consent of LNG Canada.

In July 2022, Coastal GasLink LP executed definitive agreements with LNG Canada, TC Energy and the other Coastal GasLink LP partners (collectively, the July 2022 agreements) that amended existing project agreements to address and resolve disputes over certain incurred and anticipated project costs. The revised agreements incorporated a target date for mechanical completion of December 31, 2023 and a new capital cost for the project to reflect, among other changes, scope increases and the impacts of COVID-19, weather and other events outside the control of Coastal GasLink LP.

Subsequent to execution of the July 2022 agreements, the project faced material cost pressures reflecting challenging conditions in the Western Canadian labour market, shortages of skilled labour, impacts of contractor underperformance and disputes, as well as other unexpected events, including drought conditions and erosion and sediment control challenges. A comprehensive cost and schedule risk analysis (CSRA) was conducted to assess current market conditions and potential risks and uncertainties facing the remaining project scope. As a result of the CSRA, the estimate of the cost to complete the pipeline increased to approximately $14.5 billion, excluding potential cost recoveries and after accounting for contingencies for certain factors that may be outside the control of Coastal GasLink LP, such as labour conditions, contractor underperformance and weather-related events. In connection with the revised estimate, we announced that we expected to fund the incremental project costs and were actively pursuing cost mitigants and recoveries to partially offset a portion of these costs, some of which may not be conclusively determined until after the pipeline is in service.

The expectation that incremental project costs would predominantly be funded by us was an indicator that a decrease in the value of our equity investment had occurred. As a result, a valuation assessment of our equity investment in Coastal GasLink LP was completed, which concluded that there was an other-than-temporary impairment of our investment, resulting in a pre-tax impairment charge of $3.0 billion ($2.6 billion after tax) in fourth quarter 2022. Due to the funding provisions of the July 2022 agreements, we announced that we expected to fund an additional $3.3 billion related to the revised estimated capital cost to complete the Coastal GasLink pipeline, and that a significant portion of our investment in Coastal GasLink LP was expected to be impaired.

In 2022, we further announced that, going forward, project costs would be funded in part by existing project-level credit facilities with a revised total capacity of $8.4 billion and that our portion of the equity contributions to Coastal GasLink LP over the project life was expected to be approximately $5.4 billion, including contributions recognized to the end of 2022.

Beginning in 2023, equity financing required to fund construction of the pipeline to completion is initially provided through a subordinated loan agreement between TC Energy and Coastal GasLink LP (the Subordinated Loan). Draws by Coastal GasLink LP on the Subordinated Loan will be repaid with funds from equity contributions to the partnership by the Coastal GasLink LP partners, including us, subsequent to the in-service date of the Coastal GasLink pipeline when final project costs are known. We expect that, in accordance with contractual terms, the additional equity contributions required as a result of the increase in capital costs will be predominantly funded by us, except under certain circumstances, but will not result in a change to our 35 per cent ownership. At December 31, 2023, committed capacity under the Subordinated Loan was $3,375 million, on which $2,520 million was drawn.

The expectation that additional equity contributions will predominantly be funded by us continued to be an indicator during the first three quarters of 2023 that a decrease in the value of our equity investment had occurred. As a result, we completed further valuation assessments and concluded that there was an other-than-temporary impairment of our investment, resulting in a pre-tax impairment charge of $2,100 million ($1,943 million after tax) for the year ended December 31, 2023. The impairment charge reflected the net impact of changes in the Subordinated Loan for the nine months ended September 30, 2023, along with TC Energy's proportionate share of unrealized gains and losses on interest rate derivatives in Coastal GasLink LP and other changes to the equity investment. The impairment of the Subordinated Loan resulted in unrealized non-taxable capital losses that are not recognized. The cumulative pre-tax impairment charge recognized to date at December 31, 2023 is $5,148 million ($4,586 million after tax). At December 31, 2023, the carrying value of our equity investment in Coastal GasLink LP was $294 million. There was no indicator that there was an other-than-temporary impairment of this investment and no impairment charge was recognized in fourth quarter 2023.

LNG PIPELINE PROJECTS

Coastal GasLink (continued)

The Coastal GasLink pipeline project successfully achieved mechanical completion, completed pipeline commissioning activities and was ready to deliver gas to the LNG Canada facility in fourth quarter 2023. These milestones entitle Coastal GasLink LP to receive a $200 million readiness incentive payment from LNG Canada. In accordance with the contractual terms between the Coastal GasLink LP partners, the amount accrues in full to TC Energy as the project developer and was settled through a cash distribution on February 13, 2024 OR will be settled through a cash distribution in first quarter 2024. Commercial in-service of the Coastal GasLink pipeline will occur after completion of plant commissioning activities at the LNG Canada facility and upon receiving notice from LNG Canada.

Through 2024, Coastal GasLink LP will continue post-construction reclamation activities. Coastal GasLink LP also continues to pursue cost recovery, including certain arbitration proceedings which involve claims by us and our defense of certain claims against us. These claims have not yet been conclusively determined, but our expectation is that these proceedings are likely to result in cost recoveries. The project remains on track with its cost estimate of approximately $14.5 billion.

Developments in the U.S. Natural Gas Pipelines Segment

U.S. NATURAL GAS PIPELINES - COLUMBIA PIPELINE GROUP

Columbia Gas and Columbia Gulf Monetization

On October 4, 2023, we successfully completed the sale of a 40 per cent equity interest in Columbia Gas and Columbia Gulf to Global Infrastructure Partners (GIP) for proceeds of $5.3 billion (US$3.9 billion). Columbia Gas and Columbia Gulf are held by a newly formed entity with GIP. Preceding the close of the equity sale, on August 8, 2023, Columbia Pipelines Operating Company LLC and Columbia Pipelines Holding Company LLC issued US$4.6 billion and US$1.0 billion of long-term, senior unsecured debt, respectively. The net proceeds from the offerings were used to repay existing intercompany indebtedness with TC Energy entities and directed towards reducing leverage. We continue to have a controlling interest in Columbia Gas and Columbia Gulf and we remain the operator of these 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.

Columbia Gas Rate Case Settlement

Columbia Gas filed a Section 4 rate case with FERC in July 2020 requesting an increase to its maximum transportation rates effective February 1, 2021. Columbia Gas reached a settlement with its customers effective February 2021 and received FERC approval in February 2022. 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. Previously accrued rate refund liabilities were refunded to customers, including interest, in second quarter 2022.

Columbia Gas - VR Project

In July 2021, we approved the VR Project, a delivery market project on Columbia Gas designed to replace and upgrade certain facilities while improving reliability and reducing emissions. In November 2023, the FERC provided a certificate order approving the VR Project. The VR Project is subject to customary conditions precedent and normal-course regulatory approvals. It is anticipated to be in-service in late 2025 at an estimated project cost of US$0.7 billion.

Columbia Gas - Modernization III

In 2021, Columbia Gas and its customers entered into a settlement arrangement (Modernization III), which provides recovery and return on investment to modernize its system and improve system safety, integrity, compliance and reliability. The Modernization III program includes, among other things, replacement of aging pipeline and compressor facilities, enhancements to system inspection capabilities and improvements in control systems, as well as projects designed to increase energy efficiency and reduce emissions. The program was approved for up to US$1.2 billion of work starting in 2021 and is expected to be completed in 2024.

Columbia Gas - KO Transmission Enhancement Acquisition

On April 28, 2022, we approved the approximately US$80 million acquisition of KO Transmission assets to be integrated into our Columbia Gas pipeline to provide additional last-mile connectivity of Columbia Gas into northern Kentucky and southern Ohio to growing LDC markets and a platform for future capital investments including future conversions of coal-fueled power plants in the region. FERC approval for the acquisition was received in November 2022 and the transaction closed in February 2023.

Line VB Strasburg

On July 25, 2023, a natural gas pipeline rupture on Columbia Gas occurred alongside Interstate 81 in Strasburg, Virginia. Emergency response procedures were enacted and the segment of impacted pipeline was isolated shortly thereafter. There were no reported injuries involved with this incident and no significant damage to surrounding structures. The pipeline has been operating at reduced pressure in accordance with PHMSA's Corrective Action Order (CAO) since July 28, 2023 and we are working with PHMSA under the CAO to return the system to normal operations as soon as possible. The Root Cause Failure Analysis (RCFA) findings indicated that similar pipeline segment locations within the Columbia Gas pipeline system require further testing.

Columbia Gulf - Louisiana XPress Project

The Louisiana XPress project, a Columbia Gulf project designed to connect natural gas supply to U.S. Gulf Coast LNG export facilities, was phased into service over the course of third quarter 2022.

Virginia Electrification Project

In February 2024, the Virginia Electrification project, an expansion project that replaced and upgraded certain facilities through conversion to electric compression, reducing GHG emissions intensity along portions of our Columbia Gas system, was placed in service.

Columbia Gulf Rate Settlement

On July 7, 2023, Columbia Gulf filed an uncontested rate settlement, which would set new recourse rates for Columbia Gulf effective March 1, 2024 and institute a rate moratorium through February 28, 2027. Columbia Gulf must file for new rates no later than March 1, 2029.

OTHER U.S. NATURAL GAS PIPELINES

ANR Pipeline Company (ANR Pipeline) - Grand Chenier XPress

The Grand Chenier XPress project connects supply directly to Gulf Coast LNG export markets with auxiliary enhancements at its existing Eunice Compressor Station, the addition of a mid-point compressor station and a new point of delivery interconnection, meter and associated facilities along ANR Pipeline. Phase I of Grand Chenier XPress went into service in April 2021. Phase II was placed in service in January 2022.

ANR Pipeline - Alberta XPress Project

The Alberta XPress project, an expansion project on ANR which utilizes existing capacity on the Great Lakes and Canadian Mainline systems to connect growing supply from the WCSB to U.S. Gulf Coast LNG export markets, was placed in service January 2023.

ANR Pipeline - Elwood Power Project/ANR Horsepower Replacement

The Elwood Power Project/ANR Horsepower Replacement, an expansion project to replace, upgrade and modernize certain facilities while improving reliability and reducing GHG emissions along a highly utilized section of the ANR pipeline system, was placed in service in November 2022.

ANR Pipeline - Wisconsin Access Project

The Wisconsin Access project, a project to replace, upgrade and modernize certain facilities while improving reliability and reducing GHG emissions along portions of the ANR pipeline system, was placed in service in November 2022.

ANR Pipeline - WR Project

In November 2021, we approved the WR Project, a delivery market project on ANR to replace and upgrade certain facilities while improving reliability and reducing emissions along portions of the ANR pipeline system in principal delivery markets. In December 2023, the FERC approved the WR Project. It is expected to be in service in late 2025.

ANR Pipeline - Ventura XPress Project

In December 2022, we approved the Ventura XPress Project, a set of ANR projects designed to improve base system reliability and allow for additional long-term contracted transportation services to a point of delivery on the Northern Border pipeline at Ventura, Iowa. The project is expected to be placed in service in 2025.

ANR Pipeline - Heartland Project

In February 2024, we approved the Heartland project, an expansion project on our ANR system that is expected to increase capacity and improve system reliability. The Heartland project involves pipeline looping, compressor facility additions as well as upgrades and is expected to increase ANR's overall market share in the Midwest region. The anticipated in-service date is late 2027.

ANR Section 4 Rate Case

ANR reached a settlement with its customers effective August 2022 and received FERC approval in April 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 second quarter 2023, previously accrued rate refund liabilities, including interest, were refunded to customers.

Gas Transmission Northwest LLC (GTN) - GTN XPress

In October 2023, FERC approved a set of reliability and expansion projects on the GTN System to support the existing system and provide for the transport of additional volumes enabled by the NGTL System's West Path Delivery Program. The projects are expected to be placed in service in 2024.

Great Lakes Rate Settlement

In April 2022, FERC approved Great Lakes' unopposed rate case settlement with its customers by which Great Lakes and the settling parties agreed to maintain existing recourse rates through October 31, 2025.

GTN Rate Case Settlement

In November 2021, FERC approved an uncontested rate settlement which set new recourse rates for GTN effective January 1, 2022 and instituted a rate moratorium through December 31, 2023. GTN must file for new rates no later than April 1, 2024.

Gillis Access Project

In November 2022, we sanctioned the development of the Gillis Access project, a 1.5 Bcf/d greenfield pipeline system to connect supplies from the Haynesville basin at Gillis to markets elsewhere in Louisiana. The 68 km (42 mile) Louisiana header system will also enable the rapidly growing Louisiana LNG export market to access Haynesville-sourced gas production as well as create a platform for further growth into the southeast Louisiana markets. The project is expected to be placed in service in 2024. In February 2023, we approved a 63 km (39 mile), 1.4 Bcf/d extension of the Gillis Access project to further connect supplies from the Haynesville basin at Gillis. Subject to customer final investment decision (FID), the project is expected to be placed in service in 2025.

OTHER U.S. NATURAL GAS PIPELINES

North Baja - North Baja XPress Project

In June 2023, the North Baja XPress project, an expansion project designed to expand capacity and meet increased customer demand on our North Baja pipeline, was placed in service.

TC PipeLines, LP

In March 2021, we completed the acquisition of all of the outstanding common units of TCLP not beneficially owned by TC Energy. TCLP common unitholders received 0.70 of a TC Energy common share for each TCLP common unit, resulting in the issuance of 38 million TC Energy common shares valued at approximately $2.1 billion, net of transaction costs.

Bison XPress Project

In third quarter 2023, we approved the Bison XPress project, an expansion project on our Northern Border and Bison systems that will replace and upgrade certain facilities and provide much needed production egress from the Bakken basin to a delivery point at the Cheyenne Hub. The project has an anticipated in-service date in 2026.

GTN XPress Project

In October 2023, FERC provided a certificate order approving our GTN XPress project, an expansion project on the GTN system that will provide for the transport of incremental contracted export capacity facilitated by the NGTL System/Foothills West Path Delivery Program. The project has an anticipated in-service date in 2024.

Virginia Reliability and Wisconsin Reliability Projects

In November and December 2023, the FERC provided a certificate order approving our Virginia Reliability (VR) and Wisconsin Reliability (WR) projects, respectively. The VR project will provide incremental capacity from Greensville County, Virginia to delivery points in Norfolk, Virginia. The WR project will provide mainline capacity to multiple points of delivery on our ANR System in Wisconsin. Each project has an anticipated in-service date in late 2025.

Developments in the Mexico Natural Gas Pipelines Segment

MEXICO NATURAL GAS PIPELINES

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 with an expected in-service by mid-2025 and an estimated project cost of US$4.5 billion.

We placed the lateral section of the Villa de Reyes pipeline into service in third quarter 2023. Construction of the south section of the Villa de Reyes pipeline is targeted for mechanical completion in the second half of 2024, subject to successful resolution of stakeholder issues. Additionally, we continue to evaluate the development and completion of the Tula pipeline with the CFE, which is subject to a future FID. Due to the delay of an FID, effective November 1, 2023, we have suspended recording AFUDC on the assets under construction for the Tula pipeline project.

The strategic alliance provides the CFE with the ability to hold an equity interest in TGNH, which is conditional upon the CFE contributing capital, acquiring land and supporting permitting on the TGNH projects, subject to regulatory approvals from COFECE and the CRE. Upon in-service of the Southeast Gateway pipeline and the completion of certain other contractual obligations, the CFE's equity interest in TGNH will equal approximately 15 per cent, and will increase to approximately 35 per cent upon expiry of the contract in 2055. In December 2023, TGNH and the CFE obtained from COFECE, a favourable merger ruling with and a determination that the proposed minority CFE equity participation in TGNH did not require a favourable cross participation opinion given that the CFE would not have a controlling interest in TGNH. TGNH and the CFE subsequently requested the CRE to confirm that a cross participation permit is not required given that the CFE would not have a controlling interest in TGNH. TGNH anticipates receiving CRE's approval in early 2024.

Tula

We placed the east section of the Tula pipeline into commercial service in third quarter 2022. In third quarter 2022, we reached an agreement with the CFE to jointly develop and complete the central segment of the Tula pipeline, which remains subject to an FID. We continue to work with the CFE on the Tula pipeline's west section to procure necessary land access and resolve legal claims.

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. Construction of the south section of the Villa de Reyes pipeline is targeted for mechanical completion in the second half of 2024, subject to successful resolution of stakeholder issues.

LIQUIDS PIPELINES

Developments in the Liquids Pipelines Segment

Keystone Pipeline System

In 2019 and 2020, three Keystone customers initiated complaints before the FERC and the CER regarding certain costs within the variable toll calculation. In December 2022, the CER issued a decision which resulted in a one-time adjustment related to previously charged tolls of $38 million. The CER has established a proceeding to consider Keystone's compliance filing required by the decision regarding the allocation of Drag Reducing Agent in the variable-toll. In February 2023, the FERC released its initial decision in respect of the complaint. As a result, we have recorded a one-time pre-tax charge of $57 million reflective of previously charged tolls between 2018 and 2022. A final order from the commission of the FERC is expected in 2024.

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. We will maintain our commitment to long-term reclamation and environmental monitoring activities.

A CAO was issued by PHMSA in December 2022, and later amended in March 2023. The pipeline is operating subject to the Amended CAO (ACAO), which includes certain operating pressure restrictions. Under the ACAO, we expect to continue to fulfill our Keystone contract commitments.

A RCFA was conducted by an independent third party and was released on April 21, 2023. The RCFA revealed that a unique set of circumstances occurred at the rupture location, which likely originated during construction, with the primary cause of the rupture being a fatigue crack. A comprehensive remedial work plan is being implemented, including the RCFA's recommendations, to enhance pipeline integrity and safety performance of the system.

At December 31, 2022, we accrued an environmental remediation liability of $650 million, before expected insurance recoveries and not including potential fines and penalties, which was revised at June 30, 2023 to $794 million based on a review of costs and commitments incurred. At December 31, 2023, the remediation cost estimate remains unchanged. Appropriate insurance policies are in place and we believe that it remains probable that the majority of environmental remediation costs will be eligible for recovery under our existing insurance coverage. As of December 31, 2023, we have received $575 million from insurance proceeds related to the environmental remediation. The additional environmental remediation costs recognized in second quarter 2023 included $36 million that we estimate to be recoverable from our wholly-owned captive insurance subsidiary.

Keystone XL

Following the revocation of the 2019 Presidential Permit for the Keystone XL pipeline project in January 2021, and after a comprehensive review of options in consultation with our partner, the Government of Alberta, in June 2021, we terminated the Keystone XL pipeline project. We determined that the carrying amount of these assets was no longer fully recoverable and recognized an asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations related to termination activities, of $2.8 billion ($2.1 billion after tax) for the year ending December 31, 2021, a significant portion of which was shared with the Government of Alberta, thereby reducing the net financial impact to us. After the 2019 Presidential Permit was revoked, construction activities ceased except for certain activities required to clean up and reclaim worksites in adherence with our commitment to safety, the environment and our regulatory requirements. Right-of-way clean up and restoration is substantially complete while termination activities will continue through the first half of 2024. We will continue to coordinate with regulators, stakeholders, landowners and Indigenous groups to meet our environmental and regulatory commitments.

In November 2021, we filed a Request for Arbitration to formally initiate a legacy NAFTA claim seeking more than US$15 billion in economic damages resulting from the revocation of the 2019 Presidential Permit. In September 2022, the International Centre for Settlement of Investment Disputes formally constituted a tribunal to hear our Request for Arbitration. In April 2023, the tribunal suspended the proceeding, granting a request from the U.S. Department of State to decide the jurisdictional grounds of the case as a preliminary matter. A hearing on the jurisdictional matter is set to occur in the second quarter of 2024. In April 2023, the Government of Alberta filed its own request for arbitration, which will proceed separately from TC Energy's claim.

Northern Courier

In November 2021, we sold our remaining 15 per cent equity interest in Northern Courier for $35 million in proceeds.

Port Neches

In March 2021, we entered a joint venture with Motiva Enterprises (Motiva) to construct the US$152 million Port Neches Link Pipeline System to connect the Keystone Pipeline System to Motiva's Port Neches Terminal, which supplies 630,000 Bbl/d to their Port Arthur refinery. This common carrier pipeline system also includes facilities to tie in additional liquids terminals to the Keystone Pipeline System with other downstream infrastructure. In March 2023, the Port Neches Link Pipeline System was placed in service. In December 2023, Motiva exercised its option to increase its equity interest in the joint venture. As a result, and in exchange for approximately USD $25 million in proceeds, subject to the agreed upon post-closing adjustment, our ownership interest decreased from 95 per cent to 74.9 per cent.

Proposed Spinoff of Liquids Pipelines Business

On July 27, 2023, we announced plans to separate into two independent, investment-grade, publicly listed companies through the proposed spinoff of our Liquids Pipelines business into its own entity named South Bow Corporation. In addition to TC Energy shareholder and court approvals, the spinoff Transaction is subject to receipt of favourable tax rulings from Canadian and U.S. tax authorities, receipt of necessary regulatory approvals, and satisfaction of other customary closing conditions. We expect that the spinoff Transaction will be completed in the second half of 2024.

Under the spinoff Transaction, TC Energy shareholders will retain their current ownership in TC Energy's common shares and receive a pro-rata allocation of common shares in South Bow Corporation. The determination of the number of common shares in South Bow Corporation to be distributed to TC Energy shareholders will be determined prior to the closing of the spinoff Transaction, which is expected to be tax free to TC Energy's Canadian and U.S. shareholders.

POWER AND ENERGY SOLUTIONS

Developments in the Power and Energy Solutions Segment

CANADIAN POWER

Saddlebrook Solar

In October 2023, we completed construction of the 81 MW Saddlebrook Solar project near Aldersyde, Alberta and began commissioning activities, including supplying generation to the Alberta market. Full commercial operation was achieved on January 5, 2024. The project was partially supported with funding from Emissions Reduction Alberta and Lockheed Martin.

Renewable Energy Contracts and/or Investment Opportunities

In November 2023, a majority of the Sharp Hills Wind Farm achieved commercial operation resulting in the commencement of our 15-year Power Purchase Agreement for 100 per cent of the power produced and the rights to all environmental attributes from the facility. In second quarter 2023, we finalized contracts to sell 50 MW under our 24-by-7 carbon-free power offering in Alberta. Contract terms range from 15 to 20 years and are expected to commence in 2025.

Bruce Power

In 2021, as part of the planned inspections, testing, analysis and maintenance activities at Bruce Power during the Unit 6 MCR outage and the Unit 3 planned outage, higher than anticipated readings of hydrogen concentration in pressure tubes were detected. These readings were limited to a very small area of the respective pressure tubes and did not impact safety nor pressure tube integrity as concluded following an assessment of all of the Bruce Power units. In October 2021, Unit 3 returned to service after the Canadian Nuclear Safety Commission approved Bruce Power's restart request following extensive inspections which demonstrated that safety and pressure tube integrity continued to meet regulatory requirements. Following the event, Bruce Power began incorporating additional inspections as part of its normal surveillance programs to address the findings, while progressing further programs that demonstrate fitness for service at elevated hydrogen concentration levels. These inspections were added to the Unit 7 planned outage which returned to service in January 2022.

The Unit 6 MCR, which began in January 2020, was declared commercially operational in September 2023, ahead of schedule and on budget despite challenges from the COVID-19 pandemic.

In first quarter 2023, Unit 3 was removed from service and began its MCR construction, with an expected return to service in 2026.

The final cost and schedule estimate for the Unit 4 MCR program was submitted to the IESO in December 2023, and received IESO approval on February 8, 2024. The Unit 4 MCR is expected to commence in first quarter 2025 with an expected completion in 2028. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available for Bruce Power and the IESO.

In 2021, Bruce Power launched Project 2030 with the goal of achieving a site peak output of 7,000 MW by 2033 in support of climate change targets and future clean energy needs. Project 2030 will focus on continued asset optimization, innovation and leveraging new technology, which could include integration with storage and other forms of energy, to increase the site peak output at Bruce Power.

Bruce Power's contract price increased in April 2022, in accordance with contract terms, reflecting capital to be invested under the Unit 3 MCR program and the 2022 to 2027 Asset Management program plus normal annual inflation adjustments.

Ontario Pumped Storage Project (OPSP)

As part of our strategy to capture opportunities that capitalize on the transition to a less carbon-intensive energy mix, we continue to progress the development of the OPSP, an energy storage facility located near Meaford, Ontario that is designed to provide 1,000 MW of flexible, clean energy to Ontario's electricity system using a process known as pumped hydro storage. In July 2021, the Federal Minister of National Defence granted long-term land access to the fourth Canadian Division Training Centre for development of the project on this site. In November 2021, Ontario's Minister of Energy instructed the IESO to progress the project to Gate 2 of the Unsolicited Proposals Process. Once in service, this project is designed to store emission-free energy when available and provide that energy to Ontario during periods of peak demand, thereby maximizing the value of existing emissions-free generation in the province. We also continue to consult with the Saugeen Ojibway Nation and other Indigenous groups along with other local stakeholders as we continue to advance this project, which remains subject to a number of conditions and approvals, including approval of our Board of Directors. A final decision to fund development costs of OPSP is subject to Cabinet approvals and the issuance of a Ministerial directive to the IESO.

U.S. POWER

In 2021, we announced that we were seeking to identify potential contracts and/or investment opportunities in up to 620 MW of wind energy projects, 300 MW of solar projects and 100 MW of energy storage projects. We also identified meaningful origination opportunities to supply renewable energy products and services to industrial and oil and gas sectors proximate to our in-corridor demand. In March 2023, we acquired 100 per cent of the Class B Membership interests in the 155 MW Fluvanna Wind Farm located in Scurry County, Texas for US$99 million, before post-closing adjustments. In June 2023, we acquired 100 per cent of the Class B Membership Interests in the 148 MW Blue Cloud Wind Farm located in Bailey County, Texas for US$125 million, before post-closing adjustments. As of December 31, 2023, we contracted approximately 400 MW from wind projects.

OTHER ENERGY SOLUTIONS

Lynchburg Renewable Fuels

In October 2022, we acquired a 30 per cent ownership interest in the Lynchburg Renewable Fuels project, a renewable natural gas (RNG) production facility in Lynchburg, Tennessee being developed by 3 Rivers Energy Partners, LLC (3 Rivers Energy). Along with our ownership interest, we will market all RNG and environmental attributes generated from the facility once operational, which we expect in 2024. We also have the option to jointly develop future RNG projects with 3 Rivers Energy.

Hydrogen Hubs

In 2021, we entered into individual Joint Development Agreements (JDAs) with Nikola Corporation (Nikola) and Hyzon Motors Inc. (Hyzon) to support customer-driven hydrogen production for long-haul transportation, power generation, large industrials and heating customers across the U.S. and Canada. As part of our JDA with Nikola, in April 2022, we announced a plan to evaluate a hydrogen production hub on 140 acres in Crossfield, Alberta, where we currently operate a natural gas storage facility. Our significant pipeline, storage and power assets can potentially be leveraged to lower the cost and increase the speed of development of these hubs. This may include exploring the integration of pipeline assets to enable hydrogen distribution and storage via pipeline and/or to deliver carbon dioxide to permanent sequestration sites to decarbonize the hydrogen production process. We are advancing multiple other hydrogen production opportunities to potentially serve long-haul transportation, power generation, large industrials and heating customers across the U.S. and Canada. We expect that measured investment in emerging technologies like hydrogen will help us expand our capabilities through energy transition, focusing on opportunities that complement our core business and where we can obtain favourable and strategically-consistent commercial arrangements such as rate regulation and/or long-term contracts.

Other Carbon Capture

We are collaborating with Minnkota Power Cooperative (Minnkota), Mitsubishi Heavy Industries and Kiewit on Project Tundra, a next-generation technology carbon capture and storage project. Project Tundra will be our first carbon capture and sequestration project in the U.S., designed to capture up to approximately 4 million tons of CO_2 per annum from Minnkota's Milton R. Young Generating Station. When constructed, Project Tundra is expected to be the largest post-combustion carbon capture project in North America and will support the continuation of baseload, reliable, power generation in the region. In December 2023, the U.S. Department of Energy and Office for Clean Energy Demonstrations announced up to US$350 million in funding for Project Tundra.

General

EMPLOYEES

At Year End, TC Energy's principal operating subsidiary, TCPL, had 7,415 employees, substantially all of whom were employed in Canada and the U.S., as set forth in the following table.

Calgary	2,635
Western Canada (excluding Calgary)	652
Eastern Canada	275
Houston	837
U.S. Midwest	822
U.S. Northeast	239
U.S. Southeast/Gulf Coast (excluding Houston)	1,161
U.S. West Coast	84
Mexico	710
Total	**7,415**

HEALTH, SAFETY, SUSTAINABILITY AND ENVIRONMENTAL PROTECTION AND SOCIAL POLICIES

A discussion of our health, safety, sustainability and environmental protection policies can be found in the MD&A in the *Other information – Health, safety, sustainability and environment* section, which section is incorporated by reference herein.

Social Policies

We have a number of corporate governance documents including a Commitment Statement, policies and standards to help guide our teams' behavior and actions, so they understand their responsibility and extend respect, courtesy and the opportunity to respond to Indigenous groups and stakeholders. We have a Code of Business Ethics (COBE) Policy which applies to all employees, officers and directors, and contingent workforce contractors of TC Energy and its wholly-owned subsidiaries and operated entities in countries where we conduct business, with the exception of independently operated entities whose corporate governance documents meet or exceed TC Energy's requirements. Annual online COBE training is provided to all employees and contingent workforce contractors, and all employees and contingent workforce contractors (including executive officers) and directors must certify their compliance with COBE annually.

We also have an Avoiding Bribery and Corruption Program which includes an Avoiding Bribery and Corruption Policy, annual online training included as part of annual online COBE training, instructor-led training provided to personnel in higher risk areas of our business, a supplier and contractor due diligence review process, and auditing of certain types of transactions. Our approach to Indigenous and stakeholder engagement is based on building and sustaining support through early and honest communication, mitigating impacts, and mutually beneficial partnerships. Our Commitment Statement provides the structure to guide our teams' behavior and actions, so they understand their responsibility and the opportunity to empower Indigenous groups and stakeholders through partnerships and enhanced relationships.

Our Indigenous Relations Policy is informed by our guiding principles and corporate values to ensure we build and sustain support through early and honest communication, by mitigating impacts, and through mutually beneficial partnerships. We seek to listen to Indigenous peoples and incorporate their traditional and local knowledge in project design and planning. We strive to work with Indigenous communities to mitigate negative impacts and maximize benefits through hiring and buying locally. We aim to build mutually beneficial, partnership-oriented relationships with Indigenous communities where benefits significantly outweigh the impacts, and our legacy is positive for those most impacted by our activities. In Canada, we will seek to expand benefits for equity participation in our projects and assets because the best way to align interests is to sit at the table together as partners/owners. Through all these efforts, we strive to be considered as a partner of choice for Indigenous groups and play a meaningful role in reconciliation.

We work to understand and mitigate the complexity of sustainability matters, and their interconnectivity as they relate to our business. These matters are of great importance to Indigenous groups and stakeholders and have an impact on our ability to build and operate energy infrastructure.

Consistent with our Commitment Statement and our five core values of safety, innovation, responsibility, collaboration and integrity, TC Energy does not tolerate human rights abuses. In our business activities, including engaging with Indigenous groups and stakeholders across Canada, the U.S and Mexico, we support access to basic human rights such as rights to fresh water and will not be complicit with or engage in any activity that solicits or encourages abuse of human rights such as forced labour, child labour, or physical or mental abuses.

Risk factors

A discussion of our risk factors can be found in the MD&A in the*Natural Gas Pipelines Business, Natural Gas Pipelines - Business risks, Liquids Pipelines – Business risks, Power and Energy Solutions – Business risks* and *Other information – Risk oversight and enterprise risk management*sections, which sections are incorporated by reference herein.

Dividends

Our Board has not adopted a formal dividend policy The Board reviews the financial performance of TC Energy quarterly and makes a determination of the appropriate level of dividends to be declared in the following quarter. Currently, our payment of dividends is primarily funded from dividends TC Energy receives as the sole common shareholder of TCPL.

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.

Additionally, pursuant to the terms of the trust notes issued by TransCanada Trust (a financing trust subsidiary wholly-owned by TCPL) and related agreements, in certain circumstances, including where holders of the trust notes receive deferral preferred shares of TCPL in lieu of cash interest payments and where exchange preferred shares of TCPL are issued to holders of the trust notes as a result of certain bankruptcy related events, 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 such exchange or deferral preferred shares are redeemed by TCPL. No deferral preferred shares or exchange preferred shares of TCPL have ever been issued.

Dividends on our preferred shares are payable quarterly, as and when declared by the Board. The dividends declared on our common and preferred shares during the past three completed financial years, and the increase to the quarterly dividend per common share on our outstanding common shares for the quarter ending March 31, 2024, are set out in the MD&A under the heading *About our business – 2023 Financial highlights – Dividends*section, which section is incorporated by reference herein.

Description of capital structure

SHARE CAPITAL

TC Energy's authorized share capital consists of an unlimited number of common shares and an unlimited number of first preferred shares and second preferred shares, issuable in series. The number of common shares and preferred shares issued and outstanding as at Year End are set out in the MD&A in the *Financial Condition – Share information* section, which section is incorporated by reference herein. The following is a description of the material characteristics of each of these classes of shares.

Common shares

The common shares entitle the holders thereof to one vote per share at all meetings of shareholders, except meetings at which only holders of another specified class of shares are entitled to vote, and, subject to the rights, privileges, restrictions and conditions attaching to the first preferred shares and the second preferred shares, whether as a class or a series, and to any other class or series of shares of TC Energy which rank prior to the common shares, entitle the holders thereof to receive (i) dividends if, as and when declared by the Board out of the assets of TC Energy properly applicable to the payment of the dividends in such amount and payable at such times and at such place or places as the Board may from time to time determine, and (ii) the remaining property of TC Energy upon a liquidation, dissolution or winding up of the Company.

We have a shareholder rights plan (the Plan) that is designed to protect the rights of our shareholders, ensure they are treated fairly and provide the Board with adequate time to identify, develop and negotiate alternative value maximizing transactions if there is a take-over bid for TC Energy. The Plan creates a right attaching to each common share outstanding and to each common share subsequently issued. Each right becomes exercisable 10 trading days after a person has acquired (an acquiring person), or commences a take-over bid to acquire, 20 per cent or more of the common shares, other than by an acquisition pursuant to a take-over bid permitted under the terms of the Plan (a permitted bid). Prior to a flip-in event (as described below), each right permits registered holders to purchase from the Company common shares of TC Energy at an exercise price equal to three times the market price of such shares, subject to adjustments and anti-dilution provisions (the exercise price). The beneficial acquisition by any person of 20 per cent or more of the common shares, other than by way of a permitted bid, is referred to as a flip-in event. Ten trading days after a flip-in event, each right will permit registered holders other than an acquiring person to receive, upon payment of the exercise price, the number of common shares with an aggregate market price equal to twice the exercise price. The Plan was reconfirmed at the 2022 annual meeting of TC Energy shareholders and must be reconfirmed at every third annual meeting thereafter. Reconfirmation of the Plan will be voted on at the 2025 annual meeting of TC Energy shareholders.

A discussion of our dividend reinvestment and share purchase plan can be found in the MD&A in the *About our business - 2023 Financial highlights – Dividends – Dividend reinvestment and share purchase plan* and the *Financial condition - Dividend reinvestment plan* sections of the MD&A, which sections are incorporated by reference herein.

First preferred shares

Subject to certain limitations, the Board may, from time to time, issue first preferred shares in one or more series and determine for any such series, its designation, number of shares and respective rights, privileges, restrictions and conditions. The first preferred shares as a class have, among others, the provisions described below.

The first preferred shares of each series rank on a parity with the first preferred shares of every other series, and are entitled to preference over the common shares, the second preferred shares and any other shares ranking junior to the first preferred shares with respect to the payment of dividends, the repayment of capital and the distribution of assets of TC Energy in the event of its liquidation, dissolution or winding up.

Except as provided by the CBCA, the holders of the first preferred shares will not have any voting rights nor will they be entitled to receive notice of or to attend shareholders' meetings. The holders of any particular series of first preferred shares will, if the directors so determine prior to the issuance of such series, be entitled to such voting rights as may be determined by the Board if TC Energy fails to pay dividends on that series of preferred shares for any period as may be so determined by the Board. TC Energy currently does not intend to issue any first preferred shares with voting rights, and any issuances of first preferred shares are expected to be made only in connection with corporate financings.

The provisions attaching to the first preferred shares as a class may be modified, amended or varied only with the approval of the holders of the first preferred shares as a class. Any such approval to be given by the holders of the first preferred shares may be given by the affirmative vote of the holders of not less than 66 $^{2/3}$ per cent of the first preferred shares represented and voted at a meeting or adjourned meeting of such holders.

The holders of Series 1, 3, 5, 7, 9 and 11 preferred shares will be entitled to receive quarterly fixed rate cumulative preferential cash dividends, as and when declared by the Board, to be reset periodically on prescribed dates to an annualized rate equal to the sum of the then five-year Government of Canada bond yield, calculated at the start of the applicable five-year period, and a spread as set forth in the table below and have the right to convert their shares into cumulative redeemable Series 2, 4, 6, 8, 10 and 12 preferred shares, respectively, subject to certain conditions, on such conversion dates as set forth in the table below. The Series 1, 3, 5, 7, 9 and 11 preferred shares are redeemable by TC Energy in whole or in part on such redemption dates as set forth in the table below, by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon.

The holders of Series 2, 4, 6, 8, 10 and 12 preferred shares will be entitled to receive quarterly floating rate cumulative preferential cash dividends, as and when declared by the Board, at an annualized rate equal to the sum of the then 90-day Government of Canada treasury bill rate, recalculated quarterly, and a spread as set forth in the table below and have the right to convert their shares into Series 1, 3, 5, 7, 9 and 11 preferred shares, respectively, subject to certain conditions, on such conversion dates as set forth in the table below. The Series 2, 4, 6, 8, 10 and 12 preferred shares are redeemable by TC Energy in whole or in part after their respective initial redemption date as set forth in the table below, by the payment of an amount in cash for each share to be redeemed equal to (i) $25.00 in the case of redemptions on such redemption dates as set out in the table below, or (ii) $25.50 in the case of redemptions on any other date, in each case plus all accrued and unpaid dividends thereon.

In the event of liquidation, dissolution or winding up of TC Energy, the holders of Series 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11 and 12 preferred shares shall be entitled to receive $25.00 per preferred share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the first preferred shares.

Series of first preferred shares	Initial redemption/conversion date	Redemption/conversion dates	Spread (%)
Series 1 preferred shares	December 31, 2014	December 31, 2024 and every fifth year thereafter	1.92
Series 2 preferred shares	—	December 31, 2024 and every fifth year thereafter	1.92
Series 3 preferred shares	June 30, 2015	June 30, 2025 and every fifth year thereafter	1.28
Series 4 preferred shares	—	June 30, 2025 and every fifth year thereafter	1.28
Series 5 preferred shares	January 30, 2016	January 30, 2026 and every fifth year thereafter	1.54
Series 6 preferred shares	—	January 30, 2026 and every fifth year thereafter	1.54
Series 7 preferred shares	April 30, 2019	April 30, 2024 and every fifth year thereafter	2.38
Series 8 preferred shares	—	April 30, 2024 and every fifth year thereafter	2.38
Series 9 preferred shares	October 30, 2019	October 30, 2024 and every fifth year thereafter	2.35
Series 10 preferred shares	—	October 30, 2024 and every fifth year thereafter	2.35
Series 11 preferred shares	November 30, 2020	November 28, 2025 and every fifth year thereafter	2.96
Series 12 preferred shares	—	November 28, 2025 and every fifth year thereafter	2.96

Except as provided by the CBCA, the respective holders of the first preferred shares of each outstanding series are not entitled to receive notice of, attend at, nor vote at any meeting of shareholders unless and until TC Energy shall have failed to pay eight quarterly dividends on such series of preferred shares, whether or not consecutive, in which case the holders of the first preferred shares of such series shall have the right to receive notice of and to attend each meeting of shareholders at which directors are to be elected and which take place more than 60 days after the date on which the failure first occurs, and to one vote with respect to resolutions to elect directors for each of the first preferred share of such series, until all arrears of dividends have been paid. Subject to the CBCA, the series provisions attaching to the first preferred shares may be amended with the written approval of all the holders of such series of shares outstanding or by at least two thirds of the votes cast at a meeting of the holders of such shares duly called for that purpose and at which a quorum is present.

Second preferred shares

The rights, privileges, restrictions and conditions attaching to the second preferred shares are substantially identical to those attaching to the first preferred shares, except that the second preferred shares rank junior to the first preferred shares with respect to the payment of dividends, repayment of capital and the distribution of assets of TC Energy in the event of a liquidation, dissolution or winding up of TC Energy.

Credit ratings

Although TC Energy has not issued debt to the public, it has been assigned credit ratings by Moody's Investors Service, Inc. (Moody's), S&P Global Ratings (S&P) and Fitch Ratings Inc. (Fitch), and its outstanding preferred shares have also been assigned credit ratings by S&P, Fitch and DBRS Limited (DBRS). Moody's has assigned TC Energy an issuer rating of Baa3 with a stable outlook, S&P has assigned an issuer credit rating of BBB+ with a negative outlook, and Fitch has assigned a long-term issuer default rating of BBB+ with a stable outlook. TC Energy does not presently intend to issue debt securities to the public in its own name and any future debt financing requirements are expected to continue to be funded primarily through its subsidiary, TCPL, and TransCanada Trust, a wholly-owned financing trust subsidiary of TCPL. The following table sets out the current credit ratings assigned to those outstanding classes of securities of the Company, TCPL and TransCanada Trust and certain related subsidiaries which have been rated by Moody's, S&P, Fitch and DBRS:

	Moody's	S&P	Fitch	DBRS
TCPL - Senior unsecured debt	Baa2	BBB+	BBB+	BBB (high)
TCPL - Junior subordinated notes	Baa3	BBB-	Not rated	BBB (low)
TransCanada Trust - Subordinated trust notes	Ba1	BBB-	BBB-	Not rated
TC Energy Corporation - Preferred shares	Not rated	P-2 (Low)	BBB-	Pfd-3 (high)
Commercial paper (TCPL and TCPL guaranteed)	P-2	A-2	F2	R-2 (high)
Rating outlook/status	Stable	Negative	Stable	Stable

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. Credit ratings are not recommendations to purchase, hold or sell securities and do not address the market price or suitability of a specific security for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

Each of the Company, TCPL, TransCanada Trust and certain of our other subsidiaries paid fees to each of Moody's, S&P, Fitch and DBRS for the credit ratings rendered in respect of their outstanding classes of securities noted above. In addition to annual monitoring fees for the Company and TCPL and their rated securities, additional payments are made in respect of other services provided in connection with various rating advisory services.

The information concerning our credit ratings relates to our financing costs, liquidity and operations. The availability and cost of our funding options may be affected by certain factors, including the global capital markets environment and outlook as well as our financial performance. Our access to capital markets for required capital at competitive rates is influenced by our credit rating and rating outlook, as determined by credit rating agencies such as Moody's, S&P, Fitch and DBRS. If our ratings were downgraded, TC Energy's financing costs and future debt issuances could be unfavourably impacted. A description of the rating agencies' credit ratings listed in the table above is set out below.

MOODY'S

Moody's has different rating scales for short- and long-term obligations. Numerical modifiers 1, 2 and 3 are appended to each rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and a modifier 3 indicates a ranking in the lower end of that generic rating category. The Baa2 rating assigned to TCPL's senior unsecured debt and the Baa3 rating assigned to TCPL's junior subordinated notes are in the fourth highest of nine rating categories for long-term obligations. Obligations rated Baa are judged to be medium-grade and are subject to moderate credit risk, and as such, may possess certain speculative characteristics. The Ba1 rating assigned to the TransCanada Trust subordinated trust notes, is in the fifth highest of nine rating categories for long-term obligations. Obligations rated Ba are judged to have speculative elements and are subject to substantial credit risk. The P-2 rating assigned to TCPL's and TCPL guaranteed U.S. commercial paper programs is the second highest of four rating categories for short-term debt issuers. Issuers rated P-2 have a strong ability to repay short-term debt obligations. Outlooks may be assigned at the issuer level or at the rating level. A Moody's rating outlook is an opinion regarding the likely rating direction over the medium term. A stable outlook indicates a low likelihood of a rating change over the medium term. A negative, positive or developing outlook indicates a higher likelihood of a rating change over the medium term.

S&P

S&P has different rating scales for short- and long-term obligations and Canadian preferred shares. Ratings from AA through CCC may be modified by the addition of a plus (+) or minus (-) sign to show the relative standing within a particular rating category. The BBB+ rating assigned to TCPL's senior unsecured debt is in the fourth highest of 10 rating categories for long-term obligations. A BBB rating indicates the obligor's capacity to meet its financial commitment is adequate; however, the obligation is more subject to the adverse effects of changes in circumstances and economic conditions than obligations in higher rated categories. The BBB- rating assigned to TCPL's junior subordinated notes and to the TransCanada Trust subordinated trust notes, is in the fourth highest of 10 rating categories for long-term debt obligations and the P-2 (Low) rating assigned to TC Energy's preferred shares is the second highest of eight rating categories for Canadian preferred shares. The BBB- and P-2 (Low) ratings assigned to TCPL's junior subordinated notes, the TransCanada Trust subordinated trust notes and TC Energy's preferred shares indicate these obligations exhibit adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. TCPL's and TCPL guaranteed U.S. commercial paper programs are each rated A-2 which is the second highest of six rating categories for short-term debt issuers. Short-term debt issuers rated A-2 have satisfactory capacity to meet their financial commitments, however they are somewhat more susceptible to adverse effects of changes in circumstances and economic conditions than obligors in the highest rating category. S&P assigns outlooks to issuers and not to individual debt securities. An S&P outlook assesses the potential direction of a long-term credit rating over the intermediate term, which is generally up to two years for investment grade issuers. S&P has assigned a negative outlook to the Company, meaning that a rating may be lowered by S&P.

FITCH

Fitch has different rating scales for short- and long-term obligations. Ratings from AA through CCC may be modified by the addition of a plus (+) or minus (-) sign to show the relative standing within a particular rating category. The BBB+ rating assigned to TCPL's senior unsecured debt, and the BBB- ratings assigned to the TransCanada Trust subordinated trust notes and TC Energy's preferred shares are in the fourth highest of 11 rating categories for long-term obligations. A BBB rating indicates that expectations of default risk are currently low and that the capacity for payment of financial commitments is considered adequate, but adverse business or economic conditions are more likely to impair this capacity. The F2 rating assigned to TCPL's and TCPL guaranteed U.S. commercial paper program is the second highest of seven rating categories for short-term debt issuers. Issuers rated F2 have good intrinsic capacity for timely payment of financial commitments. Ratings outlooks by Fitch indicate the direction a rating is likely to move over a one-to-two year period and reflect financial or other trends that have not yet reached or been sustained to the level that would cause a rating action, but which may do so if such trends continue.

DBRS

DBRS has different rating scales for short- and long-term obligations and Canadian preferred shares. High or low grades are used to indicate the relative standing within all rating categories other than AAA and D and other than in respect of DBRS' ratings of commercial paper and short-term debt, which utilize high, middle and low subcategories for its R-1 and R-2 rating categories. In respect of long-term debt and preferred share ratings, the absence of either a high or low designation indicates the rating is in the middle of the category. The BBB (high) rating assigned to TCPL's senior unsecured debt and the BBB (low) rating assigned to TCPL's junior subordinated notes are in the fourth highest of 10 categories for long-term debt and indicate adequate credit quality. The capacity for the payment of financial obligations is considered acceptable. Long-term debt rated BBB may be vulnerable to future events. The Pfd-3 (high) rating assigned to TC Energy's preferred shares is in the third highest of six rating categories for preferred shares. Preferred shares rated Pfd-3 are generally of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present which detract from debt protection. Pfd-3 ratings generally correspond with issuers with a BBB category or higher reference point. The R-2 (high) rating assigned to TCPL's Canadian commercial paper program is in the fourth highest of 10 rating categories for short-term debt issuers and indicates the upper end of adequate credit quality. The capacity for payment of short-term financial obligations as they fall due is acceptable. Short-term debt rated R-2 (high) may be vulnerable to future events. Rating trends provide guidance in respect of DBRS' opinion regarding the outlook for a credit rating. The rating trend indicates the direction in which DBRS considers the credit rating may move if present circumstances continue. In cases when a significant event occurs that directly impacts the credit quality of a particular entity or group of entities and there is uncertainty regarding the outcome, and DBRS is unable to provide an objective, forward-looking opinion in a timely fashion, then the credit ratings of the issuer are typically placed “Under Review” with the appropriate Implications designation of Positive, Negative or Developing.

Market for securities

TC Energy's common shares are listed on the TSX and the NYSE under the symbol TRP. The following table sets out our preferred shares listed on the TSX.

Type	Issue Date	Stock Symbol
Series 1 preferred shares	September 30, 2009	TRP.PR.A
Series 2 preferred shares	December 31, 2014	TRP.PR.F
Series 3 preferred shares	March 11, 2010	TRP.PR.B
Series 4 preferred shares	June 30, 2015	TRP.PR.H
Series 5 preferred shares	June 29, 2010	TRP.PR.C
Series 6 preferred shares	February 1, 2016	TRP.PR.I
Series 7 preferred shares	March 4, 2013	TRP.PR.D
Series 9 preferred shares	January 20, 2014	TRP.PR.E
Series 11 preferred shares	March 2, 2015	TRP.PR.G

The following tables set out the reported monthly high, low, and month end closing trading prices and monthly trading volumes of the common shares of TC Energy on the TSX and the NYSE, and the respective Series 1, 2, 3, 4, 5, 6, 7, 9 and 11 preferred shares on the TSX, for the periods indicated:

COMMON SHARES

	TSX (TRP)				NYSE (TRP)			
Month	High ($)	Low ($)	Close ($)	Volume traded	High (US$)	Low (US$)	Close (US$)	Volume traded
December 2023	$53.64	$50.44	$51.76	171,647,731	$40.63	$37.33	$39.09	57,222,628
November 2023	$51.11	$47.69	$50.89	72,082,915	$37.63	$34.34	$37.52	44,668,072
October 2023	$48.54	$44.70	$47.76	161,361,514	$35.61	$32.52	$34.45	77,713,858
September 2023	$50.92	$46.63	$46.71	210,418,660	$37.75	$34.36	$34.41	73,567,707
August 2023	$49.55	$46.60	$48.80	84,303,835	$36.94	$34.83	$36.12	48,553,727
July 2023	$53.70	$43.70	$47.26	159,797,173	$40.96	$33.02	$35.87	69,369,694
June 2023	$55.91	$51.79	$53.54	146,459,419	$41.85	$38.96	$40.41	51,418,849
May 2023	$56.90	$52.39	$52.84	52,557,565	$42.49	$38.54	$38.94	31,003,066
April 2023	$57.02	$52.60	$56.31	150,275,964	$42.76	$39.11	$41.54	33,927,489
March 2023	$56.69	$50.70	$52.57	214,463,103	$41.66	$36.79	$38.91	46,776,020
February 2023	$57.47	$52.93	$54.31	68,514,285	$42.80	$39.66	$39.81	45,500,393
January 2023	$58.56	$52.12	$57.33	111,893,097	$45.18	$38.35	$43.14	32,100,943

PREFERRED SHARES

Month	Series 1	Series 2	Series 3	Series 4	Series 5	Series 6	Series 7	Series 9	Series 11
December 2023									
High	$14.22	$14.97	$11.38	$13.19	$11.70	$14.35	$16.75	$15.49	$16.32
Low	$13.15	$13.99	$10.60	$12.59	$10.90	$13.46	$15.76	$14.56	$15.28
Close	$13.91	$14.69	$11.28	$12.91	$11.45	$13.70	$16.44	$15.09	$16.32
Volume Traded	254,326	93,158	162,316	37,717	249,815	61,753	244,722	351,642	109,614
November 2023									
High	$14.17	$15.02	$11.40	$13.50	$11.56	$14.00	$16.83	$15.58	$15.90
Low	$13.12	$13.98	$9.97	$12.29	$9.99	$13.16	$15.40	$14.50	$14.38
Close	$14.14	$14.74	$11.15	$13.19	$11.56	$13.90	$16.55	$15.35	$15.51
Volume Traded	234,263	103,264	200,638	76,948	176,311	56,413	510,039	267,361	129,801
October 2023									
High	$13.39	$14.53	$10.27	$12.70	$10.37	$13.70	$15.85	$14.62	$14.89
Low	12.62	$13.90	$9.86	$12.15	$9.91	$13.05	$14.94	$13.75	$14.21
Close	$13.20	$13.90	$9.97	$12.24	$10.19	$13.05	$15.25	$14.55	$14.69
Volume Traded	206,953	51,516	101,740	44,649	286,250	29,186	397,558	576,126	269,971
September 2023									
High	$13.37	$14.55	$10.45	$12.80	$10.55	$14.08	$16.04	$14.55	$15.20
Low	$12.70	$13.80	$9.58	$12.11	$10.06	$13.04	$14.58	$13.82	$14.61
Close	$13.21	$14.22	$10.20	$12.40	$10.28	$13.25	$15.58	$14.46	$14.96
Volume Traded	175,870	55,154	73,799	50,225	162,861	29,018	405,098	315,318	129,734
August 2023									
High	$13.97	$14.85	$10.70	$13.41	$11.51	$14.70	$15.30	$14.75	$15.92
Low	$12.66	$14.00	$9.95	$12.50	$10.13	$13.60	$14.56	$13.70	$14.50
Close	$12.75	$14.01	$10.10	$12.50	$10.42	$13.60	$14.66	$14.00	$14.81
Volume Traded	321,010	98,860	123,959	146,532	170,324	18,761	538,755	384,943	196,817
July 2023									
High	$14.45	$14.95	$11.25	$13.34	$12.00	$14.10	$16.08	$15.21	$16.60
Low	$13.40	$14.60	$10.40	$12.90	$10.55	$13.56	$15.02	$14.46	$15.77
Close	$13.60	$14.73	$10.98	$13.20	$11.11	$13.84	$15.25	$14.66	$15.95
Volume Traded	286,303	90,724	245,190	202,386	369,773	19,145	380,506	195,021	196,096
June 2023									
High	$13.90	$14.74	$10.59	$13.01	$11.00	$14.97	$15.79	$15.52	$16.74
Low	$12.90	$14.31	$10.06	$12.70	$10.40	$13.58	$14.64	$14.33	$15.47
Close	$13.67	$14.50	$10.43	$12.95	$10.74	$13.87	$15.29	$14.75	$16.30
Volume Traded	160,708	141,497	129,735	98,335	142,437	99,520	647,724	474,284	54,949
May 2023									
High	$14.04	$15.21	$10.76	$13.78	$11.70	$14.97	$15.77	$15.19	$17.10
Low	$12.73	$14.25	$9.83	$12.76	$10.20	$14.00	$14.25	$13.96	$15.19
Close	$13.06	$14.40	$10.12	$12.85	$10.70	$14.00	$14.68	$14.34	$15.63
Volume Traded	134,361	72,416	102,488	51,669	82,354	12,636	163,031	232,951	69,416
April 2023									
High	$14.24	$15.41	$11.00	$13.78	$11.78	$15.15	$16.00	$15.70	$17.12
Low	$13.58	$14.71	$10.53	$12.75	$11.09	$14.16	$15.30	$14.85	$16.40
Close	$13.91	$15.23	$10.71	$13.31	$11.56	$14.36	$15.57	$15.25	$16.75
Volume Traded	94,879	337,918	85,911	25,162	58,071	8,978	173,048	70,051	76,131
March 2023									
High	$14.60	$16.45	$11.90	$14.65	$12.15	$15.65	$16.59	$16.24	$17.73
Low	$13.20	$15.10	$10.23	$13.11	$10.80	$14.39	$15.18	$14.69	$16.42
Close	$13.60	$15.22	$10.70	$13.37	$11.26	$14.49	$15.47	$14.99	$16.60
Volume Traded	206,923	35,449	75,575	35,460	157,000	47,841	135,099	255,894	61,716
February 2023									
High	$14.90	$16.68	$12.17	$14.65	$12.36	$15.55	$16.65	$16.29	$18.07
Low	$14.46	$16.05	$11.54	$13.91	$11.97	$14.81	$16.06	$15.75	$17.10
Close	$14.59	$16.25	$11.62	$14.54	$12.12	$15.45	$16.46	$15.95	$17.55
Volume Traded	150,290	50,592	27,203	28,418	122,556	12,706	303,194	118,257	51,100
January 2023									
High	$15.11	$16.89	$12.30	$14.65	$13.85	$15.75	$16.75	$16.49	$18.29
Low	$13.61	$14.81	$10.77	$13.02	$11.35	$14.10	$15.34	$14.79	$16.05
Close	$14.48	$16.13	$11.76	$14.21	$12.12	$15.03	$16.35	$16.00	$17.57
Volume Traded	119,106	53,112	56,557	44,954	60,064	14,301	189,972	170,696	49,293

Directors and officers

As of February 15, 2024, the directors and executive officers of TC Energy as a group beneficially owned, or exercised control or direction over, directly or indirectly, an aggregate of 510,012 common shares, constituting 0.05 per cent of the common shares of TC Energy. The Company collects this information from our directors and executive officers but otherwise we have no direct knowledge of individual holdings of TC Energy's securities.

DIRECTORS

The following table sets forth the names of the directors who serve on the Board as of February 15, 2024, together with their jurisdictions of residence, all positions and offices held by them with TC Energy, unless otherwise stated, their principal occupations or employment during the past five years and the year from which each director has continually served as a director of TC Energy. Positions and offices held with TC Energy are also held by such person at TCPL. Each director holds office until the next annual meeting or until his or her successor is earlier elected or appointed.

Name and place of residence	Principal occupation during the five preceding years	Director since
Cheryl F. Campbell Monument, Colorado U.S.A.	Corporate director. Director, Pacific Gas & Electric Corporation (PGE) (utilities) since April 2019, Summit Utilities (natural gas distribution) since September 2020, JANA Corporation (JANA) (engineering) since January 2020. Director, National Underground Group (infrastructure service provider) from March 2018 to December 2023. Senior Vice-President, Gas, Xcel Energy, Inc. (Xcel) (utility supplier) from September 2004 to June 2018.	2022
Michael R. Culbert Calgary, Alberta Canada	Corporate director. Director, Humble Midstream II LLC (oil and gas) since December 2023 and Precision Drilling Corporation (Precision) (oil and gas services) since December 2017. Director, Reserve Royalty Income Trust (private oil and gas royalty trust) from May 2017 to June 2021. Director, Enerplus Corporation (Enerplus) (oil and gas, exploration and production) from March 2014 to August 2020. Vice-Chair (Non-Executive) and Director, PETRONAS Canada Ltd. (PETRONAS) (oil and natural gas) from November 2016 to March 2020.	2020
William D. Johnson Knoxville, Tennessee U.S.A.	Corporate director. Director, NiSource Inc. (utilities) since March 2022. President and CEO, PGE (utilities) from May 2019 to June 2020. President and CEO, Tennessee Valley Authority (Tennessee Valley) (electricity) from January 2013 to May 2019.	2021
Susan C. Jones Calgary, Alberta Canada	Corporate director. Director, Canadian National Railway Limited (freight railway) since May 2022. Director, Piedmont Lithium Inc. (Piedmont) (emerging lithium company) from June 2021 to June 2023. Director, ARC Resources Ltd. (ARC) (previously Seven Generations Energy Ltd.) (oil and gas, exploration and production) from May 2020 to February 2023. Director, Gibson Energy Inc. (Gibson) (mid-stream oil-focused infrastructure company) from December 2018 to February 2020. Director, Canpotex Limited (Canpotex) (Canadian exporter of potash) from June 2018 to December 2019 (Chair of the Board from June 2019 to December 2019). Executive Vice-President and CEO of the Potash Business Unit, Nutrien Ltd. (Nutrien) (largest global underground soft-rock miner) from June 2018 to September 2019. Executive Advisor to the CEO, Nutrien, from October 2019 to December 2019. Executive Vice-President and CEO, Potash Unit, Nutrien, from June 2018 to September 2019. Executive Vice-President and President, Phosphate Unit, Nutrien, from January 2018 to May 2018.	2020
John E. Lowe Houston, Texas U.S.A.	Corporate director. Chair of the Board, TC Energy since January 2024. Director, Phillips 66 Company (energy infrastructure) since May 2012. Non-executive Chair of the Board, Apache Corporation (Apache) (oil and gas) from May 2015 to September 2022. Senior Executive Adviser at Tudor, Pickering, Holt & Co. LLC (energy investment and merchant banking) from September 2012 to August 2021.	2015
David MacNaughton Toronto, Ontario Canada	President, Palantir Canada (data integration and analytics software) since September 2019. Canada's Ambassador to the United States from March 2016 to August 2019.	2020

Name and place of residence	Principal occupation during the five preceding years	Director since
François L. Poirier Calgary, Alberta Canada[1]	President and CEO since January 2021. Chief Operating Officer (COO) and President, Power and Storage from September 2020 to December 2020. COO and President, Power and Storage and Mexico from January 2020 to September 2020. Executive Vice-President, Corporate Development and Strategy, and President, Power & Storage and Mexico from May 2019 to January 2020. Executive Vice-President, Corporate Development and Strategy and President, Mexico Natural Gas Pipelines and Energy from January 2019 to May 2019. Executive Vice-President, Strategy and Corporate Development from February 2017 to December 2018.	2021
Una Power Vancouver, British Columbia Canada	Corporate director. Director, Teck Resources Limited (Teck) (diversified mining) since April 2017 and The Bank of Nova Scotia (Scotiabank) (chartered bank) since April 2016. Director, Kinross Gold Corporation (gold producer) from April 2013 to May 2019.	2019
Mary Pat Salomone Naples, Florida U.S.A.	Corporate director. Director, Intertape Polymer Group (manufacturing) from November 2015 to June 2022. Director, Herc Rentals (equipment rental) from July 2016 to December 2021.	2013
Indira Samarasekera Vancouver, British Columbia Canada	Senior Advisor, Bennett Jones LLP (law firm) since September 2015. Director, Intact Financial Corporation (property and casualty insurance) since May 2021, Stelco Holdings Inc. (manufacturing) since May 2018 and Magna International Inc. (automotive manufacturing) since May 2014. Member, selection panel for Canada's outstanding CEO since 2013. Director, Scotiabank (chartered bank) from May 2008 to April 2021.	2016
Siim A. Vanaselja Toronto, Ontario Canada	Corporate director. Chair of the Board, TC Energy from May 2017 to December 2023. Director, Power Corporation (financial services) since May 2020, Power Financial Corporation (financial services) since May 2018, RioCan Real Estate Investment Trust (real estate) since May 2017 and Great-West Lifeco Inc. (financial services) since May 2014.	2014
Thierry Vandal Mamaroneck, New York U.S.A.	President, Axium Infrastructure U.S., Inc. (Axium U.S.) (independent infrastructure fund management firm) and Director, Axium Infrastructure Inc. (Axium) (independent infrastructure fund management firm) since 2015. Director, Royal Bank of Canada (RBC) (chartered bank) since 2015.	2017
Dheeraj "D" Verma Houston, Texas U.S.A.	Senior Advisor, Quantum Energy Partners (Quantum) (private equity firm) since November 2021. President, Quantum Energy Partners from November 2016 to November 2021. Director, Jagged Peak Energy Inc. (oil and gas) from January 2017 to January 2020.	2022

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

As of the date hereof, except as indicated below, no other director or executive officer of the Company is or was a director or officer of another company in the past 10 years that:

- was the subject of a cease trade or similar order, or an order denying that company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days.
- was involved in an event that resulted in the company being subject to one of the above orders after the director or executive officer no longer held that role with the company, which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.
- while acting in that capacity, or within a year of ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of that company.

In January 2019, PGE filed for bankruptcy under Chapter 11 of the United States Bankruptcy Code as a result of claims arising from fires caused by PGE's electrical equipment. Following discussions initiated by the PGE board of directors, Mr. Johnson agreed to serve as President and CEO throughout PGE's bankruptcy process, beginning May 2, 2019, with the understanding that upon PGE's emergence from bankruptcy he would resign from PGE. On July 1, 2020, PGE emerged from Chapter 11 bankruptcy, upon completing a restructuring process that was confirmed by the United States Bankruptcy Court on June 20, 2020. Mr. Johnson resigned as President and CEO of PGE on June 30, 2020.

Ms. Campbell joined the board of directors of PGE in April 2019, after PGE filed for bankruptcy under Chapter 11 of the United States Bankruptcy Code in January 2019 and prior to its emergence from Chapter 11 bankruptcy in July 2020. Ms. Campbell continues to be a director of PGE.

[1] As President and CEO of TC Energy, Mr. Poirier is not a member of any Board committees, but is invited to attend committee meetings as required.

No director or executive officer of the Company has within the past 10 years:

- become bankrupt
- made a proposal under any legislation relating to bankruptcy or insolvency
- become subject to or launched any proceedings, arrangement or compromise with any creditors, or
- had a receiver, receiver manager or trustee appointed to hold any of their assets.

No director or executive officer of the Company has been subject to:

- any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or
- any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

BOARD COMMITTEES

TC Energy has four standing committees of the Board: the Audit Committee, the Governance Committee, the Health, Safety, Sustainability and Environment Committee and the Human Resources Committee. As President and CEO of TC Energy, Mr. Poirier is not a member of any Board committees, but is invited to attend committee meetings as required.

The voting members of each of these committees, as of February 15, 2024, are identified below. Information about the Audit Committee can be found in this AIF under the heading *Audit Committee*.

Director	Audit Committee	Governance Committee	Health, Safety, Sustainability and Environment Committee	Human Resources Committee
Cheryl F. Campbell	ü		ü	
Michael R. Culbert	ü		ü	
William D. Johnson	ü			Chair
Susan C. Jones	ü			ü
John E. Lowe (Chair)		ü		ü
David MacNaughton		ü	ü	
Una Power	Chair		ü	
Mary Pat Salomone		ü	Chair	
Indira Samarasekera		ü		ü
Siim A. Vanaselja		ü		ü
Thierry Vandal		Chair	ü	
Dheeraj "D" Verma		ü		ü

OFFICERS

With the exception of Stanley G. Chapman, III, Tina V. Faraca, Patrick C. Muttart, Annesley C. Wallace and Alisa M. Williams, all of the executive officers and corporate officers of TC Energy reside in Alberta, Canada. Positions and offices held with TC Energy are also held by such person at TCPL. As of the date hereof, the officers of TC Energy, their present positions within TC Energy, unless otherwise stated, and their principal occupations during the five preceding years are as follows:

Executive officers

Name	Present position held	Principal occupation during the five preceding years
François L. Poirier	President and Chief Executive Officer	Prior to January 2021, COO and President, Power and Storage. Prior to September 2020, COO and President, Power and Storage and Mexico. Prior to January 2020, Executive Vice-President, Corporate Development and Strategy, and President, Power & Storage and Mexico. Prior to May 2019, Executive Vice-President, Corporate Development and Strategy and President, Mexico Natural Gas Pipelines and Energy. Prior to January 2019, Executive Vice-President, Strategy and Corporate Development.
Stanley G. Chapman, III Texas, U.S.A.	Executive Vice-President and Chief Operating Officer, Natural Gas Pipelines	Prior to August 2023, Executive Vice-President, Group Executive, U.S. and Mexico Natural Gas Pipelines. Prior to September 2022, Executive Vice-President and President, U.S. and Mexico Natural Gas Pipelines. Prior to September 2020, Executive Vice-President and President, U.S. Natural Gas Pipelines.
Dawn E. de Lima	Executive Vice-President, Corporate Services	Prior to December 2020, Chief Shared Services Officer, TransAlta Corporation (TransAlta) (electricity service provider). Prior to February 2019, Chief Officer, Business and Operational Services, TransAlta.
Tina V. Faraca Texas, U.S.A.	Executive Vice-President and President, U.S. Natural Gas Pipelines	Prior to August 2023, President, U.S. Natural Gas Pipelines. Prior to September 2022, Senior Vice-President, Operations, Projects and Technical Operational Services. Prior to December 2021, Senior Vice-President, Commercial. Prior to April 2020, Senior Vice-President, Commercial, Enable Midstream (oil and natural gas).
Joel E. Hunter	Executive Vice-President and Chief Financial Officer	Prior to August 2021, Senior Vice-President, Capital Markets.
Patrick M. Keys	Executive Vice-President and General Counsel	Prior to September 2021, Executive Vice-President, Stakeholder Relations and General Counsel. Prior to May 2019, Senior Vice-President, Legal (Corporate Services Division). Prior to February 2019, Vice-President, Commercial West (Natural Gas Pipelines Division (Canada)).
Patrick C. Muttart Texas, U.S.A.	Senior Vice-President, External Relations	Prior to December 2022, Senior Vice-President, Stakeholder Relations. Prior to September 2021, Director External Affairs, PMI Global Services (tobacco manufacturing).
Annesley C. Wallace Ontario, Canada	Executive Vice-President, Strategy and Corporate Development and President, Power and Energy Solutions	Prior to September 2023, Executive Vice-President, Strategy, Corporate Development and Energy Transition Planning. Prior to May 2023, Executive Vice-President and Global Head of Infrastructure, Ontario Municipal Employees' Retirement System (OMERS) Infrastructure (investor and asset manager) (formerly Borealis Infrastructure). Prior to April 2021, Chief Pension Officer/Senior Vice-President, Pension Services, OMERS Infrastructure.
Bevin M. Wirzba	Executive Vice-President and Group President, Liquids Pipelines and Coastal GasLink	Prior to August 2023, Executive Vice-President, Strategy and Corporate Development and Group Executive, Canadian Natural Gas and Liquids Pipelines. Prior to January 2022, Executive Vice-President, Strategy and Corporate Development and President, Liquids Pipelines. Prior to June 2021, Executive Vice-President and President, Liquids Pipelines. Prior to August 2020, Senior Vice-President, Liquids Pipelines. Prior to January 2020, Senior Vice-President, Liquids Operations and Commercial (Liquids Pipelines Division). Prior to July 2019, Senior Vice-President, Business Development and Capital Markets, ARC.

Corporate officers

Name	Present position held	Principal occupation during the five preceding years
Yvonne Frame-Zawalykut	Vice-President, Corporate Controller	Prior to February 2023, Vice-President and Assistant Controller. Prior to November 2022, Director, Corporate Planning. Prior to December 2020, Director, Internal Group Finance.
Gloria L. Hartl	Vice-President, Risk Management	Prior to February 2019, Director, Corporate Planning.
Nancy A. Johnson	Vice-President and Treasurer	Prior to January 2020, Vice-President, Strategy, Regulatory and Business Planning (Natural Gas Pipelines Division (Canada)). Prior to February 2019, Vice-President, Risk Management. Prior to June 2018, Director, Financial Reporting and Corporate Accounting.
Christine R. Johnston	Vice-President, Law and Corporate Secretary	Vice-President, Law and Corporate Secretary.
Alisa M. Williams Texas, U.S.A.	Vice-President, Tax	Prior to August 2023, Director, Income Tax, U.S. and Mexico. Prior to July 2019, Manager, Income Tax, U.S. Reporting.

CONFLICTS OF INTEREST

Directors and officers of TC Energy and its subsidiaries are required to disclose any existing or potential conflicts in accordance with TC Energy's policies governing directors and officers and in accordance with the CBCA.

COBE covers potential conflicts of interest and requires that all employees, officers, directors and contract workers of TC Energy avoid situations that may result in a potential conflict.

In the event an employee, officer, director or contract worker finds themselves in a potential conflict situation, COBE stipulates that:

- the conflict should be reported; and
- the person should refrain from participation in any decision or action where there is a real or perceived conflict.

COBE also notes that employees and officers of TC Energy may not engage in outside business activities that are in conflict with or detrimental to the interests of TC Energy. The CEO and the executive leadership team must receive consent from the Chair of the Governance Committee for all outside business activities.

Under COBE, directors must also declare any material interest that they may have in a material contract or transaction and recuse himself or herself from related deliberations and approvals.

In addition to COBE, the directors and corporate officers of TC Energy are required to disclose any related parties and related party transactions in their annual directors and officers questionnaires. These questionnaires assist TC Energy in identifying and monitoring material related party transactions.

The Governance Committee reviews and approves any material related party transactions prior to the transaction occurring, and maintains oversight over material related party transactions following such approval.

There were no material conflicts of interests or related party transactions reported by the Board, CEO or the corporate officers, including the executive leadership team, in 2023.

Serving on other boards

The Board believes that it is important for it to be composed of qualified and knowledgeable directors. As a result, due to the specialized nature of the energy infrastructure business, some of the directors are associated with or sit on the boards of companies that ship natural gas or liquids through our pipeline systems. Transmission services on most of TC Energy's pipeline systems in Canada and the U.S. are subject to regulation and, accordingly, we generally cannot deny transportation services to a creditworthy shipper. The Governance Committee monitors relationships among directors to ensure that business associations do not affect the Board's performance.

The Board considers whether directors serving on the boards of, or acting as officers or in another similar capacity, for other entities including public and private companies, Crown corporations and other state-owned entities, and non-profit organizations pose any potential conflict. The Board reviews these relationships annually to determine that they do not interfere with any of our director's ability to act in our best interests. If a director declares a material interest in any material contract or material transaction being considered at a meeting, the director is not present during the discussion and does not vote on the matter.

COBE requires employees to receive consent before accepting a directorship with an entity that is not an affiliate. The CEO and executive vice-presidents must receive the consent of the Chair of the Governance Committee. All other employees must receive the consent of the Corporate Secretary or their delegate.

Affiliates

The Board oversees relationships between TC Energy and any affiliates to avoid any potential conflicts of interest.

Corporate governance

Our Board and management are committed to the highest standards of ethical conduct and corporate governance.

TC Energy is a public company listed on the TSX and the NYSE, and we recognize and respect rules and regulations in both Canada and the U.S.

Our corporate governance practices comply with the Canadian governance guidelines, which include the governance rules of the CBCA, TSX and Canadian Securities Administrators, including:

- National Instrument 52-110, *Audit Committees*
- National Policy 58-201, *Corporate Governance Guidelines*, and
- National Instrument 58-101, *Disclosure of Corporate Governance Practices*.

We also comply with the governance listing standards of the NYSE and the governance rules of the SEC that apply, in each case, to foreign private issuers.

Our governance practices comply with the NYSE standards for U.S. companies in all significant respects. As a non-U.S. company, we are not required to comply with most of the governance listing standards of the NYSE. As a foreign private issuer, however, we must disclose how our governance practices differ from those followed by U.S. companies that are subject to the NYSE standards. Our corporate governance practices do not significantly differ from those required to be followed by U.S. domestic issuers under the NYSE's listing standards. A summary of our governance practices compared to U.S. standards can be found on our website (www.tcenergy.com).

We benchmark our policies and procedures against major North American companies to assess our standards and we adopt best practices as appropriate. Some of our best practices are derived from the NYSE rules and comply with applicable rules adopted by the SEC to meet the requirements of the *Sarbanes-Oxley Act of 2002* and the *Dodd-Frank Wall Street Reform and Consumer Protection Act*.

Audit Committee

The Audit Committee is responsible for assisting the Board in overseeing the integrity of our financial statements and our compliance with legal and regulatory requirements. It is also responsible for overseeing and monitoring the accounting and reporting process and the process, performance and independence of our internal and external auditors. The charter of the Audit Committee can be found in *Schedule B* of this AIF.

RELEVANT EDUCATION AND EXPERIENCE OF MEMBERS

The members of the Audit Committee as of February 15, 2024 are Una Power (Chair), Cheryl F. Campbell, Michael R. Culbert, William D. Johnson and Susan C. Jones.

The Board believes that the composition of the Audit Committee reflects a high level of financial literacy and expertise. Each member of the Audit Committee has been determined by the Board to be *independent* and *financially literate* within the meaning of the definitions under Canadian and U.S. securities laws and the NYSE rules. In addition, the Board has determined that Ms. Power is an *Audit Committee Financial Expert* as that term is defined under U.S. securities laws. The Board has made this determination based on the education and breadth and depth of experience of each member of the Audit Committee. The following is a description of the education and experience, apart from their respective roles as directors of TC Energy, of each member of the Audit Committee that is relevant to the performance of his or her responsibilities as a member of the Audit Committee.

Una Power (Chair)

Ms. Power earned a Bachelor of Commerce (Honours) degree from Memorial University and holds Chartered Professional Accountant, Chartered Accountant and Chartered Financial Analyst designations. She serves on the board of directors for Teck where she currently serves as audit committee Chair and also serves on the board of directors for Scotiabank, where she previously served as a member and Chair of its audit committee. Ms. Power was previously the Chief Financial Officer of Nexen Energy ULC, a former publicly traded oil and gas company that is now a wholly-owned subsidiary of CNOOC Limited, where she held various executive positions with responsibility for financial and risk management, strategic planning, budgeting, business development, energy marketing and trading, information technology and capital investment.

Cheryl F. Campbell

Ms. Campbell holds a Master of Science degree in finance, with a minor in management, from the University of Colorado, Denver, as well as Bachelor of Science degrees in chemical engineering and business from the University of Colorado, Boulder. She currently serves on the board of directors of PGE, where she is Chair of the Safety & Nuclear Oversight Committee as well as a member of the Sustainability & Governance Committee. She also serves on the board and is a member of the Audit Committee of Summit Utilities, as well as serving on the board of JANA. She previously served as a director and Audit Committee member of National Underground Group and, for 13 years, as Senior Vice President, Gas, with Xcel.

Michael R. Culbert

Mr. Culbert holds a Bachelor of Science degree in Business Administration from Emmanuel College in Boston, Massachusetts. He currently serves on the board of directors of Precision, and is a member of its audit committee. He previously served as a director of Enerplus and Reserve Royalty Income Trust, and as a director and Vice-Chair of PETRONAS, where he also served as a member of each of their audit committees. Mr. Culbert was also a director and President of PNW LNG LP and former co-founder, director, President and CEO of Progress Energy Ltd.

William D. Johnson

Mr. Johnson holds a Juris Doctor degree (high honors) from the University of North Carolina School of Law and a Bachelor of Arts degree (history, summa cum laude) from Duke University in North Carolina. He recently served as President and CEO of PGE. Mr. Johnson also served as President and CEO of Tennessee Valley, as well as serving as Chairman, President and CEO of Progress Energy, Inc.

Susan C. Jones

Ms. Jones earned a Bachelor of Arts degree in Political Science and Hispanic Studies from the University of Victoria. She also holds a Bachelor of Laws degree from the University of Ottawa. She earned a Leadership Diploma from the University of Oxford and holds a Director Certificate from Harvard University. Ms. Jones serves as a director of Canadian National Railway Company and is a member of its human resources and compensation and pension and investment committees. Ms. Jones previously served as a director of ARC and was a member of the audit and finance committee of Seven Generations Energy Ltd. prior to its merger with ARC. She also served as a director of Piedmont. She previously served on the boards and as a member of the audit committees of Gibson and Canpotex, where she also served as Chair of the board. Ms. Jones held an executive leadership role at Nutrien for 15 years, most recently as Executive Vice-President and CEO of the Potash Business Unit.

PRE-APPROVAL POLICIES AND PROCEDURES

TC Energy's Audit Committee maintains a pre-approval policy with respect to permitted non-audit services and audit services. For non-audit service engagements of up to $250,000, approval of the Audit Committee Chair is required, and the Audit Committee is to be informed of the engagement at the next scheduled Audit Committee meeting. For all non-audit service engagements of $250,000 or more, pre-approval of the Audit Committee is required.

To date, all non-audit services have been pre-approved by the Audit Committee in accordance with the pre-approval policy described above.

EXTERNAL AUDITOR SERVICE FEES

The table below shows the services KPMG LLP provided during the last two fiscal years and the fees they invoiced us:

($ millions)	2023	2022
Audit fees	**18.5**	14.2
• audit of the annual consolidated financial statements		
• services related to statutory and regulatory filings or engagements		
• review of interim consolidated financial statements and information contained in various prospectuses and other securities offering documents		
Audit-related fees	**0.9**	0.3
• services related to the audit of the financial statements of TC Energy pipeline abandonment trusts, certain post-retirement plans, and certain special purpose audits		
• French and Spanish translation services		
Tax fees	**1.5**	0.8
• Canadian and international tax planning and tax compliance matters, including the review of income tax returns and other tax filings		
All other fees	**0.2**	0.2
• Fees for other products and services provided by the auditors not described above, which included fees related to advice and assistance with ESG services		
Total fees	**21.1**	15.5

Note

- 2023 total fees are higher than 2022 due to increased audit work related to (i) the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf to GIP; (ii) the spinoff Transaction and additional securities work.

Legal proceedings and regulatory actions

Except as described below, there are no legal proceedings in respect of which the Company is or was a party, or in respect of which any of the Company's property is or was the subject during the year ended December 31, 2023, nor are there any such proceedings known by the Company to be contemplated, that involve a claim for damages exceeding 10% of the Company's current assets. In addition, there have not been any (a) penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority during the year ended December 31, 2023, (b) any other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision, or (c) settlement agreements entered into by the Company before a court relating to securities legislation or with a securities regulatory authority during the year ended December 31, 2023.

SA Energy Group

Coastal GasLink Limited Partnership (the Partnership) is in arbitration with SA Energy Group (SAEG), which is one of the prime construction contractors on the Coastal GasLink pipeline. While still engaged as prime contractor, SAEG filed a request to arbitrate in February 2022, seeking damages for incremental costs resulting from alleged project delays. In order to mitigate cost, schedule and environmental risk while the project was in active construction, the Partnership advanced without prejudice payments to SAEG which the Partnership now seeks to recover via set off. By agreement among the parties, the scope of the arbitration is limited to damages for project work completed prior to December 29, 2022. In November 2023, SAEG filed materials purporting to seek damages in excess of $1.1 billion. The Partnership continues to dispute the merits of SAEG's claims and to assert its rights to set off. Arbitration is scheduled to proceed in late 2024. At December 31, 2023, the final outcome of this matter cannot be reasonably estimated.

Pacific Atlantic Pipeline Construction Ltd.

The Partnership is in arbitration with one of its previous prime contractors, Pacific Atlantic Pipeline Construction Ltd. (PAPC). The Partnership 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 the Partnership's demand on the guarantee, in August 2022, PAPC initiated arbitration. As of November 2023, PAPC purports to seek at least $428 million in damages for wrongful termination for cause, termination damages and payments alleged to be outstanding. The Partnership 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. The Partnership estimates its damages to be $1.2 billion. Arbitration is scheduled to proceed in late 2024. At December 31, 2023, the final outcome of this matter cannot be reasonably estimated.

Separately, the Partnership has sought to draw down on a $117 million irrevocable standby letter of credit (LOC) provided by PAPC based on a bona fide belief that the Partnership's damages are in excess of the face value of the LOC. PAPC has applied for an injunction restraining the Partnership from drawing on the LOC pending the completion of the arbitration between the Partnership, PAPC, and Bonatti, which is the subject of further court proceedings.

Transfer agent and registrar

TC Energy's transfer agent and registrar is Computershare Investor Services, Inc. with its Canadian transfer facilities in the cities of Vancouver, Calgary, Toronto and Montréal.

Material contracts

TC Energy did not enter into any material contracts outside the ordinary course of business during the year ended December 31, 2023, nor has it entered into any material contracts outside the ordinary course of business prior to the year ended December 31, 2023 which are still in effect as at the date of this AIF.

Interest of experts

KPMG LLP are the auditors of TC Energy and have confirmed with respect to TC Energy that they are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations and also that they are independent accountants with respect to TC Energy under all relevant U.S. professional and regulatory standards.

Additional information

1. Additional information in relation to TC Energy may be found under TC Energy's profile on SEDAR+ (www.sedarplus.ca).
2. Additional information including directors' and officers' remuneration and indebtedness, principal holders of TC Energy's securities and securities authorized for issuance under equity compensation plans (all where applicable), is contained in TC Energy's Management Information Circular for its most recent annual meeting of shareholders that involved the election of directors and can be obtained upon request from the Corporate Secretary of TC Energy.
3. Additional financial information is provided in TC Energy's audited consolidated financial statements and MD&A for its most recently completed financial year.

Glossary

Units of measure

Bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
hp	horsepower
km	Kilometres
MMcf/d	Million cubic feet per day
MW	Megawatt(s)
MWh	Megawatt hours
TJ/d	Terajoules per day

General terms and terms related to our operations

B.C.	British Columbia
bitumen	A thick, heavy oil that must be diluted to flow (also see: diluent). One of the components of the oil sands, along with sand, water and clay
diluent	A thinning agent made up of organic compounds. Used to dilute bitumen so it can be transported through pipelines
DRP	Dividend Reinvestment and Share Purchase Plan
ESG	Environmental, social and governance
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it
GHG	Greenhouse gas
investment base	Includes rate base as well as assets under construction
LNG	Liquefied natural gas
MCR	Major component replacement
rate base	Average assets in service, working capital and deferred amounts used in setting of regulated rates
WCSB	Western Canada Sedimentary Basin
Year End	Year ended December 31, 2023

Accounting terms

GAAP	U.S. generally accepted accounting principles
ROE	Return on common equity

Government and regulatory bodies terms

AER	Alberta Energy Regulator
BCEAO	Environmental Assessment Office (British Columbia)
BCER	B.C. Energy Regulator (formerly B.C. Oil and Gas Commission)
CBCA	*Canada Business Corporations Act*
CER	Canada Energy Regulator (formerly the National Energy Board (Canada))
CFE	Comisión Federal de Electricidad (Mexico)
CRE	Comisión Reguladora de Energía, or Energy Regulatory Commission (Mexico)
DOS	U.S. Department of State
FERC	Federal Energy Regulatory Commission (U.S.)
IESO	Independent Electricity System Operator (Ontario)
NYSE	New York Stock Exchange
PHMSA	Pipeline and Hazardous Materials Safety and Administration
SEC	U.S. Securities and Exchange Commission
TSX	Toronto Stock Exchange

Schedule A

METRIC CONVERSION TABLE

The conversion factors set out below are approximate factors. To convert from Metric to Imperial multiply by the factor indicated. To convert from Imperial to Metric divide by the factor indicated.

Metric	Imperial	Factor
Kilometres	Miles	0.62
Millimetres	Inches	0.04
Gigajoules	Million British thermal units	0.95
Cubic metres*	Cubic feet	35.3
Kilopascals	Pounds per square inch	0.15
Degrees Celsius	Degrees Fahrenheit	to convert to Fahrenheit multiply by 1.8, then add 32 degrees; to convert to Celsius subtract 32 degrees, then divide by 1.8

*The conversion is based on natural gas at a base pressure of 101.325 kilopascals and at a base temperature of 15 degrees Celsius.

Schedule B

CHARTER OF THE AUDIT COMMITTEE

1. PURPOSE

The Audit Committee shall assist the Board of Directors (the Board) in overseeing and monitoring, among other things, the:

- Company's financial accounting and reporting process;
- integrity of the financial statements;
- Company's internal control over financial reporting;
- external financial audit process;
- compliance by the Company with legal and regulatory requirements; and
- independence and performance of the Company's internal and external auditor.

To fulfill its purpose, the Audit Committee has been delegated certain authorities by the Board that it may exercise on behalf of the Board.

2. ROLES AND RESPONSIBILITIES

I. Appointment of the Company's External Auditor

Subject to confirmation by the external auditor of their compliance with Canadian and U.S. regulatory registration requirements, the Audit Committee shall recommend to the Board the appointment of the external auditor, such appointment to be confirmed by the Company's shareholders at each annual meeting. The Audit Committee shall also recommend to the Board the compensation to be paid to the external auditor for audit services. The Audit Committee shall also be directly responsible for the oversight of the work of the external auditor (including resolution of disagreements between management and the external auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or related work. The external auditor shall report directly to the Audit Committee.

The Audit Committee shall review and approve the audit plan of the external auditor. The Audit Committee shall also receive periodic reports from the external auditor regarding the auditor's independence, discuss such reports with the auditor, consider whether the provision of non-audit services is compatible with maintaining the auditor's independence and take appropriate action to satisfy itself of the independence of the external auditor. In addition, to further satisfy itself of audit quality and the independence of the external auditor, the Audit Committee shall undertake a Periodic Comprehensive Review of the External Auditor at least once every five years.

II. Oversight in Respect of Financial Disclosure

The Audit Committee shall, to the extent it deems it necessary or appropriate:

(a) review, discuss with management and the external auditor and recommend to the Board for approval, the Company's audited annual consolidated financial statements, annual information form, management's discussion and analysis (MD&A), all financial information in prospectuses and other offering memoranda, financial statements required by securities regulators, all prospectuses and all documents which may be incorporated by reference into a prospectus, including, without limitation, the annual management information circular, but excluding any pricing or prospectus supplement relating to the issuance of debt securities of the Company;

(b) review, discuss with management and the external auditor and approve, the release to the public of the Company's interim reports, including the consolidated financial statements, MD&A and news releases on quarterly financial results;

(c) review and discuss with management and the external auditor the use of non-GAAP information and the applicable reconciliation;

(d) review and discuss with management any financial outlook or future-oriented financial information disclosure in advance of its public release; provided, however, that such discussion may be done generally (consisting of discussing the types of information to be disclosed and the types of presentations to be made). The Audit Committee need not discuss in advance each instance in which the Company may provide financial projections or presentations to credit rating agencies;

(e) review with management and the external auditor major issues regarding accounting policies and auditing practices, including any significant changes in the Company's selection or application of accounting policies, as well as major issues as to the adequacy of the Company's internal controls and any special audit steps adopted in light of material control deficiencies that could significantly affect the Company's financial statements;

(f) review and discuss quarterly findings reports from the external auditor on:

(i) all critical accounting policies and practices to be used;

(ii) all alternative treatments of financial information within generally accepted accounting principles that have been discussed with management, ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditor;

(iii) other material written communications between the external auditor and management, such as any management letter or schedule of unadjusted differences;

(g) review with management and the external auditor the effect of regulatory and accounting developments on the Company's financial statements;

(h) review with management and the external auditor the effect of any off-balance sheet structures on the Company's financial statements;

(i) review with management, the external auditor and, if necessary, legal counsel, any litigation, claim or contingency, including arbitration and tax assessments, that could have a material effect upon the financial position of the Company, and the manner in which these matters have been disclosed in the financial statements;

(j) review disclosures made to the Audit Committee by the Company's Chief Executive Officer (CEO) and Chief Financial Officer (CFO) during their certification process for the periodic reports filed with securities regulators about any significant deficiencies in the design or operation of internal controls or material weaknesses therein and any fraud involving management or other employees who have a significant role in the Company's internal controls;

(k) discuss with management the Company's material financial risk exposures and the steps management has taken to monitor and control such exposures, including the Company's risk assessment and risk management policies;

III. Oversight in Respect of Legal and Regulatory Matters

(a) review with the Company's General Counsel legal matters that may have a material impact on the financial statements, the Company's compliance policies and any material reports or inquiries received from regulators or governmental agencies;

IV. Oversight in Respect of Internal Audit

(a) review and approve the audit plans of the internal auditor of the Company including the degree of coordination between such plans and those of the external auditor and the extent to which the planned audit scope can be relied upon to detect weaknesses in internal control, fraud or other illegal acts;

(b) review the significant findings prepared by the internal audit department and recommendations issued by it or by any external party relating to internal audit issues, together with management's response thereto;

(c) review compliance with the Company's policies and avoidance of conflicts of interest;

(d) review the report prepared by the internal auditor on officers' expenses and aircraft usage;

(e) review the adequacy of the resources of the internal auditor to ensure the objectivity and independence of the internal audit function, including reports from the internal audit department on its audit process with subsidiaries and affiliates;

(f) ensure the internal auditor has access to the Chair of the Audit Committee, the Board and the CEO and meet separately with the internal auditor to review with him or her any problems or difficulties he or she may have encountered and specifically:

(i) any difficulties which were encountered in the course of the audit work, including restrictions on the scope of activities or access to required information, and any disagreements with management;

(ii) any changes required in the planned scope of the internal audit;

(iii) the internal audit department responsibilities, budget and staffing;

and to report to the Board on such meetings;

V. Oversight in Respect of the External Auditor

(a) review any letter, report or other communication from the external auditor in respect of any identified weakness in internal control or unadjusted difference and management's response and follow-up, inquire regularly of management and the external auditor of any significant issues between them and how they have been resolved, and intervene in the resolution if required;

(b) receive and review annually the external auditor's formal written statement of independence delineating all relationships between itself and the Company;

(c) meet separately with the external auditor to review any problems or difficulties the external auditor may have encountered and specifically:

(i) any difficulties which were encountered in the course of the audit work, including any restrictions on the scope of activities or access to required information, and any disagreements with management;

(ii) any changes required in the planned scope of the audit;

and to report to the Board on such meetings;

(d) meet with the external auditor prior to the audit to review the planning and staffing of the audit;

(e) receive and review annually the external auditor's written report on their own internal quality control procedures; any material issues raised by the most recent internal quality control review, or peer review, of the external auditor, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, and any steps taken to deal with such issues;

(f) review and evaluate the external auditor, including the lead partner of the external auditor team;

(g) ensure the rotation of the lead (or coordinating) audit partner having primary responsibility for the audit and the audit partner responsible for reviewing the audit as required by law, but at least every five years;

VI. Oversight in Respect of Audit and Non-Audit Services

(a) pre-approve all audit services (which may entail providing comfort letters in connection with securities underwritings) and all permitted non-audit services, other than non-audit services where:

(i) the aggregate amount of all such non-audit services provided to the Company that were not pre-approved constitutes not more than five percent of the total fees paid by the Company and its subsidiaries to the external auditor during the fiscal year in which the non-audit services are provided;

(ii) such services were not recognized by the Company at the time of the engagement to be non-audit services;

(iii) such services are promptly brought to the attention of the Audit Committee and approved, prior to the completion of the audit, by the Audit Committee or by one or more members of the Audit Committee to whom authority to grant such approvals has been delegated by the Audit Committee;

(b) approval by the Audit Committee of a non-audit service to be performed by the external auditor shall be disclosed as required under securities laws and regulations;

(c) the Audit Committee may delegate to one or more designated members of the Audit Committee the authority to grant pre-approvals required by this subsection. The decisions of any member to whom authority is delegated to pre-approve an activity shall be presented to the Audit Committee at its first scheduled meeting following such pre-approval;

(d) if the Audit Committee approves an audit service within the scope of the engagement of the external auditor, such audit service shall be deemed to have been pre-approved for purposes of this subsection;

VII. Oversight in Respect of Certain Policies

(a) review and recommend to the Board for approval the implementation of, and significant amendments to, policies and program initiatives deemed advisable by management or the Audit Committee with respect to the Company's code of business ethics (COBE), risk management and financial reporting policies;

(b) obtain reports from management, the Company's senior internal auditing executive and the external auditor and report to the Board on the status and adequacy of the Company's efforts to ensure its businesses are conducted and its facilities are operated in an ethical, legally compliant and socially responsible manner, in accordance with the Company's COBE;

(c) establish a non-traceable, confidential and anonymous system by which callers may ask for advice or report any ethical or financial concern, ensure that procedures for the receipt, retention and treatment of complaints in respect of accounting, internal controls and auditing matters are in place, and receive reports on such matters as necessary;

(d) annually review and assess the adequacy of the Company's public disclosure policy;

(e) review and approve the Company's hiring policy for partners, employees and former partners and employees of the present and former external auditor (recognizing the Sarbanes-Oxley Act of 2002 does not permit the CEO, controller, CFO or chief accounting officer to have participated in the Company's audit as an employee of the external auditor during the preceding one-year period) and monitor the Company's adherence to the policy;

VIII. Oversight in Respect of Financial Aspects of the Company's Canadian Pension Plans (the Company's pension plans), specifically:

(a) review and approve annually the Statement of Investment Beliefs for the Company's pension plans;

(b) delegate the ongoing administration and management of the financial aspects of the Canadian pension plans to the Pension Committee comprised of members of the Company's management team appointed by the Human Resources Committee, in accordance with the Pension Committee Charter, which terms shall be approved by both the Audit Committee and the Human Resources Committee, and the terms of the Statement of Investment Beliefs;

(c) monitor the financial management activities of the Pension Committee and receive updates at least annually from the Pension Committee on the investment of the Plan assets to ensure compliance with the Statement of Investment Beliefs;

(d) provide advice to the Human Resources Committee on any proposed changes in the Company's pension plans in respect of any significant effect such changes may have on pension financial matters;

(e) review and consider financial and investment reports and the funded status relating to the Company's pension plans and recommend to the Board on pension contributions;

(f) receive, review and report to the Board on the actuarial valuation and funding requirements for the Company's pension plans;

(g) approve the initial selection or change of actuary for the Company's pension plans;

(h) approve the appointment or termination of the pension plans' auditor;

IX. U.S. Stock Plans

(a) review and approve the engagement and related fees of the auditor for any plan of a U.S. subsidiary that offers Company stock to employees as an investment option under the plan;

X. Oversight in Respect of Internal Administration

(a) review annually the reports of the Company's representatives on certain audit committees of subsidiaries and affiliates of the Company and any significant issues and auditor recommendations concerning such subsidiaries and affiliates;

(b) oversee succession planning for the senior management in finance, treasury, tax, risk, internal audit and the controllers' group;

XI. Information Security

(a) review quarterly, the report of the Chief Information Officer (or such other appropriate Company representative) on information security controls, education and awareness.

XII. Oversight Function

While the Audit Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Audit Committee to plan or conduct audits or to determine that the Company's financial statements and disclosures are complete and accurate or are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibilities of management and the external auditor. The Audit Committee, its Chair and any of its members who have accounting or related financial management experience or expertise, are members of the Board, appointed to the Audit Committee to provide broad oversight of the financial disclosure, financial risk and control related activities of the Company, and are specifically not accountable nor responsible for the day to day operation of such activities. Although designation of a member or members as an "audit committee financial expert" is based on that individual's education and experience, which that individual will bring to bear in carrying out his or her duties on the Audit Committee, designation as an "audit committee financial expert" does not impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the Audit Committee and Board in the absence of such designation. Rather, the role of any audit committee financial expert, like the role of all Audit Committee members, is to oversee the process and not to certify or guarantee the internal or external audit of the Company's financial information or public disclosure.

3. COMPOSITION OF AUDIT COMMITTEE

The Audit Committee shall consist of three or more directors, a majority of whom are resident Canadians (as defined in the *Canada Business Corporations Act*), and all of whom are unrelated and/or independent for the purposes of applicable Canadian and United States securities law and applicable rules of any stock exchange on which the Company's securities are listed. Each member of the Audit Committee shall be financially literate and at least one member shall have accounting or related financial management expertise (as those terms are defined from time to time under the requirements or guidelines for audit committee service under securities laws and the applicable rules of any stock exchange on which the Company's securities are listed for trading or, if it is not so defined, as that term is interpreted by the Board in its business judgment).

4. APPOINTMENT OF AUDIT COMMITTEE MEMBERS

The members of the Audit Committee shall be appointed by the Board from time to time on the recommendation of the Governance Committee and shall hold office until the next annual meeting of shareholders or until their successors are earlier appointed or until they cease to be directors of the Company.

5. VACANCIES

Where a vacancy occurs at any time in the membership of the Audit Committee, it may be filled by the Board on the recommendation of the Governance Committee.

6. AUDIT COMMITTEE CHAIR

The Board shall appoint a Chair of the Audit Committee who shall:

(a) review and approve the agenda for each meeting of the Audit Committee and, as appropriate, consult with members of management;

(b) preside over meetings of the Audit Committee;

(c) make suggestions and provide feedback from the Audit Committee to management regarding information that is or should be provided to the Audit Committee;

(d) report to the Board on the activities of the Audit Committee relative to its recommendations, resolutions, actions and concerns; and

(e) meet as necessary with the internal and external auditor.

7. ABSENCE OF AUDIT COMMITTEE CHAIR

If the Chair of the Audit Committee is not present at any meeting of the Audit Committee, one of the other members of the Audit Committee present at the meeting shall be chosen by the Audit Committee to preside at the meeting.

8. SECRETARY OF AUDIT COMMITTEE

The Corporate Secretary shall act as Secretary to the Audit Committee.

9. MEETINGS

The Chair, or any two members of the Audit Committee, or the internal auditor, or the external auditor, may call a meeting of the Audit Committee. The Audit Committee shall meet at least quarterly. The Audit Committee shall meet periodically with management, the internal auditor and the external auditor in separate executive sessions.

10. QUORUM

A majority of the members of the Audit Committee, present in person or by telephone or other telecommunication device that permit all persons participating in the meeting to speak to each other, shall constitute a quorum.

11. NOTICE OF MEETINGS

Notice of the time and place of every meeting shall be given in writing, facsimile communication or by other electronic means to each member of the Audit Committee at least 24 hours prior to the time fixed for such meeting; provided, however, that a member may in any manner waive a notice of a meeting. Attendance of a member at a meeting is a waiver of notice of the meeting, except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting is not lawfully called.

12. ATTENDANCE OF COMPANY OFFICERS AND EMPLOYERS AT MEETING

At the invitation of the Chair of the Audit Committee, one or more officers or employees of the Company may attend any meeting of the Audit Committee.

13. PROCEDURE, RECORDS AND REPORTING

The Audit Committee shall fix its own procedure at meetings, keep records of its proceedings and report to the Board when the Audit Committee may deem appropriate but not later than the next meeting of the Board.

14. REVIEW OF CHARTER AND EVALUATION OF AUDIT COMMITTEE

The Audit Committee shall review its Charter annually or otherwise, as it deems appropriate and, if necessary, propose changes to the Governance Committee and the Board. The Audit Committee shall annually review the Audit Committee's own performance.

15. OUTSIDE EXPERTS AND ADVISORS

The Audit Committee is authorized, when deemed necessary or desirable, to retain and set and pay the compensation forindependent counsel, outside experts and other advisors, at the Company's expense, to advise the Audit Committee or its members independently on any matter.

16. RELIANCE

Absent actual knowledge to the contrary (which shall be promptly reported to the Board), each member of the Audit Committee shall be entitled to rely on (i) the integrity of those persons or organizations within and outside the Company from which it receives information, (ii) the accuracy of the financial and other information provided to the Audit Committee by such persons or organizations and (iii) representations made by management and the external auditor, as to any information technology, internal audit and other non-audit services provided by the external auditor to the Company and its subsidiaries.

Management's discussion and analysis

February 15, 2024

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, 2023.

This MD&A should also be read in conjunction with our December 31, 2023 audited Consolidated financial statements and notes for the same period, which have been prepared in accordance with U.S. GAAP.

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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 134. All information is as of February 15, 2024 and all amounts are in Canadian dollars, unless noted otherwise.

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 about the new Liquids Pipelines Company, South Bow Corporation, following the anticipated completion of the proposed spinoff transaction of our Liquids Pipelines business into a separate publicly listed company, including the management and credit ratings thereof
- expectations regarding the size, structure, timing, conditions and outcome of ongoing and future transactions, including the proposed spinoff transaction and our asset divestiture program
- 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
- statements related to our GHG emissions reduction goals
- 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
- expected industry, market and economic conditions, 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, divestitures, the proposed spinoff transaction and energy transition
- regulatory decisions and outcomes
- planned and unplanned outages and the use 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, divestitures, the proposed spinoff transaction and energy transition
- terms, timing and completion of the proposed spinoff transaction, including the timely receipt of all necessary approvals and tax rulings
- that market or other conditions are no longer favourable to completing the proposed spinoff transaction
- business disruption during the period prior to or directly following the proposed 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
- impact of energy transition on our business
- economic conditions 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).

NON-GAAP MEASURES

This MD&A references the following non-GAAP measures:

- comparable EBITDA
- comparable EBIT
- comparable earnings
- comparable earnings per common share
- funds generated from operations
- comparable funds generated from operations
- net capital expenditures.

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. Discussions throughout this MD&A on the factors impacting comparable earnings are consistent with the factors that impact net income (loss) attributable to common shares, except where noted otherwise. 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 not to adjust for a specific item in reporting comparable measures is subjective and made after careful consideration. Specific items may include:

- gains or losses on sales of assets or assets held for sale
- income tax refunds, valuation allowances and adjustments resulting from changes in legislation and enacted tax rates
- expected credit loss provisions on net investment in leases and certain contract assets in Mexico
- legal, contractual, bankruptcy and other settlements
- impairment of goodwill, plant, property and equipment, equity investments and other assets
- acquisition, integration and restructuring costs
- unrealized fair value adjustments related to risk management activities of Bruce Power's funds invested for post-retirement benefits
- unrealized gains and losses from changes in the fair value of derivatives related to financial and commodity price risk management activities.

We exclude from comparable measures the unrealized gains and losses from changes in the fair value of derivatives related to financial and commodity price risk management activities. These derivatives generally provide effective economic hedges but do not meet the criteria for hedge accounting. The changes in fair value, including our proportionate share of changes in fair value related to Bruce Power are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them reflective of our underlying operations.

In third quarter 2023, we announced plans to separate into two independent, investment-grade, publicly listed companies through the proposed spinoff of our Liquids Pipelines business (the spinoff Transaction). A separation management office was established to guide the successful coordination and governance between the two entities, including the development of a separation agreement and transition service agreement. Liquids Pipelines business separation costs related to the spinoff Transaction include internal costs related to separation activities, legal, tax, audit and other consulting fees, which are recognized in the results of our Liquids Pipelines and Corporate segments. These items have been excluded from comparable measures as we do not consider them reflective of our ongoing underlying operations.

In second quarter 2023, we accrued an additional amount for environmental remediation costs related to the Milepost 14 incident. We have appropriate insurance policies in place and we believe that it remains probable that the majority of the environmental remediation costs will be eligible for recovery under our existing insurance coverage. We expect to receive a portion of these insurance proceeds from our wholly-owned captive insurance subsidiary, which resulted in an impact to net income in the consolidated financial results of TC Energy in second quarter 2023. This amount has been excluded from comparable measures as it is not reflective of our ongoing underlying operations.

In first quarter 2023, TransCanada PipeLines Limited (TCPL) entered into an unsecured revolving credit facility with Transportadora de Gas Natural de la Huasteca (TGNH). 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 translation of the loan receivable and payable to TC Energy's reporting currency. As the amounts do not accurately reflect what will be realized at settlement, beginning in second quarter 2023, we excluded 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.

In 2022, we launched the Focus Project to identify opportunities to improve safety, productivity and cost-effectiveness and to date have identified a broad set of opportunities expected to improve safety and financial performance over the long term. Certain initiatives have been implemented and we expect to continue designing and implementing additional initiatives beyond 2023, 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, primarily related to Focus Project costs for external consulting and severance, some of which are not recoverable through regulatory and commercial tolling structures. These amounts have been excluded from comparable measures as they are not reflective of our ongoing underlying operations.

Prior to full repayment in first quarter 2022, we excluded from comparable measures the unrealized foreign exchange gains and losses on the peso-denominated loan receivable from an affiliate, as well as the corresponding proportionate share of Sur de Texas foreign exchange gains and losses, as the amounts did not accurately reflect the gains and losses that would be realized at settlement. These amounts offset within each reporting period, resulting in no impact on net income.

The following table identifies our non-GAAP measures against their most directly comparable GAAP measures:

Comparable 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
net capital expenditures	capital expenditures

Comparable EBITDA and comparable EBIT

Comparable EBITDA represents segmented earnings (losses) adjusted for certain specific items, 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 the Financial results sections for each business segment for a reconciliation to segmented earnings (losses).

Comparable earnings and comparable earnings per common share

Comparable earnings represents earnings attributable to common shareholders on a consolidated basis, adjusted for specific items. 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, adjusted for specific items. Refer to the Financial highlights section for reconciliations to Net income (loss) attributable to common shares and Net income (loss) per common share.

Funds generated from operations and comparable funds generated from operations

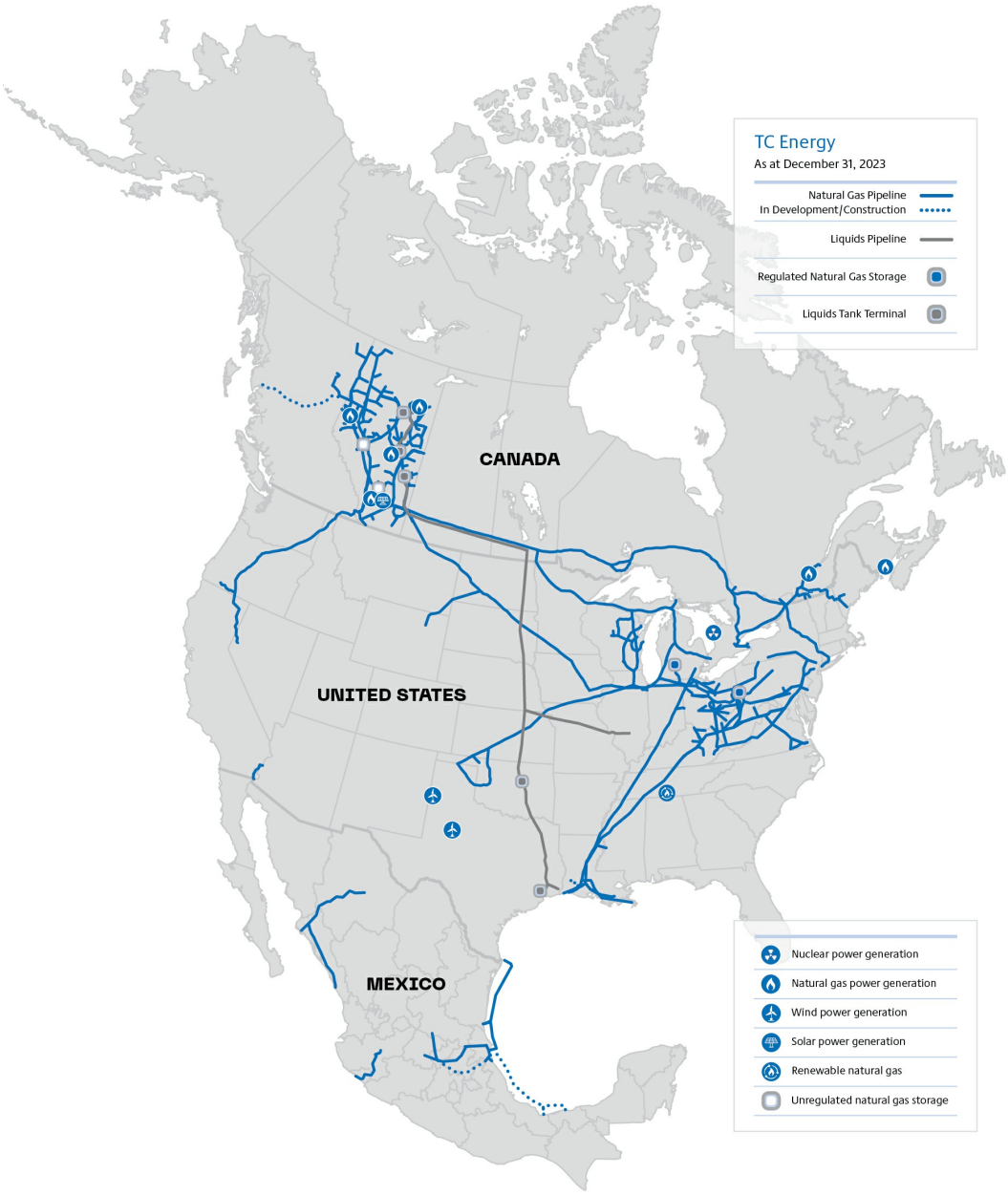
Funds generated from operations reflects net cash provided by operations before changes in operating working capital. The components of changes in working capital are disclosed in Note 30, Changes in operating working capital, of our 2023 Consolidated financial statements. We believe funds generated from operations is a useful measure of our consolidated operating cash flows because it excludes fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period, and is used to provide a consistent measure of the cash-generating ability of our businesses. Comparable funds generated from operations is adjusted for the cash impact of specific items noted above. Refer to the Financial Condition section for a reconciliation to Net cash provided by operations.

Net capital expenditures

Net capital expenditures represents capital expenditures, including 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. We use net capital expenditures as we believe it is a useful measure of our cash flow used for capital reinvestment.

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 and liquids pipelines, power generation and natural gas storage facilities.



THREE CORE BUSINESSES

We operate in three core businesses – Natural Gas Pipelines, Liquids 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 five operating segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids 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.

Year at-a-glance

at December 31		
(millions of $)	**2023**	**2022**
Total assets by segment		
Canadian Natural Gas Pipelines	**29,782**	27,456
U.S. Natural Gas Pipelines	**50,499**	50,038
Mexico Natural Gas Pipelines	**12,003**	9,231
Liquids Pipelines	**15,490**	15,587
Power and Energy Solutions	**9,525**	8,272
Corporate	**7,735**	3,764
	125,034	114,348

year ended December 31		
(millions of $)	**2023**	**2022**
Total revenues by segment		
Canadian Natural Gas Pipelines	**5,173**	4,764
U.S. Natural Gas Pipelines	**6,229**	5,933
Mexico Natural Gas Pipelines	**846**	688
Liquids Pipelines	**2,667**	2,668
Power and Energy Solutions	**1,019**	924
	15,934	14,977

year ended December 31		
(millions of $)	**2023**	**2022**
Comparable EBITDA by segment[1]		
Canadian Natural Gas Pipelines	**3,335**	2,806
U.S. Natural Gas Pipelines	**4,385**	4,089
Mexico Natural Gas Pipelines	**805**	753
Liquids Pipelines	**1,457**	1,366
Power and Energy Solutions	**1,020**	907
Corporate	**(14)**	(20)
	10,988	9,901

1 For further information on the reconciliation of segmented earnings to comparable EBITDA, refer to the Financial results sections for each business segment.

OUR STRATEGY

Our vision is to be the premier energy infrastructure company in North America today and in the future by safely generating, storing and delivering the energy people need every day. Our goal is to develop, build and safely operate a portfolio of infrastructure assets that enable us to prosper irrespective of the pace and direction of energy transition and at all points in the economic cycle. We are a team of energy problem solvers working to deliver this energy in a safe, reliable, secure and affordable manner through lower carbon energy solutions including natural gas, nuclear energy and pumped hydro.

Our business consists of natural gas and crude oil transportation, storage and delivery systems, as well as power generation assets that produce electricity. These long-life infrastructure assets cover all strategic North American corridors, are anchored by our conservative risk preferences and are supported by long-term commercial arrangements and/or rate regulation. Our assets generate predictable and sustainable cash flows and earnings providing the cornerstones of our low-risk, utility-like business model. Our long-term strategy is driven by several key beliefs:

- natural gas will continue to play a pivotal role in North America's energy future and support global GHG emissions reduction
- crude oil will remain an important part of the fuel mix
- the need for reliable, on-demand energy sources to support electric grid stability will grow significantly
- existing infrastructure assets will become more valuable given the challenges in developing new greenfield, linear-energy infrastructure; in particular, pipelines.

On July 27, 2023, we announced plans to separate into two independent, investment-grade, publicly listed companies through the spinoff Transaction and on November 8, 2023, we communicated that the name of the new Liquids Pipelines business will be South Bow Corporation. In addition to shareholder and court approvals, the spinoff Transaction is subject to receipt of favourable tax rulings from Canadian and U.S. tax authorities, receipt of necessary regulatory approvals, and satisfaction of other customary closing conditions. We expect that the spinoff Transaction will be completed in the second half of 2024.

Allocation of comparable EBITDA[1]

year ended December 31	2023	2022
Comparable EBITDA by segment		
Canadian Natural Gas Pipelines	**31 %**	28 %
U.S. Natural Gas Pipelines	**40 %**	41 %
Mexico Natural Gas Pipelines	**7 %**	8 %
Liquids Pipelines	**13 %**	14 %
Power and Energy Solutions	**9 %**	9 %
	100 %	100 %

1 Refer to Note 5, Segmented information, of our 2023 Consolidated financial statements for an allocation of segmented earnings by business segment.

Our asset mix will continue to evolve to align with the North American energy mix. We anticipate the following shifts in capital allocation as the world progresses towards a low-carbon future while balancing energy security and affordability needs:

- Natural Gas Pipelines will continue to attract capital driven by coal to gas conversion and LNG exports
- Power and Energy Solutions weighting in our portfolio is expected to gradually grow over time, heavily weighted to nuclear and pumped hydro. Measured investment in emerging technologies will develop capabilities that are complementary to our core businesses, without taking significant commodity price, volumetric or technology risk
- The separation of the Liquids Pipelines business will allow it to pursue growth opportunities to capture incremental value.

Key components of our strategy

1 Maximize the full-life value of our infrastructure assets and commercial positions

- Maintaining safe, reliable operations and ensuring asset integrity, while minimizing environmental impacts, continues to be the foundation of our business
- Our pipeline assets include large-scale natural gas and crude oil pipelines and associated storage facilities that connect long-life, low cost supply basins with premium North American and export markets, generating 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.

2 Commercially develop and build new asset investment programs

- We are developing high quality, long-life assets under our current capital program, comprised of approximately $31 billion in secured projects, largely underpinned by long-term contracts or commercial rate regulation. We expect that these investments will contribute to incremental earnings and cash flows as they are placed in service
- Our extensive asset footprint offers significant in-corridor growth opportunities that support our current incumbent positions in natural gas, liquids and nuclear energy. This also includes possible future opportunities to deploy lower GHG emission infrastructure technologies such as pumped hydro, hydrogen and carbon capture, which will help reduce our GHG emissions footprint and that of our customers, while supporting longevity of our existing assets
- We strive to develop projects and manage construction risk in a disciplined manner that maximizes capital efficiency and returns to shareholders
- As part of our growth strategy, we rely on our experience and our policy, regulatory, commercial, financial, legal and operational expertise to successfully permit, fund, build and integrate new pipeline and other energy facilities
- Safety, executability, profitability and responsible sustainability performance are fundamental to our investments.

3 Cultivate a focused portfolio of high-quality development and investment options

- We assess opportunities to develop and acquire energy infrastructure that complements our existing portfolio, protects and grows our franchise businesses, enhances future resilience under a changing energy mix, and diversifies access to attractive supply and market regions within our risk preferences. Refer to the Risk oversight and enterprise risk management section for an overview of our enterprise risks
- We focus on commercially rate-regulated and/or long-term contracted growth initiatives in core regions of North America and prudently manage development costs, minimizing capital at risk in a project's early stages
- We will advance selected opportunities, including lower carbon growth initiatives in emerging sub-sectors where we are likely to build a strong competitive position in the future, to full development and construction when market conditions are appropriate, technology is proven, and project risks and returns are known and acceptable
- 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 contribute to our resilience, strengthen our asset base or improve diversification.

4 Maximize our competitive strengths

- We continually seek to enhance our core competencies in safety, operational excellence, investment opportunity origination, project execution and stakeholder relations, as well as key sustainability areas to ensure we deliver shareholder value
- The use of a disciplined approach to capital allocation supports our ability to maximize value over the short, medium and long term while protecting and growing our incumbencies. We allocate capital in a manner that improves the breadth and cost competitiveness of the services we provide, extends the life of our assets, increases diversification and strengthens the carbon-competitiveness of our assets
- We believe that our high-quality, diversified portfolio of incumbent assets results in predictable, low risk cash flows and positions us well to succeed under any energy transition scenario and across all economic cycles
- A strong focus on talent management ensures that we have the necessary capabilities to execute and deliver on our strategy.

Our competitive advantage

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 deliver the energy people need today and in the future. We will do this safely, responsibly, collaboratively and with integrity 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 and franchises 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. We have five incumbent franchise businesses – transporting natural gas from the WCSB; transporting natural gas from the Appalachian basin; importing natural gas into Mexico; exporting crude oil to the U.S. Midwest and Gulf Coast markets; and our nuclear business in Ontario through Bruce Power. These 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 low-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 operational excellence and a commitment to health, safety, sustainability and the environment 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 sizable amounts of competitively priced capital to support new investments while preserving financial flexibility, including asset divestitures, to fund our operations in all market conditions. We deliver a balance of dividend income and growth. In addition, we continue to maintain the simplicity and understandability of our business and corporate structure
- **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, re-purposing the underutilized Canadian Mainline pipeline capacity from natural gas to crude oil service, installing electric compression and/or switching gas compression to electrification such as the Valhalla North and Berland River (VNBR) and WR projects in Canada and the U.S., respectively, and currently assessing development of grid-scale, flexible and clean energy storage through the proposed Ontario Pumped Storage Project
- **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 on sustainability-related topics with all stakeholders. We publish our GHG emissions intensity on a corporate-wide basis in our annual Report on Sustainability, and in 2023, we issued reports on the Reliability of Methane Emissions Disclosure and Climate-related Lobbying to provide more transparency and insight into our climate-related goals and efforts. We continue to assess our emission reduction targets and major components of our longer-term reduction plan against various criteria, including policy, regulatory, commercial and economic developments, the outcomes of our capital rotation program and the proposed spin-off of our Liquids Pipelines business. Aligned with our Commitment Statement and integrated throughout our 2023 Report on Sustainability, our refreshed sustainability commitments reflect the material topics most relevant to our business and our stakeholders. We continue to focus on our nine sustainability commitments, and associated metrics and targets, including positioning to achieve net zero emissions from our operations by 2050, 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.

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 asset divestitures 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 capabilities 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.

2023 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, comparable earnings per common share and comparable funds generated from operations are all non-GAAP measures. Refer to page 11 for more information about the non-GAAP measures we use and pages 23 and 88, as well as the Financial results section in each business segment for reconciliations to the most directly comparable GAAP measures.

year ended December 31 (millions of $, except per share amounts)	2023	2022	2021
Income			
Revenues	**15,934**	14,977	13,387
Net income (loss) attributable to common shares	**2,829**	641	1,815
per common share – basic	**$2.75**	$0.64	$1.87
Comparable EBITDA[1]	**10,988**	9,901	9,368
Comparable earnings	**4,652**	4,279	4,142
per common share	**$4.52**	$4.30	$4.26
Cash flows			
Net cash provided by operations	**7,268**	6,375	6,890
Comparable funds generated from operations	**7,980**	7,353	7,406
Capital spending[2]	**12,298**	8,961	7,134
Acquisitions, net of cash acquired	**(307)**	—	—
Proceeds from sales of assets, net of transaction costs	**33**	—	35
Disposition of equity interest, net of transaction costs[3]	**5,328**	—	—
Balance sheet[4]			
Total assets	**125,034**	114,348	104,218
Long-term debt, including current portion	**52,914**	41,543	38,661
Junior subordinated notes	**10,287**	10,495	8,939
Preferred shares	**2,499**	2,499	3,487
Non-controlling interests	**9,455**	126	125
Common shareholders' equity	**27,054**	31,491	29,784
Dividends declared			
per common share	**$3.72**	$3.60	$3.48
Basic common shares (millions)			
– weighted average for the year	**1,030**	995	973
– issued and outstanding at end of year	**1,037**	1,018	981

1 Additional information on Segmented earnings (losses), the most directly comparable GAAP measure, can be found on page 11.

2 Capital spending reflects cash flows associated with our Capital expenditures, Capital projects in development and Contributions to equity investments. Refer to Note 5, Segmented information, of our 2023 Consolidated financial statements for the financial statement line items that comprise total capital spending.

3 Included in the Financing activities section of the Consolidated statement of cash flows.

4 At December 31.

Consolidated results

year ended December 31 (millions of $, except per share amounts)	2023	2022	2021
Canadian Natural Gas Pipelines	**(90)**	(1,440)	1,449
U.S. Natural Gas Pipelines	**3,531**	2,617	3,071
Mexico Natural Gas Pipelines	**796**	491	557
Liquids Pipelines	**1,011**	1,123	(1,600)
Power and Energy Solutions	**1,004**	833	628
Corporate	**(116)**	8	(46)
Total segmented earnings (losses)	**6,136**	3,632	4,059
Interest expense	**(3,263)**	(2,588)	(2,360)
Allowance for funds used during construction	**575**	369	267
Foreign exchange gains (losses), net	**320**	(185)	10
Interest income and other	**242**	146	190
Income (loss) before income taxes	**4,010**	1,374	2,166
Income tax (expense) recovery	**(942)**	(589)	(120)
Net income (loss)	**3,068**	785	2,046
Net (income) loss attributable to non-controlling interests	**(146)**	(37)	(91)
Net income (loss) attributable to controlling interests	**2,922**	748	1,955
Preferred share dividends	**(93)**	(107)	(140)
Net income (loss) attributable to common shares	**2,829**	641	1,815
Net income (loss) per common share – basic	**$2.75**	$0.64	$1.87

Net income attributable to common shares in 2023 was $2.8 billion or $2.75 per share (2022 – $0.6 billion or $0.64 per share; 2021 – $1.8 billion or $1.87 per share), an increase of $2.2 billion or $2.11 per share compared to 2022. The significant increase for the year ended December 31, 2023 compared to 2022, as well as the significant decrease in Net income attributable to common shares of $1.2 billion or $1.23 per share in 2022 compared to 2021 are primarily due to the net effect of specific items mentioned below. Net income per common share in all years also reflects the impact of common shares issued, including common shares issued for the acquisition of TC PipeLines, LP in first quarter 2021.

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

2023

- an after-tax impairment charge of $1.9 billion related to our equity investment in Coastal GasLink Pipeline Limited Partnership (Coastal GasLink LP). Refer to Note 8, Coastal GasLink, of our 2023 Consolidated financial statements for additional information
- a $52 million after-tax 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 and included accrued pre-tax carrying charges of $10 million
- a $48 million after-tax expense related to Focus Project costs. Refer to the Corporate – Significant events section for additional information
- an after-tax unrealized foreign exchange loss of $44 million on the peso-denominated intercompany loan between TCPL and TGNH
- a $36 million after-tax accrued insurance expense related to the Milepost 14 incident. Refer to the Liquids Pipelines – Significant events section for additional information
- an after-tax charge of $34 million due to Liquids Pipelines business separation costs related to the spinoff Transaction. Refer to the Liquids Pipelines – Significant events section for additional information

- preservation and other costs for Keystone XL pipeline project assets of $14 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $55 million after-tax recovery on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico
- an $18 million after-tax recovery 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

- an after-tax impairment charge of $2.6 billion related to our equity investment in Coastal GasLink LP
- an after-tax goodwill impairment charge of $531 million related to Great Lakes
- a $196 million income tax expense for the settlement related to prior years' income tax assessments in Mexico
- $114 million after-tax expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico
- $20 million after-tax charge due to the CER decision on Keystone issued in December 2022 in respect of a tolling-related complaint pertaining to amounts reflected in 2021 and 2020
- preservation and other costs for Keystone XL pipeline project assets of $19 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $5 million after-tax expense 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.

2021

- a $2.1 billion after-tax asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, related to the termination of the Keystone XL pipeline project following the January 2021 revocation of the Presidential Permit
- a $48 million after-tax expense with respect to transition payments incurred as part of the Voluntary Retirement Program (VRP)
- preservation and other costs for Keystone XL pipeline project assets of $37 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge, as well as interest expense on the Keystone XL project-level credit facility prior to its termination
- an after-tax gain of $19 million related to the sale of the remaining 15 per cent interest in Northern Courier
- a $7 million after-tax recovery primarily related to certain costs from the IESO associated with the Ontario natural gas-fired power plants sold in April 2020.

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

Net income in all years included unrealized gains and losses on our proportionate share of Bruce Power's fair value adjustment on funds invested for post-retirement benefits and derivatives related to its risk management activities, as well as unrealized gains and losses from changes in our risk management activities, all of which we exclude along with the above noted items, to arrive at comparable earnings. A reconciliation of Net income (loss) attributable to common shares to comparable earnings is shown in the following table.

Reconciliation of net income (loss) attributable to common shares to comparable earnings

year ended December 31 (millions of $, except per share amounts)	2023	2022	2021
Net income (loss) attributable to common shares	**2,829**	641	1,815
Specific items (net of tax):			
Coastal GasLink impairment charge	**1,943**	2,643	—
Keystone regulatory decisions	**52**	20	—
Focus Project costs	**48**	—	—
Foreign exchange (gains) losses, net – intercompany loan	**44**	—	—
Milepost 14 insurance expense	**36**	—	—
Liquids Pipelines business separation costs	**34**	—	—
Keystone XL preservation and other	**14**	19	37
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**(55)**	114	—
Keystone XL asset impairment charge and other	**(18)**	5	2,134
Great Lakes goodwill impairment charge	**—**	531	—
Settlement of Mexico prior years' income tax assessments	**—**	196	—
Voluntary Retirement Program	**—**	—	48
Gain on sale of Northern Courier	**—**	—	(19)
Gain on sale of Ontario natural gas-fired power plants	**—**	—	(7)
Bruce Power unrealized fair value adjustments	**(5)**	13	(11)
Risk management activities[1]	**(270)**	97	145
Comparable earnings	**4,652**	4,279	4,142
Net income (loss) per common share	**$2.75**	$0.64	$1.87
Coastal GasLink impairment charge	**1.89**	2.66	—
Keystone regulatory decisions	**0.05**	0.02	—
Focus Project costs	**0.05**	—	—
Foreign exchange (gains) losses, net – intercompany loan	**0.04**	—	—
Milepost 14 insurance expense	**0.03**	—	—
Liquids Pipelines business separation costs	**0.03**	—	—
Keystone XL preservation and other	**0.01**	0.02	0.04
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**(0.05)**	0.11	—
Keystone XL asset impairment charge and other	**(0.02)**	0.01	2.19
Great Lakes goodwill impairment charge	**—**	0.53	—
Settlement of Mexico prior years' income tax assessments	**—**	0.20	—
Voluntary Retirement Program	**—**	—	0.05
Gain on sale of Northern Courier	**—**	—	(0.02)
Gain on sale of Ontario natural gas-fired power plants	**—**	—	(0.01)
Bruce Power unrealized fair value adjustments	**—**	0.01	(0.01)
Risk management activities	**(0.26)**	0.10	0.15
Comparable earnings per common share	**$4.52**	$4.30	$4.26

1	year ended December 31 (millions of $)	2023	2022	2021
	U.S. Natural Gas Pipelines	**80**	(15)	6
	Liquids Pipelines	**(34)**	20	(3)
	Canadian Power	**(31)**	4	12
	U.S. Power	**9**	—	—
	Natural Gas Storage	**91**	11	(6)
	Foreign exchange	**246**	(149)	(203)
	Income tax attributable to risk management activities	**(91)**	32	49
	Total unrealized gains (losses) from risk management activities	**270**	(97)	(145)

Comparable EBITDA to comparable earnings

Comparable EBITDA represents segmented earnings (losses) 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)	2023	2022	2021
Comparable EBITDA			
Canadian Natural Gas Pipelines	**3,335**	2,806	2,675
U.S. Natural Gas Pipelines	**4,385**	4,089	3,856
Mexico Natural Gas Pipelines	**805**	753	666
Liquids Pipelines	**1,457**	1,366	1,526
Power and Energy Solutions	**1,020**	907	669
Corporate	**(14)**	(20)	(24)
Comparable EBITDA	**10,988**	9,901	9,368
Depreciation and amortization	**(2,778)**	(2,584)	(2,522)
Interest expense included in comparable earnings	**(3,253)**	(2,588)	(2,354)
Allowance for funds used during construction	**575**	369	267
Foreign exchange gains (losses), net included in comparable earnings	**118**	(8)	254
Interest income and other included in comparable earnings	**278**	146	190
Income tax (expense) recovery included in comparable earnings	**(1,037)**	(813)	(830)
Net (income) loss attributable to non-controlling interests	**(146)**	(37)	(91)
Preferred share dividends	**(93)**	(107)	(140)
Comparable earnings	**4,652**	4,279	4,142
Comparable earnings per common share	**$4.52**	$4.30	$4.26

Comparable EBITDA – 2023 versus 2022

Comparable EBITDA in 2023 increased by $1,087 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
- increased EBITDA from Liquids Pipelines due to higher volumes on the Keystone Pipeline System and the foreign exchange impact of a stronger U.S. dollar on the translation of our U.S. dollar-denominated operations
- 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 84, U.S. dollar-denominated comparable EBITDA increased by US$142 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.

Comparable EBITDA – 2022 versus 2021

Comparable EBITDA in 2022 increased by $533 million compared to 2021 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 a higher contract price, higher realized power prices and increased contributions from Natural Gas Storage and Other as a result of higher realized spreads in 2022
- higher U.S. dollar-denominated EBITDA from U.S. Natural Gas Pipelines largely due to incremental earnings from growth projects placed in service, higher commodity prices from our mineral rights business, as well as increased net earnings from Columbia Gas primarily due to an increase in transportation rates effective February 2021
- increased EBITDA from Canadian Natural Gas Pipelines largely attributable to the impact of higher flow-through costs and increased rate-base earnings on the NGTL System; and lower flow-through costs, partially offset by higher incentive earnings on Canadian Mainline
- higher 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
- decreased EBITDA from Liquids Pipelines as a result of lower rates and contracted volumes on the U.S. Gulf Coast section of the Keystone Pipeline System, as well as reduced contributions from liquids marketing activities and the foreign exchange impact of a stronger U.S. dollar on the translation of our U.S. dollar-denominated operations
- 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 84, U.S. dollar-denominated comparable EBITDA decreased by US$63 million compared to 2021; however, this was translated to Canadian dollars at an average rate of 1.30 in 2022 versus 1.25 in 2021. 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 – 2023 versus 2022

Comparable earnings in 2023 were $373 million or $0.22 per common share higher than in 2022, and were primarily the net result of:

- changes in comparable EBITDA described above
- 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
- increased income tax expense due to the impact of higher comparable earnings subject to income tax, Mexico foreign exchange exposure, lower foreign tax rate differentials, partially offset by lower flow-through income taxes and lower Mexico inflation adjustments
- higher depreciation and amortization reflecting expansion facilities and new projects placed in service and the acquisitions of the Fluvanna Wind Farm and Blue Cloud Wind Farm (Texas Wind Farms), partially offset by the discontinuance of depreciation expense on TGNH assets in Mexico accounted for as leases
- 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) and the acquisition of the Texas Wind Farms
- 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
- higher interest income and other due to higher interest earned on short-term investments
- the impact of activities to manage our foreign exchange exposure to net liabilities in Mexico, partially offset by derivatives used to manage our net exposure to foreign exchange rate fluctuation on U.S. dollar-denominated income and the revaluation of our peso-denominated net monetary liabilities to U.S. dollars.

Comparable earnings – 2022 versus 2021

Comparable earnings in 2022 were $137 million or $0.04 per common share higher than in 2021, and were primarily the net result of:

- changes in comparable EBITDA described above
- the impact of derivatives used to manage our net exposure to foreign exchange rate fluctuation on U.S. dollar-denominated income and the revaluation of our peso-denominated net monetary liabilities to U.S. dollars, partially offset by activities to manage our foreign exchange exposure to net liabilities in Mexico
- increased interest expense primarily due to higher interest rates on increased levels of short-term borrowings, long-term debt and junior subordinated note issuances, net of maturities, as well as the foreign exchange impact of a stronger U.S. dollar in 2022
- lower interest income and other due to the repayment of the inter-affiliate loan receivable by the Sur de Texas joint venture on July 29, 2022
- higher AFUDC predominantly due to the reactivation of AFUDC on the TGNH assets under construction, partially offset by the impact of decreased capital expenditures and projects placed in service
- higher depreciation and amortization reflecting new assets placed in service and a stronger U.S. dollar in 2022
- lower Net income attributable to non-controlling interests following the March 2021 acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy
- decreased Income tax expense primarily due to lower flow-through income taxes and higher foreign tax rate differentials, partially offset by higher earnings subject to tax and other various valuation allowances
- lower Preferred share dividends due to the redemption of preferred shares in 2022 and 2021.

Comparable earnings per common share reflect the dilutive effect of common shares issued in 2023 and 2022 and the impact of common shares issued for the acquisition of the remaining ownership interests in TC PipeLines, LP in March 2021. Refer to the Financial Condition section for additional information.

Cash flows

Net cash provided by operations of $7.3 billion in 2023 was 14 per cent higher than 2022 primarily due to the amount and timing of working capital changes and higher funds generated from operations. Comparable funds generated from operations of $8.0 billion in 2023 were nine per cent higher than 2022 primarily due to higher comparable earnings and increased distributions from operating activities of our equity investments.

Funds used in investing activities

Capital spending[1]

year ended December 31 (millions of $)	2023	2022	2021
Canadian Natural Gas Pipelines	**6,184**	4,719	2,737
U.S. Natural Gas Pipelines	**2,660**	2,137	2,820
Mexico Natural Gas Pipelines	**2,292**	1,027	129
Liquids Pipelines	**49**	143	571
Power and Energy Solutions	**1,080**	894	842
Corporate	**33**	41	35
	12,298	8,961	7,134

1 Capital spending reflects cash flows associated with our Capital expenditures, Capital projects in development and Contributions to equity investments. Refer to Note 5, Segmented information, of our 2023 Consolidated financial statements for the financial statement line items that comprise total capital spending.

In 2023 and 2022, we invested $12.3 billion and $9.0 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 2023 and 2022 included contributions of $4.1 billion and $2.2 billion, respectively, to our equity investments, predominantly related to Coastal GasLink LP and Bruce Power.

Acquisitions

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

Proceeds from sales of assets

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 US$25 million.

In 2021, we completed the sale of our remaining 15 per cent equity interest in Northern Courier for gross proceeds of $35 million.

Balance sheet

We continue to maintain a solid financial position while growing our total assets by $10.7 billion in 2023. At December 31, 2023, common shareholders' equity and non-controlling interests, represented 37 per cent (2022 – 35 per cent) of our capital structure, while other subordinated capital, in the form of junior subordinated notes and preferred shares, represented an additional 13 per cent (2022 – 14 per cent). Refer to the Financial Condition section for additional information.

Dividends

We increased the quarterly dividend on our outstanding common shares by 3.2 per cent to $0.96 per common share for the quarter ending March 31, 2024, which equates to an annual dividend of $3.84 per common share. This was the twenty-fourth 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. The participation rate by common shareholders in the DRP in 2023 was approximately 39 per cent (2022 – 33 per cent), resulting in $737 million (2022 – $607 million) reinvested in common equity under the program.

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 $)	2023	2022	2021
Common shares	**2,787**	3,192	3,317
Preferred shares	**92**	106	141

OUTLOOK

Comparable EBITDA and comparable earnings

Our 2024 comparable EBITDA and comparable earnings per common share outlooks do not take into consideration the impact of the spinoff Transaction as it is subject to TC Energy shareholder approval, court approval, favourable tax rulings, other regulatory approvals and satisfaction of other customary closing conditions.

We expect our 2024 comparable EBITDA to be higher than 2023 primarily due to the following:

- growth in the NGTL System from advancement of expansion programs
- full-year impact of Bruce Power Unit 6 return to service in September 2023
- new projects anticipated to be placed in service in 2024, along with the full-year impact of projects placed in service in 2023.

Our 2024 comparable earnings per common share is expected to be lower than 2023 due to the net impact of the following:

- higher net income attributable to non-controlling interests as a result of the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf in 2023
- increase in comparable EBITDA described above
- higher AFUDC related to the Southeast Gateway pipeline.

We continue to monitor developments in energy markets, our construction projects, regulatory proceedings and our asset divestiture program for any potential impacts on the above outlooks.

Consolidated capital expenditures

In 2023, we incurred approximately $12.4 billion in capital expenditures on our secured capital program and projects under development. Prior to adjustments for non-controlling interests, we expect to incur gross capital expenditures, including capitalized interest, of approximately $8.5 to $9.0 billion in 2024 on growth projects, maintenance capital expenditures, contributions to equity investments and projects under development. We anticipate our net capital expenditures in 2024 to be approximately $8.0 to $8.5 billion after considering capital expenditures attributable to the non-controlling interests of entities we control.

The majority of our 2024 capital program is expected to be focused on the advancement of secured projects including the Southeast Gateway pipeline, U.S. Natural Gas Pipelines projects, the Coastal GasLink pipeline project, Bruce Power Major Component Replacement (MCR) programs and normal course maintenance capital expenditures.

Refer to the Outlook section in each business segment for additional details on expected earnings and capital expenditures for 2024.

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 significant growth in earnings and cash flows. In addition, many of these projects are expected to advance our goals to reduce our own carbon footprint, as well as that of our customers.

Our capital program consists of approximately $31 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. Tolling arrangements in our Liquids Pipelines business provide for the recovery of maintenance capital expenditures.

During 2023, we placed approximately $5.3 billion of projects in service, which included natural gas pipeline capacity capital projects along our extensive North American asset footprint, as well as the Bruce Power Unit 6 MCR, which was declared commercially operational on September 14, 2023. In addition, approximately $2.2 billion of maintenance and modernization capital expenditures were incurred.

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, primarily Coastal GasLink and Bruce Power.

(billions of $)	Expected in-service date	Estimated project cost	Project costs incurred at December 31, 2023
Canadian Natural Gas Pipelines			
NGTL System	2024	0.7	0.5
	2026+	0.7	0.1
Coastal GasLink[1]	2024	5.5	4.6
Regulated maintenance capital expenditures	2024-2026	2.3	—
U.S. Natural Gas Pipelines			
Modernization and other[2]	2024-2026	US 1.7	US 0.9
Delivery market projects	2025	US 1.5	US 0.2
Heartland project	2027	US 0.9	—
Other capital	2024-2028	US 1.5	US 0.5
Regulated maintenance capital expenditures	2024-2026	US 2.2	—
Mexico Natural Gas Pipelines			
Villa de Reyes – south section[3]	2024	US 0.3	US 0.3
Tula[4]	—	US 0.4	US 0.3
Southeast Gateway	2025	US 4.5	US 2.4
Liquids Pipelines			
Recoverable maintenance capital expenditures	2024-2026	0.3	—
Power and Energy Solutions			
Bruce Power – Unit 3 MCR	2026	1.1	0.6
Bruce Power – Unit 4 MCR	2028	0.9	0.1
Bruce Power – life extension[5]	2024-2027	1.8	0.7
Other			
Non-recoverable maintenance capital expenditures[6]	2024-2026	0.4	—
		26.7	11.2
Foreign exchange impact on secured projects[7]		4.2	1.5
Total secured projects (Cdn$)		30.9	12.7

1 The estimated project cost noted above represents our share of anticipated partner equity contributions to the project. Mechanical completion was achieved in November 2023. Commercial in-service of the Coastal GasLink pipeline will occur after completion of plant commissioning activities at the LNG Canada facility and upon receiving notice from LNG Canada. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information.

2 Includes 100 per cent of the capital expenditures related to our modernization program on Columbia Gas, as well as certain large-scope maintenance projects across our U.S. natural gas pipelines footprint due to their discrete nature and timing for regulatory recovery. Refer to the U.S. Natural Gas Pipelines – Significant events section for additional information.

3 We are working with the CFE on completing the remaining section of the Villa de Reyes pipeline, with an anticipated commercial in-service date in the second half of 2024. 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 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 comprised of our proportionate share of maintenance capital expenditures for Bruce Power and other assets.

7 Reflects U.S./Canada foreign exchange rate of 1.32 at December 31, 2023.

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. While each business segment also has additional areas of focus for further ongoing business development activities and growth opportunities, new opportunities will be assessed within our capital allocation framework in order to fit within our annual capital expenditure parameters. As these projects advance and reach necessary 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 in-corridor expansions, providing connectivity to LNG export terminals, connections to growing shale gas supplies and other opportunities supporting our reduction in GHG emissions intensity.

U.S. Natural Gas Pipelines

Delivery Market Projects

Projects are in development that are expected to replace, upgrade and expand certain U.S. Natural Gas Pipelines facilities while reducing emissions along portions of our pipeline systems in principal delivery markets. The enhanced facilities are expected to improve reliability of our systems and allow for additional transportation services under long-term contracts to address growing demand in the U.S. Midwest and the Mid-Atlantic regions, while reducing direct GHG emissions.

Other Opportunities

We are currently pursuing a variety of projects, including compression replacement, while furthering the electrification of our fleet, power generation and LDCs, expanding our modernization programs and in-corridor expansion opportunities on our existing systems. These projects are expected to improve the reliability of our systems with a focus on cleaner energy.

We are actively developing RNG transportation hubs within our U.S. Natural Gas Pipelines footprint. These hubs are designed to provide centralized access to existing energy transportation infrastructure for RNG sources, such as farms, wastewater treatment facilities and landfills. We believe that the development of these hubs is an important step towards the acceleration of methane capture projects and the concurrent reduction of GHG emissions.

We are also developing multiple transmission projects to link gas supply to the facilities that will serve the growing global demand for North American LNG.

Mexico Natural Gas Pipelines

On August 4, 2022, we announced a strategic alliance with the CFE, Mexico's state-owned electric utility, to accelerate the development of natural gas infrastructure in the central and southeast regions of Mexico.

Liquids Pipelines

We remain focused on maximizing the value of our liquids assets by finding solutions to enable flexible and tailored solutions for our customers. We continue to seek ways of optimizing our existing assets by extending connectivity between supply and delivery markets. We are pursuing selective growth opportunities to add incremental value to our business and expansions that leverage latent capacity on our existing infrastructure. We remain disciplined in our approach and will position our business development activities strategically to capture opportunities within our risk preferences.

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 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. We expect to spend approximately $4.0 billion for our proportionate share of the Bruce Power MCR program costs for Units 5, 7 and 8 and the remaining Asset Management program costs beyond 2027, as well as the incremental uprate initiative discussed below.

Uprate Initiative

Bruce Power's Project 2030 has a goal of achieving a site peak output of 7,000 MW by 2033 in support of 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 the site peak output. Project 2030 is arranged in three stages with the first two stages fully approved for execution. Stage 1 started in 2019 and is expected to add 150 MW of output and Stage 2, which began in early 2022, is targeting another 200 MW.

Ontario Pumped Storage

Along with the Saugeen Ojibway Nation, our prospective partner, we continue to advance the Ontario Pumped Storage Project (OPSP), an energy storage facility located near Meaford, Ontario designed to provide 1,000 MW of flexible, clean energy to Ontario's electricity system using a process known as pumped hydro storage. Next steps to advance the OPSP include:

- working with the Ministry of Energy (Ministry) and Ontario Energy Board on the establishment of a potential long-term revenue framework by July 2024
- providing a breakdown of estimated development costs and schedule to the Ministry after which the Ministry will provide a recommendation to proceed with pre-development work within 45 days
- negotiation of cost recovery agreement with the IESO to recover eligible, prudently incurred expenses associated with pre-development work. A follow up report from the IESO to the Ministry to be provided within 60 days of estimates submission
- provide further information to assist with the Ontario government's assessment of OPSP societal and economic benefits.

A final decision to fund development costs of OPSP is subject to Cabinet approvals and Ministerial directive to the IESO to execute agreements with us.

Once in service, this project would store emission-free energy when available and provide that energy to Ontario during periods of peak demand, thereby maximizing the value of existing emission-free generation in the province.

The OPSP remains subject to approval by our Board of Directors and the Saugeen Ojibway Nation. Construction would begin in the latter part of this decade with in-service in the early 2030s, subject to receipt of regulatory and corporate approvals.

Canyon Creek Pumped Storage

We are utilizing the existing site infrastructure from a decommissioned coal mine, located near Hinton, Alberta, to develop a pumped hydro storage project that is expected to have a generating capacity of 75 MW. The facility is expected to provide up to 37 hours of on-demand, flexible, clean energy and ancillary services to the Alberta electricity grid. The project has received the approval of the Alberta Utilities Commission and the required approval of the Government of Alberta for hydro projects under the Dunvegan Hydro Development Act (Alberta).

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.

Other Carbon Capture

We are collaborating with Minnkota Power Cooperative (Minnkota), Mitsubishi Heavy Industries and Kiewit on Project Tundra, a next-generation technology carbon capture and storage project. Project Tundra would be our first carbon capture and sequestration project in the U.S., capturing up to approximately four million tons of CO_2 per annum from Minnkota's Milton R. Young Generating Station. When constructed, Project Tundra is expected to be the largest post-combustion carbon capture project in North America and would support the continuation of baseload, reliable, power generation in the region. In December 2023, the U.S. Department of Energy and Office for Clean Energy Demonstrations announced up to US$350 million in funding for Project Tundra.

Hydrogen Hubs

We are advancing multiple hydrogen production opportunities to potentially serve long-haul transportation, power generation, large industrials and heating customers across the U.S. and Canada. We believe that measured investment in emerging technologies like hydrogen will help us expand our capabilities through energy transition, focusing on opportunities that complement our core business and where we can obtain favourable and strategically-consistent commercial arrangements such as rate regulation and/or long-term contracts.

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 25 per cent of continental daily natural gas needs through:

- wholly-owned natural gas pipelines – 64,207 km (39,896 miles)
- partially-owned natural gas pipelines – 29,372 km (18,251 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 optimize 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
- decarbonizing our energy consumption, thereby reducing overall GHG emissions intensity.

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 enabling energy transition. Natural gas is a reliable, high-efficiency energy source that is displacing coal-fired power while backstopping the intermittency of renewable power sources across North America. In support of our GHG emissions intensity reduction target, we continue to improve operational efficiencies and factor sustainability 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 and other stakeholders in alignment with our values and sustainability commitments.

Recent highlights

Canadian Natural Gas Pipelines

- approximately $2.8 billion of capital projects placed in service in 2023 primarily related to the NGTL System and NGTL System/Foothills West Path expansions, as well as spending on maintenance capital
- mechanical completion of the Coastal GasLink pipeline project in fourth quarter 2023
- CER approved the VNBR project in fourth quarter 2023
- achieved record throughput volumes on the NGTL System and Canadian Mainline.

U.S. Natural Gas Pipelines

- placed approximately US$1.6 billion of capital projects in service in 2023, including the North Baja XPress project, as well as spending on modernization and maintenance capital
- sanctioned an additional US$1.6 billion of capital projects including the Heartland project on ANR and the Bison XPress project on Northern Border
- sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf for proceeds of $5.3 billion (US$3.9 billion), which closed on October 4, 2023
- ANR, Columbia Gulf and Tuscarora rate case settlements approved by FERC
- 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 began construction on all facilities and installations in Veracruz and Tabasco, as well as offshore pipe laying at the end of 2023
- the lateral section of the Villa de Reyes pipeline was placed in commercial service in third quarter 2023
- in December 2023, TGNH and the CFE obtained from Mexico's Federal Economic Competition Commission (COFECE) a favourable merger ruling and a determination that the proposed minority CFE equity participation in TGNH did not require a favourable cross participation opinion given that the CFE would not have a controlling interest in TGNH. TGNH and the CFE subsequently requested the CRE to confirm that a cross participation permit is not required given that the CFE would not have a controlling interest in TGNH
- 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 39 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 conversion from coal, 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 the U.S. markets including Great Lakes, Midwest, Gulf Coast and U.S. Northeast from the WCSB and, through interconnects, from the Appalachian basin.

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 own a 60 per cent equity 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 own a 60 per cent equity interest and are the operator of this pipeline.

Other U.S. Natural Gas Pipelines: We have ownership interests in ten 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 2023 supplied approximately 17 per cent of Mexico's total natural gas imports via pipelines. We own 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 existing Tamazunchale pipeline, 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 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.

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, FERC in the U.S. and the CRE in Mexico. 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 135 Bcf/d by 2027, reflecting an increase of approximately 28 Bcf/d from 2022 levels.

As the world shifts toward lower GHG emission-intensive fuel sources, we believe that further retirements of coal-fired power generation and 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 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
- 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 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 the addition of 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

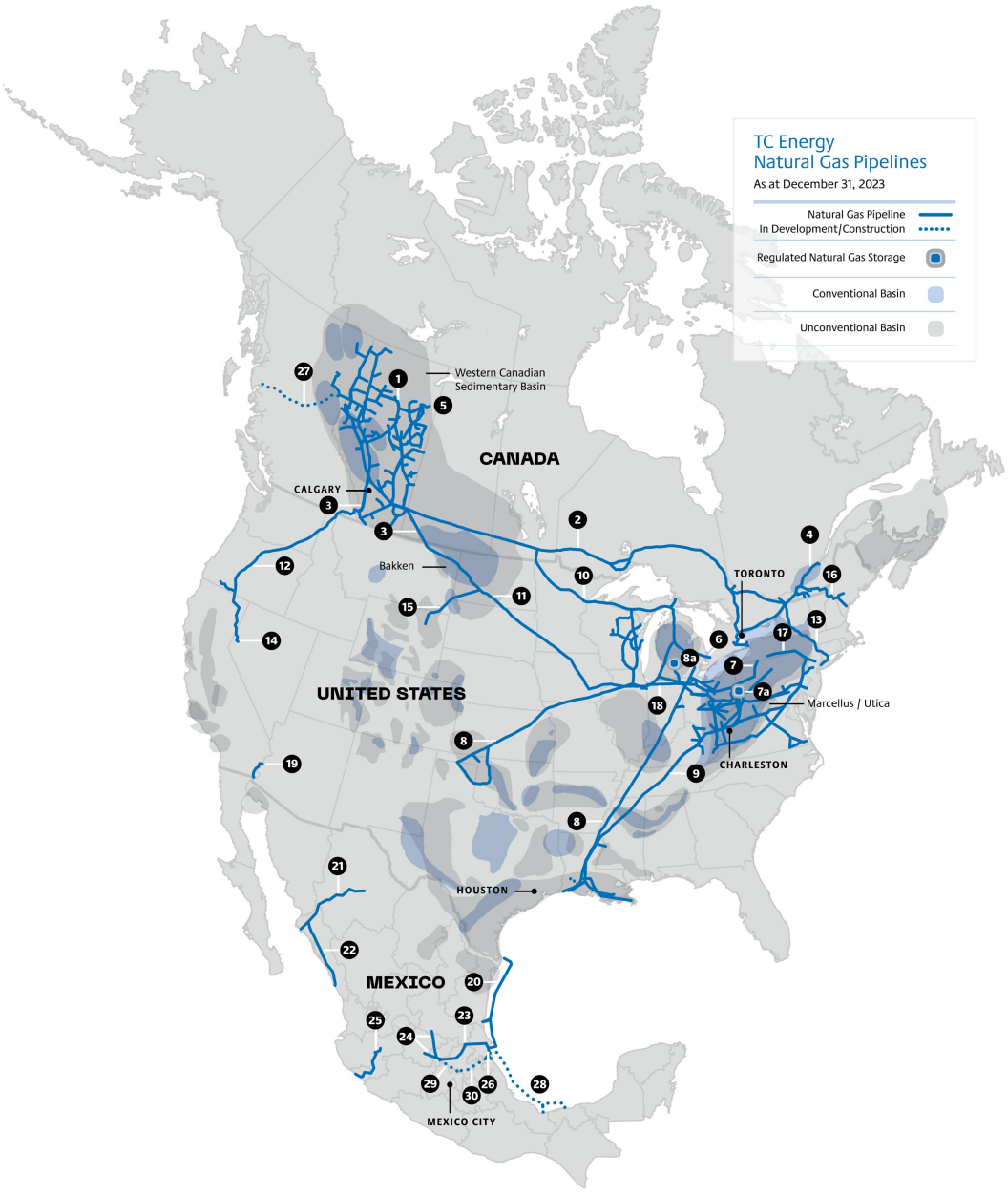
Changes in supply and demand levels and locations have resulted in increased competition to provide transportation services throughout North America. Our well-distributed footprint of natural gas pipelines, particularly in the liquids-rich and low-cost WCSB and the Appalachian basin, both of which are 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, including GHG emissions intensity reduction.

In 2024, we will continue to focus on the execution of our existing capital program that includes progressing construction on our Southeast Gateway pipeline in Mexico, investment in the NGTL System, as well as the completion and initiation of new pipeline projects in the United States. We will remain focused on capital discipline as we continue to pursue the next wave of growth opportunities. 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.

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, 2023
Natural Gas Pipeline
In Development/Construction
Regulated Natural Gas Storage
Conventional Basin
Unconventional Basin
Western Canadian Sedimentary Basin
CANADA
CALGARY
Bakken
UNITED STATES
TORONTO
Marcellus / Utica
CHARLESTON
HOUSTON
MEXICO
MEXICO CITY

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	24,386 km (15,153 miles)	Receives, transports and delivers natural gas within Alberta and British Columbia, and connects with Canadian Mainline, Foothills and third-party pipelines.	100 %
2	Canadian Mainline	14,082 km (8,750 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	1,284 km (798 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	Trans Québec & Maritimes (TQM)	651 km (405 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 Portland.	50 %
5	Ventures LP	133 km (83 miles)	Transports natural gas to the oil sands region near Fort McMurray, Alberta.	100 %
6	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			
7	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 %
7a	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
8	ANR[3]	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 %
8a	ANR Storage	247 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key mid-western markets.	
9	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 %
10	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 %
11	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 %
12	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 %
13	Iroquois	669 km (416 miles)	Connects with the Canadian Mainline and serves markets in New York.	50 %
14	Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to markets in northeastern California and northwestern Nevada.	100 %
15	Bison	488 km (303 miles)	Transports natural gas from the Powder River basin in Wyoming to Northern Border in North Dakota.	100 %
16	Portland	475 km (295 miles)	Connects with TQM near East Hereford, Québec to deliver natural gas to customers in the U.S. Northeast and Canadian Maritimes.	61.7 %

		Length	Description	Ownership
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[3]	138 km (86 miles)	Transports natural gas between Arizona and California and connects with a third-party pipeline on the California/Mexico border.	100 %
	Mexico pipelines			
20	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 %
21	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 %
22	Mazatlán	430 km (267 miles)	Transports natural gas from El Oro to Mazatlán, Sinaloa and connects to the Topolobampo pipeline at El Oro.	100 %
23	Tamazunchale	370 km (230 miles)	Transports natural gas from Naranjos, Veracruz to Tamazunchale, San Luis Potosi and on to El Sauz, Querétaro in central Mexico.	100 %
24	Villa de Reyes – north and lateral section	326 km (203 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.	100 %
25	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 %
26	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.	100 %
	Under construction			
	Canadian pipelines			
27	Coastal GasLink	670 km (416 miles)	A greenfield project to deliver natural gas from the Montney gas producing region to LNG Canada's liquefaction facility near Kitimat, British Columbia. Coastal GasLink pipeline was mechanically complete in November 2023 and is ready to deliver gas to the LNG Canada facility. Commercial in-service of the Coastal GasLink pipeline will occur after completion of plant commissioning activities at the LNG Canada facility and upon receiving notice from LNG Canada.	35 %
	NGTL System 2024 Facilities[1]	n/a	Compressor station components of the 2023 NGTL System Intra-Basin Expansion expected to be placed in service in 2024.	100 %
	U.S. pipelines			
	East Lateral XPress[1,3]	n/a	An expansion project on Columbia Gulf through compressor station modifications and additions expected to be placed in service in 2025.	60 %
	Gillis Access Project[2]	68 km (42 miles)	A greenfield pipeline system project that will connect supplies from the Haynesville basin at Gillis, Louisiana to markets elsewhere in Louisiana. The project is expected to be placed in service in 2024.	100 %

	Under construction (continued)	Length	Description	Ownership
	GTN XPress[3]	n/a	An expansion project of GTN through compressor station modifications and additions with the remaining sections expected to be placed in service in 2024.	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.	100 %
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.	100 %
30	Tula[2]	n/a	The pipeline will interconnect the completed east segment with Villa de Reyes near Tula, Hidalgo to supply natural gas to CFE combined-cycle power generating facilities in central Mexico. TC Energy and CFE are assessing options to complete the remaining sections of the pipeline, which are subject to an FID.	100 %
	Permitting and pre-construction phase			
	Canadian pipelines			
	NGTL System 2025+ Facilities[1,2]	50 km (31 miles)	The VNBR project, along with other facilities expected to be placed in service in 2026.	100 %
	U.S. pipelines			
	Bison XPress Project[3]	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
	VR Project[3]	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[3]	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[3]	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 %
	Heartland Project[3]	n/a	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 %

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

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 reached mechanical completion in fourth quarter 2023 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 is operating under a five-year revenue requirement settlement for 2020-2024, which includes an incentive mechanism for certain operating costs and the opportunity to increase depreciation rates if tolls fall below specified levels. The Canadian Mainline is operating under the 2021-2026 Mainline settlement, which includes an incentive to decrease costs and increase revenues.

SIGNIFICANT EVENTS

Coastal GasLink

The 670 km (416 mile) Coastal GasLink pipeline project successfully achieved mechanical completion, completed required commissioning activities and was ready to deliver gas to the LNG Canada facility in fourth quarter 2023. These milestones entitle Coastal GasLink LP to receive a $200 million incentive payment from LNG Canada. In accordance with the contractual terms between the Coastal GasLink LP partners, this amount accrues in full to TC Energy as the project developer and was settled through a cash distribution on February 12, 2024. We recognized the incentive payment as Income (loss) from equity investments in the Consolidated statement of income for the year ended December 31, 2023 and recorded a corresponding amount in Accounts receivable on the Consolidated balance sheet.

Through 2024, Coastal GasLink LP will continue post-construction reclamation activities. Coastal GasLink LP also continues to pursue cost recovery, including certain arbitration proceedings which involve claims by, and the defense of certain claims against, Coastal GasLink LP. These claims have not yet been conclusively determined, but our expectation is that these proceedings are likely to result in cost recoveries. For more information on these proceedings, refer to Note 32, Commitments, contingencies and guarantees, of our 2023 Consolidated financial statements for additional information. The project remains on track with its cost estimate of approximately $14.5 billion.

Commercial in-service of the Coastal GasLink pipeline will occur after completion of plant commissioning activities at the LNG Canada facility and upon receiving notice from LNG Canada. Once in service, the pipeline will transport natural gas from a receipt point in the Dawson Creek area of British Columbia to LNG Canada's natural gas liquefaction facility near Kitimat, British Columbia. Transportation service on the pipeline is underpinned by 25-year TSAs (with renewal provisions) with each of the five LNG Canada participants. We hold a 35 per cent ownership interest in Coastal GasLink LP, the partnership entity that owns the pipeline and that has been contracted to develop, construct and operate the pipeline.

In 2022, Coastal GasLink LP executed definitive agreements with LNG Canada, TC Energy and the other Coastal GasLink LP partners (collectively, the July 2022 agreements) that amended existing project agreements to address and resolve disputes over certain incurred and anticipated costs of the Coastal GasLink pipeline project. Project costs are funded by existing project-level credit facilities and equity contributions from the Coastal GasLink LP partners, including us. Beginning in 2023, the equity financing required to fund construction of the pipeline to completion is initially provided through a subordinated loan agreement between TC Energy and Coastal GasLink LP. Draws by Coastal GasLink LP on this loan will be repaid with funds from equity contributions to the partnership by the Coastal GasLink LP partners, including us, subsequent to the in-service date of the Coastal GasLink pipeline when final project costs are known. We expect that, in accordance with contractual terms, the additional equity contributions required will be predominantly funded by us, except under certain conditions, but will not result in a change to our 35 per cent ownership. At December 31, 2023, committed capacity under this subordinated loan agreement was $3,375 million, on which $2,520 million was drawn.

The expectation that additional equity contributions will predominantly be funded by us was an indicator during the first three quarters of 2023 that a decrease in the value of our equity investment had occurred. As a result, we completed valuation assessments and concluded that there was an other-than-temporary impairment of our investment, resulting in a pre-tax impairment charge on our investment in Coastal GasLink LP of $2,100 million ($1,943 million after tax) for the year ended December 31, 2023. The impairment charge reflected the net impact of changes in the subordinated loan for the nine months ended September 30, 2023, along with TC Energy's proportionate share of unrealized gains and losses on interest rate derivatives in Coastal GasLink LP and other changes to the equity investment. The impairment of the subordinated loan resulted in unrealized non-taxable capital losses that are not recognized. The cumulative pre-tax impairment charge recognized to date at December 31, 2023 is $5,148 million ($4,586 million after tax). Refer to Note 8, Coastal GasLink, of our 2023 Consolidated financial statements for additional information.

At December 31, 2023, the carrying value of our equity investment was $294 million. There was no indicator that there was an other-than-temporary impairment of this investment, and no impairment charge was recognized in fourth quarter 2023.

NGTL System and Foothills

In the year ended December 31, 2023, the NGTL System and Foothills placed approximately $2.0 billion and $0.8 billion, respectively, of capacity projects in service. The details of the significant capacity programs are listed below.

2021 NGTL System Expansion Program

The 2021 NGTL System Expansion Program consists of 344 km (214 miles) of new pipeline, three new compressor units and associated facilities and is expected to add 1.59 PJ/d (1.45 Bcf/d) of incremental capacity to the NGTL System. Construction of the expansion program is nearing completion with an estimated capital cost of the program of $3.6 billion. As of December 31, 2023, $3.4 billion of the program's facilities have been placed in service, including all facilities required to declare contracts.

2022 NGTL System Expansion Program

The 2022 NGTL System Expansion Program was completed in 2023 and consists of approximately 166 km (103 miles) of new pipeline, one compressor unit and associated facilities and provides incremental capacity of approximately 773 TJ/d (722 MMcf/d) to meet firm-receipt and intra-basin delivery requirements with eight-year minimum terms. The capital cost of the program was $1.4 billion with all assets placed in service.

NGTL System/Foothills West Path Delivery Program

The NGTL System/Foothills West Path Delivery Program was a multi-year expansion of the NGTL System and Foothills system to facilitate incremental contracted export capacity connecting to the GTN pipeline system. The combined NGTL System and Foothills program consists of approximately 107 km (66 miles) of pipeline and associated facilities and is underpinned by 275 TJ/d (258 MMcf/d) of new firm-service contracts with terms that exceed 30 years. The capital cost of the program was $1.6 billion with all remaining assets placed in service in 2023.

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 and is underpinned by approximately 255 TJ/d (238 MMcf/d) of new firm-service contracts with 15-year terms. The estimated capital cost of the expansion is $0.5 billion. Construction activities commenced in 2022 with the pipeline placed in service in late 2023 and construction of the compressor stations is underway with anticipated in-service by second quarter 2024.

Valhalla North and Berland River Project

The VNBR project will serve aggregate system requirements and connect migrating supply to key demand markets, providing incremental capacity on the NGTL System of approximately 428 TJ/d (400 MMcf/d) and is expected to contribute to lower GHG emission intensity for the overall system. With an estimated capital cost of $0.6 billion, the project consists of approximately 33 km (21 miles) of new pipeline, one new non-emitting electric compressor unit and associated facilities. On December 21, 2023, we received approval from the CER to construct, own and operate the VNBR project with an anticipated in-service date in second quarter 2026.

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

year ended December 31 (millions of $)	2023	2022	2021
NGTL System	**2,201**	1,853	1,649
Canadian Mainline	**789**	770	838
Other Canadian pipelines[1]	**345**	183	188
Comparable EBITDA	**3,335**	2,806	2,675
Depreciation and amortization	**(1,325)**	(1,198)	(1,226)
Comparable EBIT	**2,010**	1,608	1,449
Specific item:			
Coastal GasLink impairment charge	**(2,100)**	(3,048)	—
Segmented earnings (losses)	**(90)**	(1,440)	1,449

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

Canadian Natural Gas Pipelines segmented losses in 2023 decreased by $1.4 billion compared to 2022. Canadian Natural Gas Pipelines segmented losses were $1.4 billion in 2022 compared to segmented earnings of $1.4 billion in 2021. A pre-tax impairment charge in 2023 of $2.1 billion (2022 – $3.0 billion) related to our equity investment in Coastal GasLink LP was recognized, which has been excluded from our calculation of comparable EBITDA and comparable EBIT. Refer to Note 8, Coastal GasLink, of our 2023 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 $)	2023	2022	2021
Net income			
NGTL System	**770**	708	631
Canadian Mainline	**230**	223	213
Average investment base			
NGTL System	**19,008**	17,493	15,560
Canadian Mainline	**3,709**	3,735	3,724

Net income for the NGTL System increased by $62 million in 2023 compared to 2022 and by $77 million in 2022 compared to 2021 mainly due to a higher average investment base resulting from continued system expansions. The NGTL System is operating under the 2020-2024 Revenue Requirement Settlement, which includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provides 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 in 2023 compared to 2022 and by $10 million in 2022 compared to 2021 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 $529 million higher in 2023 compared to 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. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information
- higher flow-through depreciation, financial charges and higher incentive earnings, partially offset by lower flow-through income taxes on the Canadian Mainline.

Comparable EBITDA for Canadian Natural Gas Pipelines in 2022 was $131 million higher than 2021 primarily due to the net effect of:

- higher flow-through financial charges and depreciation, as well as increased rate-base earnings on the NGTL System
- lower flow-through depreciation, partially offset by higher flow-through income taxes and financial charges and increased incentive earnings on the Canadian Mainline
- lower Coastal GasLink development fee revenue due to timing of revenue recognition.

Depreciation and amortization

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. Depreciation and amortization was $28 million lower in 2022 compared to 2021 due to one section of the Canadian Mainline being fully depreciated in 2021, partially offset by higher depreciation on the NGTL System from expansion facilities that were placed in service.

OUTLOOK

Comparable EBITDA and comparable earnings

Net income for Canadian rate-regulated pipelines is affected by changes in investment base, ROE and deemed capital structure, as well as by the terms of toll settlements approved by the CER. Under the current regulatory model, 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 2024 is expected to be consistent with 2023 mainly due to continued growth of the NGTL System as we advance expansion programs which extend and expand supply facilities, enhance delivery facilities in Alberta and provide incremental service at our major border delivery locations in response to requests for firm service on the system; offset by the Coastal GasLink incentive payment recognized in 2023 for achieving certain milestones. 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 2024 for the NGTL System and the Canadian Mainline to be consistent with 2023.

Capital expenditures

We incurred $2.6 billion in 2023 in our Canadian Natural Gas Pipelines business on growth projects and maintenance capital expenditures. We expect to incur approximately $1.2 billion in 2024, primarily on NGTL System expansion projects and maintenance capital expenditures, all of which are immediately reflected in investment base and related earnings.

We also contributed $3.0 billion to our investment in Coastal GasLink LP in 2023 and expect to contribute $0.9 billion in 2024. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information.

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 compliance regulation

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

Columbia Gas and Columbia Gulf Monetization

On October 4, 2023, we successfully 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). Columbia Gas and Columbia Gulf are held by a newly formed entity with GIP. Preceding the close of the equity sale, on August 8, 2023, Columbia Pipelines Operating Company LLC and Columbia Pipelines Holding Company LLC issued US$4.6 billion and US$1.0 billion of long-term, senior unsecured debt, respectively. The net proceeds from the offerings were used to repay existing intercompany indebtedness with TC Energy entities and directed towards reducing leverage. Refer to the Financial Condition section for additional information.

We continue to have a controlling interest in Columbia Gas and Columbia Gulf and we remain the operator of these 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.

ANR Section 4 Rate Case

ANR reached a settlement with its customers effective August 2022 and received FERC approval in April 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 second quarter 2023, previously accrued rate refund liabilities, including interest, were refunded to customers.

Columbia Gulf Rate Settlement

On July 7, 2023, Columbia Gulf filed an uncontested rate settlement which would set new recourse rates for Columbia Gulf effective March 1, 2024 and institute a rate moratorium through February 28, 2027. The revised rates are not expected to have a significant impact on our U.S. Natural Gas Pipelines segment comparable earnings. Columbia Gulf must file for new rates no later than March 1, 2029.

Line VB Strasburg

On July 25, 2023, a natural gas pipeline rupture on Columbia Gas occurred alongside Interstate 81 in Strasburg, Virginia. Emergency response procedures were enacted and the segment of impacted pipeline was isolated shortly thereafter. There were no reported injuries involved with this incident and no significant damage to surrounding structures. The pipeline has been operating at reduced pressure in accordance with PHMSA's Corrective Action Order (CAO) since July 28, 2023 and we are working with PHMSA under the CAO to return the system to normal operations as soon as possible. The Root Cause Failure Analysis (RCFA) findings indicated that similar pipeline segment locations within the Columbia Gas pipeline system require further testing; however, we do not expect the Line VB Strasburg event or the additional testing to have a material impact on our financial results.

North Baja XPress

In June 2023, the North Baja XPress project, an expansion project designed to expand capacity and meet increased customer demand on our North Baja pipeline, was placed in service. The capital cost of this project was approximately US$0.1 billion.

Bison XPress Project

In third quarter 2023, we approved the Bison XPress project, an expansion project on our Northern Border and Bison systems that will replace and upgrade certain facilities and provide much needed production egress from the Bakken basin to a delivery point at the Cheyenne Hub. The project has an anticipated in-service date in 2026. Total estimated project costs are US$0.4 billion, of which our share is US$0.2 billion, representing our 50 per cent equity investment in Northern Border and 100 per cent ownership in Bison.

GTN XPress Project

In October 2023, FERC provided a certificate order approving our GTN XPress project. The GTN XPress project is 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. The anticipated in-service date is in 2024 with an estimated project cost of US$0.1 billion.

VR and WR Projects

In November and December 2023, the FERC provided a certificate order approving our VR and WR projects, respectively. The VR project will provide incremental capacity from Greensville County, Virginia to delivery points in Norfolk, Virginia. The anticipated in-service date is late 2025 with an estimated project cost of US$0.7 billion. The WR project will provide mainline capacity to multiple points of delivery on our ANR System in Wisconsin. The anticipated in-service date is late 2025 with an estimated project cost of US$0.8 billion.

Virginia Electrification Project

In February 2024, the Virginia Electrification project, an expansion project that replaced and upgraded certain facilities through conversion to electric compression, reducing GHG emissions intensity along portions of our Columbia Gas system, was placed in service with a capital cost of approximately US$0.1 billion.

Heartland Project

In February 2024, we approved the Heartland project, an expansion project on our ANR system that is expected to increase capacity and improve system reliability. The Heartland project involves pipeline looping, compressor facility additions, as well as upgrades, and upon in-service, will increase ANR's overall market share in the Midwest region. The anticipated in-service date is late 2027 with an estimated project cost of US$0.9 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 11 for more information on non-GAAP measures we use.

The table below reflects 100 per cent of comparable EBITDA on assets we own or partially own and fully consolidate, as well as equity income for assets we own an equity interest in and do not consolidate.

year ended December 31 (millions of US$, unless otherwise noted)	2023	2022	2021
Columbia Gas[1]	**1,530**	1,511	1,529
ANR	**650**	582	592
Columbia Gulf[1]	**208**	207	220
GTN[2]	**202**	184	170
Great Lakes[2]	**183**	178	176
Portland[1]	**104**	101	78
Other U.S. pipelines[3]	**371**	379	310
Comparable EBITDA	**3,248**	3,142	3,075
Depreciation and amortization	**(692)**	(681)	(630)
Comparable EBIT	**2,556**	2,461	2,445
Foreign exchange impact	**895**	742	620
Comparable EBIT (Cdn$)	**3,451**	3,203	3,065
Specific items:			
Great Lakes goodwill impairment charge	**—**	(571)	—
Risk management activities	**80**	(15)	6
Segmented earnings (losses) (Cdn$)	**3,531**	2,617	3,071

1 Includes non-controlling interest. Refer to the Corporate - Financial results section for additional information.

2 Reflects 100 per cent of comparable EBITDA in GTN and Great Lakes, subsequent to the TC PipeLines, LP acquisition in March 2021.

3 Reflects comparable EBITDA from our ownership in our mineral rights business (CEVCO), North Baja, 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 2023 increased by $914 million compared to 2022 and decreased by $454 million in 2022 compared to 2021 and included the following specific items, which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- 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 2023 and 2022 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to 2022 and 2021, respectively. 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$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.

Comparable EBITDA for U.S. Natural Gas Pipelines was US$67 million higher in 2022 than 2021 primarily due to the net effect of:

- incremental earnings from growth projects placed in service
- increased earnings from our mineral rights business due to higher commodity prices
- a net increase in earnings from Columbia Gas following the FERC-approved settlement for higher transportation rates effective February 2021, partially offset by higher property taxes as a result of projects placed in service
- decreased earnings due to the impact of cold weather events and other discrete items recognized in 2021
- a decrease in earnings from ANR as a result of certain fourth quarter 2022 adjustments related to regulatory deferrals, partially offset by higher transportation rates effective August 1, 2022, both pursuant to the ANR uncontested rate settlement.

Depreciation and amortization

Depreciation and amortization was US$11 million higher in 2023 compared to 2022 and US$51 million higher in 2022 compared to 2021. The increase in depreciation in both years is primarily due to the net effect of new projects placed in service, while 2023 is partially offset by certain adjustments made in third quarter 2023.

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 regulators' decisions, as well as customer credit risk.

U.S. Natural Gas Pipelines comparable EBITDA in 2024 is expected to be higher than 2023. This is primarily due to the completion of expansion projects in 2023 and anticipated completion of expansion projects in 2024 on the Columbia Gas and GTN systems, as well as the in-service of the Gillis Access project and higher revenues on Columbia Gas due to return on and recovery of modernization capital costs. Our pipeline systems continue to see historically strong demand for service and we anticipate that during 2024, our assets will maintain the high utilization levels experienced in 2023. These positive results are expected to be partially offset by higher operational costs, reflective of continued increases to system utilization across our footprint and an anticipated increase in property taxes from capital projects placed in service.

Capital expenditures

We incurred a total of US$2.1 billion in 2023 on our U.S. natural gas pipelines and expect to incur approximately US$1.9 billion in 2024 primarily on our Gillis Access, Columbia Gulf, ANR and Columbia Gas expansion projects and Columbia Gas Modernization III program, 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 2024 to be approximately US$1.4 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 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 and in-service delay penalties, excluding force majeure events which provide schedule relief. Our Mexico pipelines have 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 with an expected in-service by mid-2025 and an estimated project cost of US$4.5 billion.

We placed the lateral section of the Villa de Reyes pipeline into service in third quarter 2023. Construction of the south section of the Villa de Reyes pipeline is targeted for mechanical completion in the second half of 2024, subject to successful resolution of stakeholder issues. Additionally, we continue to evaluate the development and completion of the Tula pipeline with the CFE, which is subject to a future FID. Due to the delay of an FID, effective November 1, 2023, we have suspended recording AFUDC on the assets under construction for the Tula pipeline project.

The strategic alliance provides the CFE with the ability to hold an equity interest in TGNH, which is conditional upon the CFE contributing capital, acquiring land and supporting permitting on the TGNH projects, subject to regulatory approvals from COFECE and the CRE. Upon in-service of the Southeast Gateway pipeline and the completion of certain other contractual obligations, the CFE's equity interest in TGNH will equal approximately 15 per cent, and will increase to approximately 35 per cent upon expiry of the contract in 2055. In December 2023, TGNH and the CFE obtained from COFECE, a favourable merger ruling and a determination that the proposed minority CFE equity participation in TGNH did not require a favourable cross participation opinion given that the CFE would not have a controlling interest in TGNH. TGNH and the CFE subsequently requested the CRE to confirm that a cross participation permit is not required given that the CFE would not have a controlling interest in TGNH. TGNH anticipates receiving CRE's approval in early 2024.

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

year ended December 31 (millions of US$, unless otherwise noted)	2023	2022	2021
TGNH[1]	**232**	164	118
Topolobampo	**157**	161	161
Sur de Texas[2]	**75**	112	113
Guadalajara	**61**	73	71
Mazatlán	**71**	67	70
Comparable EBITDA	**596**	577	533
Depreciation and amortization	**(66)**	(76)	(86)
Comparable EBIT	**530**	501	447
Foreign exchange impact	**186**	153	110
Comparable EBIT (Cdn$)	**716**	654	557
Specific item:			
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**80**	(163)	—
Segmented earnings (losses) (Cdn$)	**796**	491	557

1 Includes the operating sections of the Tamazunchale, Villa de Reyes and Tula pipelines.

2 Includes our share of 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 2023 increased by $305 million compared to 2022 and decreased by $66 million in 2022 compared to 2021 and included the impact of an $80 million recovery in 2023 (2022 – $163 million 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 29, Risk management and financial instruments, of our 2023 Consolidated financial statements for additional information.

A stronger U.S. dollar in 2023 and 2022 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. dollar-denominated operations in Mexico compared to 2022 and 2021, respectively. Refer to the Foreign Exchange section for additional information.

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

- higher earnings in TGNH primarily related to the commercial in-service of the north section of the Villa de Reyes pipeline (VdR North) and the east section of the Tula pipeline (Tula East) in third quarter 2022, as well as the commercial in-service of the lateral section of the Villa de Reyes pipeline (VdR Lateral) 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. Refer to the Foreign exchange section for additional information.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$44 million in 2022 compared to 2021 primarily due to higher revenues related to the commercial in-service of VdR North and Tula East in third quarter 2022.

In 2017, we entered into a MXN$21.3 billion unsecured revolving credit facility with the Sur de Texas joint venture. This peso-denominated inter-affiliate loan was fully repaid upon maturity on March 15, 2022 and replaced with a new U.S. dollar-denominated inter-affiliate loan. In July 2022, the Sur de Texas joint venture entered into an unsecured U.S. dollar-denominated term loan agreement with third parties and used the proceeds to fully repay the U.S. dollar-denominated inter-affiliate loan with TC Energy. Our share of related interest expense in Sur de Texas prior to this refinancing was fully offset by corresponding interest income recorded in Interest income and other in the Corporate segment.

Depreciation and amortization

Depreciation and amortization was US$10 million lower in 2023 compared to 2022 and in 2022 compared to 2021 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 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 2024 is expected to be higher than 2023 due to full-year, incremental revenue from VdR Lateral that was placed in commercial service in third quarter 2023.

Capital expenditures

We incurred a total of US$1.8 billion in 2023 primarily related to the construction of the Southeast Gateway, Villa de Reyes and Tula pipelines. We expect to incur approximately US$1.6 billion in 2024 to advance 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 99 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, natural gas demand 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 prudently incurred 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 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 ensure safe and reliable operations.

Liquids Pipelines

Our Liquids Pipelines business provides safe and reliable crude oil transportation through infrastructure extending from the WCSB in Canada to the U.S. Midwest and Gulf Coast. We offer long haul transportation from the WCSB to key refining and export markets in the U.S., as well as domestic transportation within Alberta and from Cushing, Oklahoma to the U.S. Gulf Coast.

Our Liquids Pipelines business includes:

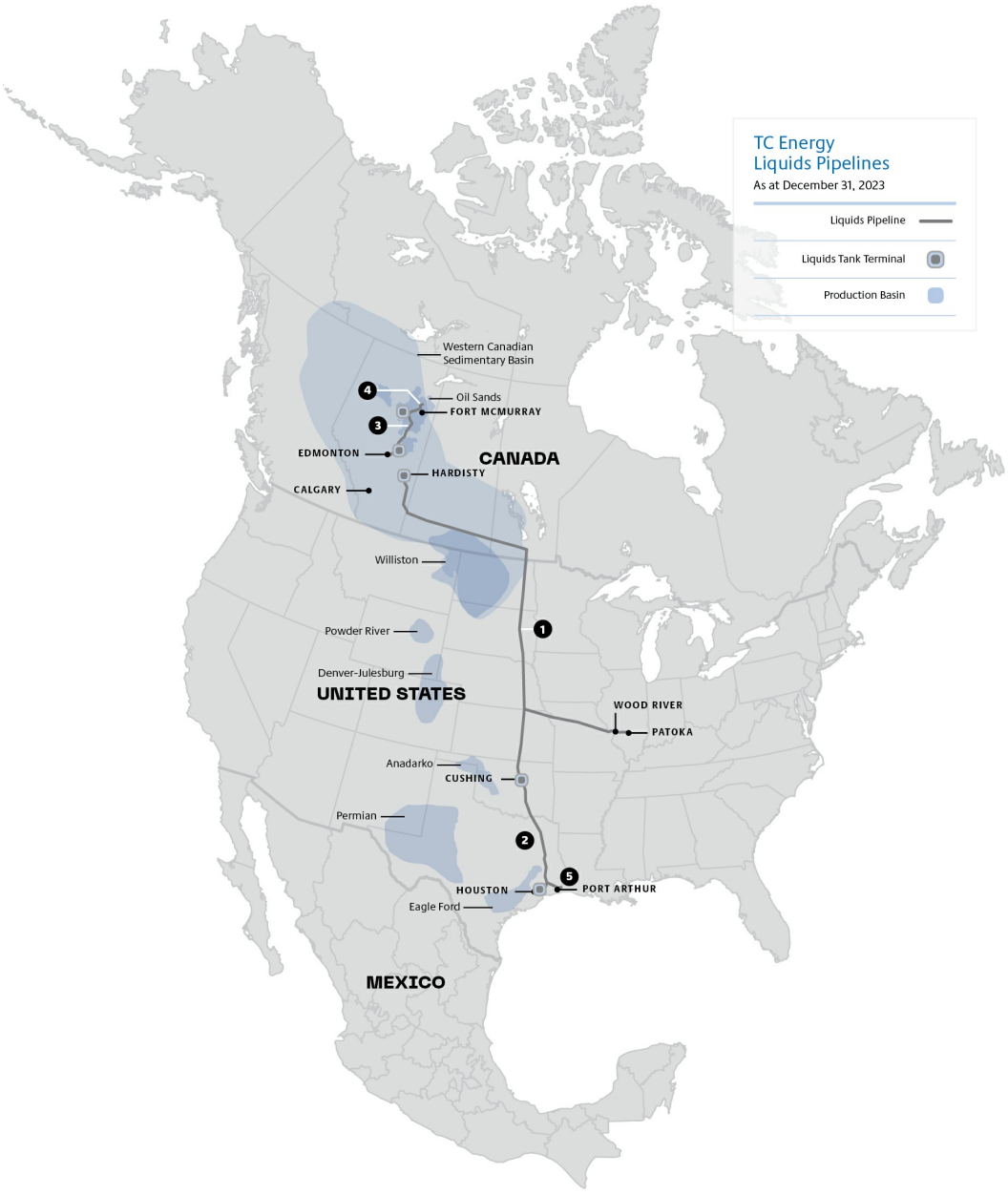
- wholly-owned liquids pipelines – approximately 4,400 km (2,700 miles)
- wholly-owned operational and term storage – approximately 7 million barrels
- partially-owned liquids pipelines – approximately 460 km (290 miles).

Strategy

We remain focused on the safe, secure and reliable operations of our Liquids Pipelines assets, while maximizing operational performance. We continue to expand our transportation service offerings and leverage existing infrastructure to pursue in-corridor growth opportunities, enabling increased optionality and market access for our customers and adding value to our business.

Recent highlights

- announced the proposed spinoff of our Liquids Pipelines business into a separate, investment-grade, publicly listed company named South Bow Corporation, which is expected to be completed in the second half of 2024, subject to receipt of required shareholder, court and regulatory approvals, favourable tax rulings and satisfaction of other customary closing conditions
- placed the Port Neches Link Pipeline System in service in first quarter 2023
- completed the recovery of all released volumes related to the Milepost 14 incident and returned Mill Creek to its natural flowing state. We will maintain our commitment to long-term reclamation and environmental monitoring activities.


TC Energy
Liquids Pipelines
As at December 31, 2023
Liquids Pipeline
Liquids Tank Terminal
Production Basin
Western Canadian
Sedimentary Basin
Oil Sands
FORT MCMURRAY
EDMONTON
CANADA
HARDISTY
CALGARY
Williston
Powder River
Denver-Julesburg
UNITED STATES
WOOD RIVER
PATOKA
Anadarko
CUSHING
Permian
HOUSTON
PORT ARTHUR
Eagle Ford
MEXICO
1
2
3
4
5

We are the operator and developer of the following:

		Length	Description	Ownership
	Liquids pipelines			
1	Keystone Pipeline System	4,327 km (2,689 miles)	Transports crude oil from Hardisty, Alberta to U.S. markets at Wood River and Patoka, Illinois, Cushing, Oklahoma and the U.S. Gulf Coast.	100 %
2	Marketlink		Transports crude oil from Cushing, Oklahoma to the U.S. Gulf Coast on facilities that form part of the Keystone Pipeline System.	100 %
3	Grand Rapids	460 km (286 miles)	Transports crude oil from the producing area northwest of Fort McMurray, Alberta to the Edmonton/Heartland, Alberta market region.	50 %
4	White Spruce	72 km (45 miles)	Transports crude oil from Canadian Natural Resources Limited's Horizon facility in northeast Alberta to the Grand Rapids pipeline.	100 %
5	Port Neches	6 km (4 miles)	Transports crude oil from the Keystone Pipeline System and other liquids terminals in the Port Arthur, Texas area to the Motiva Terminal in Port Neches, Texas.	74.9 %

UNDERSTANDING OUR LIQUIDS PIPELINES BUSINESS

Our Liquids Pipelines segment consists of crude oil pipeline and terminal assets. The business safely, securely and reliably transports crude oil from major supply sources to key refining and trading markets, where crude oil can be refined into petroleum products or marketed into other domestic or international markets. We also offer ancillary services, including storage at terminals, to provide our customers with increased delivery flexibility and increase the competitive position of our assets. In addition to our crude oil pipeline and terminal assets, we conduct marketing activities through a non-regulated marketing entity.

We provide pipeline transportation services to customers, primarily supported by long-term contracts providing certainty and generating stable earnings over the contract term. These long-term contracts provide for the recovery of costs incurred to construct our assets, with operating and maintenance costs primarily recovered through a variable flow-through toll. Uncontracted pipeline capacity is offered to the market on an uncommitted spot basis and through periodic open seasons, in accordance with regulatory requirements. Crude oil storage at terminals is offered to customers in exchange for fixed fee, term contracts.

In Canada, our pipeline systems and associated facilities are regulated by either the CER or AER, and in the U.S., by PHMSA and FERC or various state authorities. Combined, these entities regulate the construction, operation and abandonment of our pipeline infrastructure, as well as oversee the reasonableness of our tolls.

Keystone Pipeline System

Keystone Pipeline

The Keystone Pipeline System, our largest liquids pipeline asset, transports crude oil exported from Western Canada to various delivery points in the U.S. Midwest, and U.S. Gulf Coast. It also serves as the physical infrastructure for our Marketlink system, which leases capacity for the transportation of U.S. domestic crude receipts between Cushing, Oklahoma and the U.S. Gulf Coast. The Keystone Pipeline System operates in both Canada and the U.S. and is therefore subject to the common carrier obligations set by the CER and FERC in those jurisdictions, respectively.

Port Neches Link Pipeline

Our Port Neches Link Pipeline System provides crude oil transportation between our Keystone Pipeline System, as well as additional liquids terminals in the Port Arthur area, including the Phillips 66 Beaumont Terminal, to the Motiva Terminal in Port Neches, Texas. Port Neches Link Pipeline System is regulated by the Railroad Commission of Texas.

TC Energy Liquids Marketing

Our liquids marketing business provides customers with a variety of crude oil marketing services including transportation, storage and logistics, largely through the purchase and sale of physical crude oil. This business contracts for capacity on our pipelines, as well as third-party owned pipelines and tank terminals.

Intra-Alberta Pipeline Systems

Our two intra-Alberta liquids pipelines, Grand Rapids and White Spruce, provide crude oil transportation for producers in northern Alberta to move volumes between the oil sands region and the Edmonton/Heartland areas. These pipeline systems are regulated by the AER.

Business environment

Dynamic shifts in geopolitical events, government policy changes and various macroeconomic factors continue to impact global crude oil supply and demand balances. While the upstream sector remains focused on balancing capital discipline and growth, we expect crude oil demand to continue to increase this decade. Over a longer time horizon, we expect global demand to grow, before slowly declining in later decades; however, crude oil is expected to remain a vital source in helping the world meet its energy needs for decades to come. North America’s crude oil supply, inclusive of the WCSB, will remain critical in supporting long-term demand.

Supply outlook

Canada has the world's third largest crude oil reserves with over 160 billion barrels of proven and economically recoverable oil. Production from the WCSB, which is the main supply source for our liquids assets, was approximately 5.0 million Bbl/d in 2023 and is expected to grow by over 500,000 Bbl/d to 5.5 million Bbl/d by 2030. The oil sands, which are located within the WCSB and directly connected to our intra-Alberta assets, make up the majority of Canadian crude oil supply. The oil sands are considered a world class supply source given its decades-long reserve life, low base production decline and rapidly improving cost and environmental performance.

The U.S. is one of the largest crude oil producing countries in the world, with production exceeding 12 million Bbl/d in 2023. The majority of continental U.S. crude oil production is in the form of light tight oil from the Permian, Williston, Eagle Ford and Niobrara basins. U.S. refineries have been optimized through significant capital investments to refine a mix of light and heavy crude oils to produce an optimized refined products slate. With our Keystone Pipeline System's connection to key refining and export markets, we believe we are well positioned to attract barrels from major U.S. tight oil basins, which themselves are expected to grow through the end of the decade.

Demand

The U.S. is the primary source of crude oil demand in North America with refining capacity exceeding 18 million Bbl/d. Our Liquids Pipelines assets serve the U.S. Midwest and U.S. Gulf Coast refining markets, PADD 2 and PADD 3, respectively. PADD 2 represents 23 per cent and PADD 3 represents 56 per cent of U.S. refining throughput or in aggregate, 79 per cent. Many PADD 2 and PADD 3 refineries are large-scale, complex facilities, with deep conversion capacity for heavy crude oil. These markets are expected to remain globally competitive for decades to come due to their access to low-cost Canadian heavy and U.S. light crude oil, as well as their proximity to abundant low-cost natural gas supply, positioning them to be among the most profitable refineries in the world.

While domestic consumption makes up the predominance of current North American crude oil demand, exports are expected to grow, increasing their proportion of North American crude oil demand out past the end of the decade, driven by growth in emerging markets. Crude oil export from the U.S. Gulf Coast, a market served by our pipelines, is expected to grow from 3.2 million Bbl/d to 4.6 million Bbl/d by the early 2030s.

Strategic priorities

Our Liquids Pipelines assets strategically position our liquids business to provide competitive transportation solutions for growing supplies of Alberta and U.S. crude oil to the U.S. Midwest and the U.S. Gulf Coast.

Within our established risk preferences, we remain committed to:

- optimizing the operational performance and commercial value of our existing assets
- expanding and leveraging our existing infrastructure for growth expansions
- progressing our energy transition goals, including system operational improvements and reducing our GHG emissions.

The long-term contract profile supporting our business model provides stable tolls for our customers and stable revenues for our business. As we continually augment our connectivity to resilient supply and premium markets, our business is well positioned for further growth.

We believe that our Liquids Pipelines assets are well-positioned to capture production growth from the stable and resilient WCSB, which is needed to meet the growing U.S. Gulf Coast demand for secure Canadian heavy crude oil, as traditional offshore imports decline. With the continued growth of U.S. light tight oil production and a satisfied demand for light oil in North America, we will examine opportunities to expand our transportation services and extend our pipeline platform to include last-mile delivery connectivity to refineries and terminals with storage and marine export capabilities. We will also focus on leveraging our existing assets and development of projects to provide optionality for customers to reach new proximate supply sources.

We continually work with existing and potential customers to enhance their customer experience and provide competitive, reliable and efficient pipeline transportation and terminal services to meet their needs. The combination of the scale and strategic location of our assets assists in attracting additional volumes and growing our business.

We closely monitor the marketplace for strategic asset acquisitions, as well as joint venture or joint tolling opportunities to enhance our system connectivity or expand our footprint within North America. We remain disciplined in our approach and will position our business development activities strategically to capture opportunities within our risk preferences.

SIGNIFICANT EVENTS

Spinoff of Liquids Pipelines Business

On July 27, 2023, we announced plans to separate into two independent, investment-grade, publicly listed companies through the proposed spinoff of our Liquids Pipelines business into its own entity named South Bow Corporation. In addition to TC Energy shareholder and court approvals, the spinoff Transaction is subject to receipt of favourable tax rulings from Canadian and U.S. tax authorities, receipt of necessary regulatory approvals, and satisfaction of other customary closing conditions. We expect that the spinoff Transaction will be completed in the second half of 2024.

Under the spinoff Transaction, TC Energy shareholders will retain their current ownership in TC Energy's common shares and receive a pro-rata allocation of common shares in South Bow Corporation. The determination of the number of common shares in South Bow Corporation to be distributed to TC Energy shareholders will be determined prior to the closing of the spinoff Transaction, which is expected to be tax free to TC Energy's Canadian and U.S. shareholders.

For the year ended December 31, 2023, we incurred pre-tax Liquids Pipelines business separation costs related to the spinoff Transaction of $40 million ($34 million after tax), of which $3 million and $37 million pre tax were included in the results of our Liquids Pipelines and Corporate segments, respectively, and have been excluded from comparable measures.

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. We will maintain our commitment to long-term reclamation and environmental monitoring activities.

A CAO was issued by PHMSA in December 2022, and later amended in March 2023. The pipeline is operating subject to the Amended CAO (ACAO), which includes certain operating pressure restrictions. Under the ACAO, we expect to continue to fulfill our Keystone contract commitments.

A RCFA was conducted by an independent third party and was released on April 21, 2023. The RCFA revealed that a unique set of circumstances occurred at the rupture location, which likely originated during construction, with the primary cause of the rupture being a fatigue crack. A comprehensive remedial work plan is being implemented, including the RCFA's recommendations, to enhance pipeline integrity and safety performance of the system.

At December 31, 2022, we accrued an environmental remediation liability of $650 million, before expected insurance recoveries and not including potential fines and penalties, which was revised at June 30, 2023 to $794 million based on a review of costs and commitments incurred. At December 31, 2023, the remediation cost estimate remains unchanged. Appropriate insurance policies are in place and we believe that it remains probable that the majority of environmental remediation costs will be eligible for recovery under our existing insurance coverage. As of December 31, 2023, we have received $575 million (2022 – nil) from insurance proceeds related to the environmental remediation. The additional environmental remediation costs recognized in second quarter 2023 included $36 million that we estimate to be recoverable from our wholly-owned captive insurance subsidiary, which was recorded in Interest income and other in the Consolidated statement of income. This amount has been excluded from comparable measures.

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. 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.

In February 2023, FERC released its initial decision in respect of the complaint. As a result, we have recorded a one-time pre-tax charge of $57 million reflective of previously charged tolls between 2018 and 2022. This amount has been excluded from comparable measures. A final order from FERC is expected in 2024.

Port Neches

In March 2023, the Port Neches Link Pipeline System was placed in service, connecting the Keystone Pipeline System to Motiva's Port Neches Terminal, enabling last-mile connectivity to Motiva's 630,000 Bbl/d refinery.

In December 2023, Motiva, our partner in Port Neches LLC, exercised their option to increase their equity interest in the company. As a result, and in exchange for approximately US$25 million in proceeds, subject to the agreed upon post-closing adjustments, our ownership interest has decreased from 95 per cent to 74.9 per cent.

Keystone XL

In September 2022, the International Centre for Settlement of Investment Disputes formally constituted a tribunal to hear our request for arbitration under NAFTA. In April 2023, the tribunal suspended the proceeding, granting a request from the U.S. Department of State to decide the jurisdictional grounds of the case as a preliminary matter. A hearing on the jurisdictional matter is set to occur in second quarter 2024. In April 2023, The Government of Alberta filed its own request for arbitration, which will proceed separately from our claim.

Keystone XL termination activities will continue in 2024 and include asset dispositions and preservation. We will continue to coordinate with regulators, stakeholders and Indigenous groups to meet our environmental and regulatory commitments.

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

year ended December 31 (millions of $)	2023	2022	2021
Keystone Pipeline System[1]	**1,389**	1,304	1,448
Intra-Alberta pipelines[2]	**70**	71	87
Other[1]	**(2)**	(9)	(9)
Comparable EBITDA	**1,457**	1,366	1,526
Depreciation and amortization	**(338)**	(329)	(318)
Comparable EBIT	**1,119**	1,037	1,208
Specific items:			
Keystone regulatory decisions	**(57)**	(27)	—
Keystone XL preservation and other	**(18)**	(25)	(43)
Liquids Pipelines business separation costs	**(3)**	—	—
Keystone XL asset impairment charge and other	**4**	118	(2,775)
Gain on sale of Northern Courier	—	—	13
Risk management activities	**(34)**	20	(3)
Segmented earnings (losses)	**1,011**	1,123	(1,600)
Comparable EBITDA denominated as follows:			
Canadian dollars	**382**	383	417
U.S. dollars	**796**	754	884
Foreign exchange impact	**279**	229	225
Comparable EBITDA	**1,457**	1,366	1,526

1 Liquids marketing results were previously disclosed separately, but almost fully relate to marketing activities with respect to the Keystone Pipeline System. For 2022 and comparative periods, liquids marketing results have been reclassified within Keystone Pipeline System.

2 Intra-Alberta pipelines included Grand Rapids, White Spruce and Northern Courier. In November 2021, we sold our remaining 15 per cent interest in Northern Courier.

Liquids Pipelines segmented earnings decreased by $112 million in 2023 compared to 2022 and increased by $2,723 million in 2022 compared to 2021 and included the following specified items, which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a $57 million pre-tax charge in 2023 as a result of the FERC Administrative Law Judge initial decision issued in February 2023 in respect of a tolling-related complaint pertaining to amounts recognized from 2018 to 2022 and a $27 million pre-tax charge due to the CER decision issued in December 2022 in respect of a tolling-related complaint pertaining to amounts reflected in 2021 and 2022. Refer to the Liquids Pipelines – Significant events section for additional information
- pre-tax preservation and other costs in 2023 of $18 million (2022 – $25 million) related to the preservation and storage of the Keystone XL pipeline project assets which could not be accrued as part of the Keystone XL asset impairment charge
- a pre-tax charge of $3 million incurred in 2023 due to Liquids Pipelines business separation costs related to the spinoff Transaction. Refer to the Liquids Pipelines – Significant events section for additional information
- a $4 million pre-tax adjustment in 2023 (2022 – $118 million) to the 2021 Keystone XL asset impairment charge and other resulting from the net effect of the gain on sale of Keystone XL project assets and adjustments to the estimate for contractual and legal obligations related to termination activities
- a $2.8 billion pre-tax asset impairment charge was recognized in 2021 associated with the termination of the Keystone XL pipeline project and related projects following the January 2021 revocation of the Presidential Permit, net of expected contractual recoveries and other contractual and legal obligations
- pre-tax gain of $13 million in 2021 related to the sale of the remaining 15 per cent interest in Northern Courier
- unrealized gains and losses from changes in the fair value of derivatives related to our liquids marketing business.

A stronger U.S. dollar in 2023 and 2022 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to 2022 and 2021, respectively. Refer to the Foreign Exchange section for additional information.

Comparable EBITDA for Liquids Pipelines was $91 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
- a stronger U.S. dollar as described above.

Comparable EBITDA for Liquids Pipelines was $160 million lower in 2022 compared to 2021 primarily due to the net effect of:

- lower rates and volumes on the U.S. Gulf Coast section of the Keystone Pipeline System, partially offset by higher long-haul contracted volumes and approximately 20,000 Bbl/d of long-term contracts from the 2019 Open Season that were commercialized in April 2022, with an additional 10,000 Bbl/d in September 2022
- liquids marketing earnings for 2022 decreased relative to 2021 due to lower margins and volumes
- the CER decision on the tolling-related complaint in respect of amounts invoiced in 2022
- a stronger U.S. dollar as described above.

Depreciation and amortization

Depreciation and amortization was $9 million higher in 2023 compared to 2022 and $11 million higher in 2022 compared to 2021 primarily as a result of a stronger U.S. dollar.

OUTLOOK

Comparable EBITDA

Comparable EBITDA in 2024 is expected to be consistent with 2023. Comparable EBITDA in 2024 does not take into consideration the impact of the spinoff Transaction as it is subject to TC Energy shareholder approval, court approval, favourable tax rulings, other regulatory approvals and satisfaction of other customary closing conditions.

Capital expenditures

We incurred a total of $44 million in 2023 primarily related to capital projects in the U.S. Gulf Coast and on our operating pipelines and expect to incur approximately $0.2 billion in 2024.

BUSINESS RISKS

The following are risks specific to our Liquids Pipelines business. Refer to page 99 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.

Operations

Operating our liquids pipelines safely and reliably while optimizing available capacity are essential drivers of our business success. Interruptions in our pipeline operations may impact our throughput capacity and result in our inability to deliver on our contracted volume obligations and to capture spot volume opportunities. We manage these risks and possible impacts to local communities using environmental risk-based preventive maintenance programs, effective capital investments and a highly skilled workforce. We utilize in-line inspection equipment to monitor our pipelines regularly and perform repairs and preventative maintenance whenever necessary.

Regulatory and government

Decisions by Canadian and U.S. regulators can have a significant impact on the design, construction, operations and financial performance of our liquids pipelines. Shifts in government policy can impact the ability to grow our business. Public opinion about crude oil development and production may also have an adverse impact on regulatory processes. In conjunction with this, there are individuals and special interest groups that express opposition to oil usage for energy by lobbying against the construction and operation of liquids pipelines. Changing environmental requirements or revisions to the current regulatory process may adversely impact the timing or ability to obtain approvals for our liquids pipelines. We manage these risks by continuously monitoring regulatory and government policy developments to determine their possible impact on our Liquids Pipelines business and by working closely with our stakeholders in the development and operation of our assets.

Crude oil supply and demand for pipeline capacity

A decrease in demand for refined products could adversely impact the price that crude oil producers receive for their product. In the long term, lower crude oil prices could cause producers to curtail their investment in the further development of crude oil supplies. Depending on the severity, these factors could negatively impact opportunities to expand our liquids pipelines infrastructure and, in the longer term, to re-contract with customers as current agreements expire.

Competition

As we continue to further develop our competitive position in the North American liquids transportation market to connect growing crude oil supplies between key North American producing regions and demand markets, we may face competition from other companies which also seek to transport crude oil to the same markets. Our success will be dependent on our ability to offer and contract transportation services on terms that are market competitive.

Liquids marketing

Our liquids marketing business provides customers with a variety of crude oil marketing services including transportation, storage and logistics, primarily through the purchase and sale of physical crude oil. Changing market conditions could adversely impact the value of the underlying capacity contracts and margins realized. Availability of alternative pipeline systems that can deliver into the same areas can also impact contract value. The liquids marketing business complies with our risk management policies which are described in the Other Information – Risk oversight and enterprise risk management section.

Market Volatility

The cyclical nature of commodity prices may influence the pace at which our customers expand their operations. This can impact the rate of output growth in our industry, the value of our services as contracts expire, and timing for the demand of transportation services and/or new liquids infrastructure. We seek to mitigate this risk through term contracting and offering a market competitive transportation service.

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 low-carbon solutions for our customers and industry.

Our Power and Energy Solutions business includes approximately 4,600 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 both the U.S. and Canada from wind and solar facilities. We continue to pursue generation assets and PPA opportunities in Canada and the U.S.

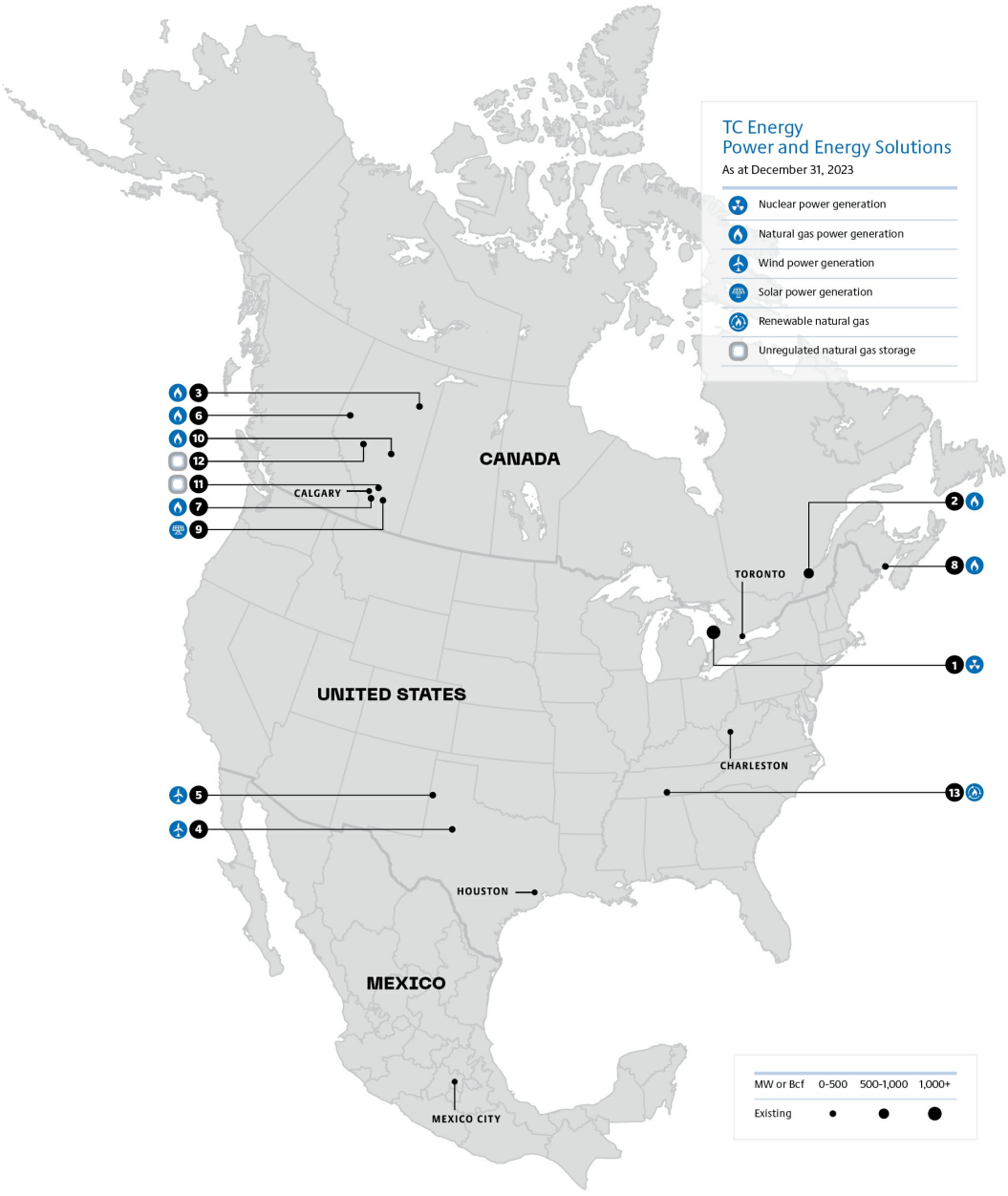
We also own and operate approximately 118 Bcf of non-regulated natural gas storage capacity in Alberta.

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. 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. Long term, we believe there will be a growing need for a reliable supply of resources as energy transition unfolds. We can play a vital role in energy transition 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

- under the Bruce Power life extension program, the Unit 6 MCR was completed and successfully placed in commercial operations in third quarter 2023, ahead of schedule and within budget. In March 2023, Unit 3 was removed from service and began its MCR construction starting in second quarter 2023. The final basis of estimate for the Unit 4 MCR was filed with the IESO in fourth quarter 2023, and received approval on February 8, 2024
- acquired 100 per cent of the Class B Membership Interests in the 155 MW Fluvanna Wind Farm and 148 MW Blue Cloud Wind Farm
- completed construction of the 81 MW Saddlebrook Solar project, with full commercial operation commencing on January 5, 2024
- announced we will continue to advance the OPSP with our prospective partner, the Saugeen Ojibway Nation.


TC Energy
Power and Energy Solutions
As at December 31, 2023
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
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 4,642 MW. We operate each facility except for Bruce Power.

		Generating capacity (MW)	Type of fuel	Description	Ownership
	Power assets				
1	Bruce Power[1]	3,170	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. Refer to the Power and Energy Solutions – Significant events section for additional information.

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 6,560 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 hold a 48.3 per cent ownership 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, commenced in January 2020 and was placed back into commercial operation in third quarter 2023 ahead of schedule and within budget despite challenges associated with the COVID-19 pandemic. The Unit 3 MCR, the second unit in the MCR program, commenced in first quarter 2023 and has an expected completion in 2026. In the fourth quarter 2023, the Unit 4 MCR final cost and schedule estimate was submitted to the IESO and approved on February 8, 2024. We expect the Unit 4 MCR to commence in first quarter 2025 with expected completion in 2028. Investments in the remaining three units' MCR programs are expected to continue through 2033. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available for Bruce Power and the IESO.

Along with the MCR life extension program, Bruce Power's Project 2030 has a goal of achieving site peak output of 7,000 MW by 2033 in support of climate change targets and future clean energy needs. Project 2030 will focus on continued asset optimization, innovation and leveraging new technology, which could include integration with storage and other forms of energy, to increase the site peak output. Project 2030 is arranged in three stages with the first two stages fully approved for execution. Stage 1 started in 2019 and is expected to add 150 MW of output and Stage 2, which began in early 2022, is targeting another 200 MW.

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, 2023, 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 continues to advance a project to expand isotope production from its reactors with a focus on Lutetium-177, another medical isotope used in the treatment of prostate cancer and neuroendocrine tumors. 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.

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 400 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.

SIGNIFICANT EVENTS

Bruce Power Life Extension

The Unit 6 MCR, which began in January 2020, was declared commercially operational on September 14, 2023, ahead of schedule and within budget despite challenges from the COVID-19 pandemic.

On March 1, 2023, Unit 3 was removed from service and began its MCR construction in second quarter 2023 with a return to service expected in 2026.

The final cost and schedule estimate for the Unit 4 MCR program was submitted to the IESO on December 13, 2023, and received approval on February 8, 2024. The Unit 4 MCR is expected to commence in first quarter 2025 with an expected completion in 2028.

Renewable Energy Contracts and/or Investment Opportunities

In second quarter 2023, we finalized contracts to sell 50 MW under our 24-by-7 carbon-free power offering in Alberta. Contract terms range from 15 to 20 years and are expected to commence in 2025.

In November 2023, a majority of the 297 MW Sharp Hills Wind Farm achieved commercial operation resulting in the commencement of our 15-year PPA for 100 per cent of the power produced and the rights to all environmental attributes from the facility.

Texas Wind Farm Acquisitions

On March 15, 2023, we acquired 100 per cent of the Class B Membership Interests in the 155 MW Fluvanna Wind Farm located in Scurry County, Texas for US$99 million, before post-closing adjustments. Additionally, on June 14, 2023, we acquired 100 per cent of the Class B Membership Interests in the 148 MW Blue Cloud Wind Farm located in Bailey County, Texas for US$125 million, before post-closing adjustments.

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 under the provisions of each tax equity agreement and are recorded in Net income attributable to non-controlling interests in the Consolidated statement of income.

Saddlebrook Solar

On October 25, 2023, we completed construction of Saddlebrook Solar, an 81 MW facility located near Aldersyde, Alberta and began commissioning activities including supplying generation to the Alberta market. Full commercial operation was achieved on January 5, 2024. The project was partially supported with funding from Emissions Reduction Alberta and Lockheed Martin.

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

The table below reflects 100 per cent of comparable EBITDA on assets we own or partially own and fully consolidate, as well as equity income for assets we own an equity interest in and do not consolidate.

year ended December 31 (millions of $)	2023	2022	2021
Bruce Power[1]	**680**	552	397
Canadian Power	**334**	322	253
Natural Gas Storage and other[2]	**6**	33	19
Comparable EBITDA	**1,020**	907	669
Depreciation and amortization	**(92)**	(72)	(78)
Comparable EBIT	**928**	835	591
Specific items:			
Bruce Power unrealized fair value adjustments	**7**	(17)	14
Gain on sale of Ontario natural gas-fired power plants	**—**	—	17
Risk management activities	**69**	15	6
Segmented earnings (losses)	**1,004**	833	628

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 $171 million in 2023 compared to 2022 and increased by $205 million in 2022 compared to 2021 and included the following specific items, which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a $17 million pre-tax recovery of certain costs from the IESO in 2021 associated with the Ontario natural gas-fired power plants sold in April 2020
- 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 $113 million in 2023 compared to 2022 primarily due to:

- 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. Additional financial and operating information on Bruce Power is provided below
- 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 across the segment.

Comparable EBITDA for Power and Energy Solutions increased by $238 million in 2022 compared to 2021 primarily due to the net effect of:

- positive contributions from Bruce Power primarily due to a higher contract price
- improved Canadian Power earnings primarily due to higher realized power prices
- increased Natural Gas Storage and other results from higher realized Alberta natural gas storage spreads in 2022.

Depreciation and amortization

Depreciation and amortization increased by $20 million in 2023 compared to 2022 primarily due to the acquisition of the Texas Wind Farms in the first half of 2023. Depreciation was lower by $6 million in 2022 compared to 2021 as a result of certain adjustments in 2022.

Bruce Power results

Bruce Power results reflect our proportionate share. Comparable EBITDA and comparable EBIT are non-GAAP measures. Refer to page 11 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)	2023	2022	2021
Items included in comparable EBITDA and comparable EBIT are comprised of:			
Revenues[1]	**1,941**	1,848	1,642
Operating expenses	**(917)**	(924)	(922)
Depreciation and other	**(344)**	(372)	(323)
Comparable EBITDA and comparable EBIT[2]	**680**	552	397
Bruce Power – other information			
Plant availability[3,4]	**92 %**	86 %	86 %
Planned outage days[4]	**106**	302	321
Unplanned outage days	**62**	34	22
Sales volumes (GWh)[5]	**20,447**	20,610	20,542
Realized power price per MWh[6]	**$94**	$89	$80

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.

The Unit 6 MCR, which began in 2020, was declared commercially operational on September 14, 2023, ahead of schedule and within budget. The Unit 3 MCR commenced on March 1, 2023 with a return to service expected in 2026.

A planned outage on Unit 4 was completed in second quarter 2023 and on Unit 8 in fourth quarter 2023. The final cost and schedule estimate for the Unit 4 MCR program was submitted to the IESO on December 13, 2023, and received approval on February 8, 2024.

Planned maintenance was completed on all units in 2022. In 2021, planned maintenance on Units 1 and 3 was completed and an outage on Unit 7 commenced in the fourth quarter.

OUTLOOK

Comparable EBITDA

Power and Energy Solutions comparable EBITDA in 2024 is expected to be higher than 2023 primarily from increased Bruce Power equity income due to the full year impact of Unit 6 after its return to service in September 2023 and the expected April 1, 2024 contract price increase. Lower Alberta power prices in 2024 are expected, reducing contributions from Canadian Power.

Planned maintenance at Bruce Power in 2024 is currently scheduled to begin on Unit 1 in the first quarter and on Units 5 to 8 in the second quarter. The average 2024 plant availability percentage, excluding the Unit 3 MCR program, is expected to be in the low-90 per cent range.

Capital expenditures

We incurred $0.9 billion in 2023 for our share of the Unit 3 and Unit 6 MCR programs for Bruce Power, construction of Saddlebrook Solar and other maintenance capital projects across the segment. We expect to incur approximately $0.9 billion in 2024 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 99 for information about general risks related to TC Energy as a whole, including other operational, safety and financial risks. The Power and Energy Solutions marketing business complies with our risk management policies which are described in the Other information – Risk oversight and enterprise risk management section.

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 both regulated and deregulated power markets in Canada and the United States. 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. Seasonal changes in temperature can reduce 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 low-carbon economy in North America and, as a result, we face competition in building low-carbon platforms with energy and financial options to provide customer-driven solutions for energy transition.

Execution and capital costs

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

Corporate

SIGNIFICANT EVENTS

2016 Columbia Pipeline Acquisition Lawsuit

In June 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. The Court awarded US$1 per share in damages to the plaintiffs and total damages, which are presently estimated at US$400 million plus statutory interest. Post-trial briefing and argument has concluded and a decision from the Court allocating liability as between TC Energy and the former CPG executives is expected sometime in the first half of 2024. Management expects to proceed with an appeal following the Court's determination of total damages and TC Energy's allocated share.

Focus Project

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

Certain initiatives have been implemented in 2023, including launching a new simplified operational management system in support of enhanced safety performance, efficiencies in certain processes related to capital projects and reducing corporate costs. We expect to continue to implement additional initiatives beyond 2023, primarily in our Natural Gas Pipelines business, with benefits in the form of enhanced productivity, lower costs, and higher revenues, with the majority of these benefits expected to be realized by our customers. We also have additional safety initiatives as part of a three-year safety improvement plan.

At December 31, 2023, we have incurred pre-tax costs of $124 million for the Focus Project primarily related to external consulting and severance costs, of which $65 million was recorded in Plant operating costs and other in the Consolidated statement of income and was removed from comparable amounts. Of the remaining costs incurred, $23 million was recorded in Plant operating costs and other with offsetting revenues in the Consolidated statement of income related to costs recoverable through regulatory and commercial tolling structures, the net effect of which had no impact on net income. An additional $36 million was allocated to capital projects. No material consulting costs are expected to be incurred in 2024.

Asset Divestiture Program

On October 4, 2023, TC Energy successfully completed the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf which significantly accelerated our deleveraging goal. We continue to evaluate incremental capital rotation opportunities to further strengthen our financial position.

2023 Canada Federal Budget

On March 28, 2023, the Canadian Federal Government delivered its 2023 Budget. As part of this budget, several changes were announced to interest deductibility rules, global minimum tax proposals and other tax measures. We do not expect a material impact on our financial performance and cash flows in the near term, but we will continue to monitor any developments.

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

ar ended December 31 llions of $)	2023	2022	2021
mparable EBITDA and comparable EBIT	**(14)**	(20)	(24)
ecific items:			
ocus Project costs	**(65)**	—	—
iquids Pipelines business separation costs	**(37)**	—	—
oreign exchange gains – inter-affiliate loans[1]	**—**	28	41
oluntary Retirement Program	**—**	—	(63)
gmented earnings (losses)	**(116)**	8	(46)

1 Reported in Income (loss) from equity investments in the Consolidated statement of income.

In 2023, Corporate segmented losses were $116 million compared to segmented earnings of $8 million in 2022. In 2022, Corporate segmented earnings were $8 million compared to segmented losses of $46 million in 2021.

Corporate segmented earnings (losses) included the following specific items which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax charge of $65 million recorded in 2023 related to Focus Project costs. Refer to the Corporate – Significant events section for additional information
- a pre-tax charge of $37 million incurred in 2023 due to Liquids Pipelines business separation costs related to the spinoff Transaction. Refer to the Liquids Pipelines – Significant events section for additional information
- foreign exchange gains in 2022 and 2021 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
- a pre-tax charge of $63 million in 2021 for the VRP offered in 2021.

Comparable EBITDA and comparable EBIT for Corporate increased by $6 million in 2023 from a loss of $20 million in 2022 due to lower litigation costs. Comparable EBITDA and comparable EBIT for Corporate in 2022 was generally consistent with 2021.

OTHER INCOME STATEMENT ITEMS

Interest expense

year ended December 31 (millions of $)	2023	2022	2021
Interest expense on long-term debt and junior subordinated notes			
Canadian dollar-denominated	**(895)**	(776)	(712)
U.S. dollar-denominated	**(1,692)**	(1,267)	(1,259)
Foreign exchange impact	**(592)**	(383)	(320)
	(3,179)	(2,426)	(2,291)
Other interest and amortization expense	**(261)**	(189)	(85)
Capitalized interest	**187**	27	22
Interest expense included in comparable earnings	**(3,253)**	(2,588)	(2,354)
Specific items:			
Keystone regulatory decisions	**(10)**	—	—
Keystone XL preservation and other	**—**	—	(6)
Interest expense	**(3,263)**	(2,588)	(2,360)

Interest expense increased by $675 million in 2023 compared to 2022 and increased by $228 million in 2022 compared to 2021. The following specific items have been removed from our calculation of interest expense included in comparable earnings:

- carrying charges of $10 million in 2023 as a result of a pre-tax charge related to the FERC Administrative Law Judge initial decision on Keystone. This decision was issued in February 2023 in respect of a tolling-related complaint pertaining to amounts recognized from 2018 to 2022
- a $6 million charge in 2021 related to the Keystone XL project-level credit facility for the period following the revocation of the Presidential Permit for the Keystone XL pipeline project.

Interest expense included in comparable earnings in 2023 increased by $665 million compared to 2022 primarily due to the net effect of:

- long-term debt issuances, net of 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 8, Coastal GasLink, of our 2023 Consolidated financial statements for additional information.

Interest expense included in comparable earnings in 2022 increased by $234 million compared to 2021 mainly due to the net effect of:

- higher interest rates on increased levels of short-term borrowings
- long-term debt and junior subordinated note issuances, net of maturities
- the foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest expense.

Refer to the Financial Condition section for additional information.

Allowance for funds used during construction

year ended December 31 (millions of $)	2023	2022	2021
Allowance for funds used during construction			
Canadian dollar-denominated	**102**	157	140
U.S. dollar-denominated	**350**	161	101
Foreign exchange impact	**123**	51	26
Allowance for funds used during construction	**575**	369	267

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. Due to the delay of an FID, effective November 1, 2023, we have suspended recording AFUDC on the assets under construction for the Tula pipeline project.

AFUDC increased by $102 million in 2022 compared to 2021. The increase in Canadian dollar-denominated AFUDC is primarily related to increased capital expenditures on the NGTL System. The increase in U.S. dollar-denominated AFUDC is due to 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, partially offset by the impact of decreased capital expenditures and projects placed in service on our U.S. natural gas pipeline projects.

Foreign exchange gains (losses), net

year ended December 31 (millions of $)	2023	2022	2021
Foreign exchange gains (losses), net included in comparable earnings	**118**	(8)	254
Specific items:			
Foreign exchange gains (losses), net – intercompany loan	**(44)**	—	—
Foreign exchange losses – inter-affiliate loan	**—**	(28)	(41)
Risk management activities	**246**	(149)	(203)
Foreign exchange gains (losses), net	**320**	(185)	10

Foreign exchange gains were $320 million in 2023 compared to foreign exchange losses of $185 million in 2022 and foreign exchange gains of $10 million in 2021. 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. Refer to the Non-GAAP measures section for additional information
- unrealized gains and losses from changes in the fair value of derivatives used to manage our foreign exchange risk
- 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 – Financial risks, financial instruments and related party transactions sections for additional information.

Foreign exchange gains included in comparable earnings were $118 million in 2023 compared to foreign exchange losses of $8 million in 2022. The change was primarily due to the net effect of:

- higher realized gains on derivatives used to manage our foreign exchange exposure to net liabilities in Mexico
- higher net realized losses on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- higher foreign exchange losses on the revaluation of our peso-denominated net monetary liabilities to U.S. dollars.

Foreign exchange losses included in comparable earnings were $8 million in 2022 compared to foreign exchange gains of $254 million in 2021. The change was primarily due to the net effect of:

- net realized losses in 2022 compared to realized gains in 2021 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- foreign exchange losses in 2022 compared to gains in 2021 on the revaluation of our peso-denominated net monetary liabilities to U.S. dollars
- higher realized gains on derivatives used to manage our foreign exchange exposure to net liabilities in Mexico.

Interest income and other

year ended December 31 (millions of $)	2023	2022	2021
Interest income and other included in comparable earnings	**278**	146	190
Specific item:			
Milepost 14 insurance expense	**(36)**	—	—
Interest income and other	**242**	146	190

Interest income and other increased by $96 million in 2023 compared to 2022 and decreased by $44 million in 2022 compared to 2021. Interest income and other in 2023 included a $36 million accrued insurance expense related to the Milepost 14 incident, which is an estimate of the insurance proceeds for environmental remediation that we expect to receive from our wholly-owned captive insurance subsidiary. This expense has been removed from our calculation of Interest income and other included in comparable earnings. Refer to the Non-GAAP measures section for additional information.

Interest income and other included in comparable earnings 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.

Interest income and other included in comparable earnings decreased by $44 million in 2022 compared to 2021, due to the March 2022 refinancing of the inter-affiliate loan receivable from Sur de Texas joint venture and subsequent repayment of the loan on July 29, 2022.

Income tax (expense) recovery

year ended December 31 (millions of $)	2023	2022	2021
Income tax expense included in comparable earnings	**(1,037)**	(813)	(830)
Specific items:			
Coastal GasLink impairment charge	**157**	405	—
Keystone regulatory decisions	**15**	7	—
Focus Project costs	**17**	—	—
Liquids Pipelines business separation costs	**6**	—	—
Keystone XL preservation and other	**4**	6	12
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**(25)**	49	—
Keystone XL asset impairment charge and other	**14**	(123)	641
Great Lakes goodwill impairment charge	**—**	40	—
Settlement of Mexico prior years' income tax assessments	**—**	(196)	—
Voluntary Retirement Program	**—**	—	15
Sale of Northern Courier	**—**	—	6
Sale of Ontario natural gas-fired power plants	**—**	—	(10)
Bruce Power unrealized fair value adjustments	**(2)**	4	(3)
Risk management activities	**(91)**	32	49
Income tax (expense) recovery	**(942)**	(589)	(120)

Income tax expense in 2023 increased by $353 million compared to 2022 and increased by $469 million in 2022 compared to 2021.

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

2023

- a $157 million income tax recovery related to the impairment of our equity investment in Coastal GasLink LP
- a $14 million U.S. minimum tax recovery on the 2021 Keystone XL asset impairment charge and other related to the termination of the Keystone XL pipeline project.

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
- a $123 million income tax expense as part of the Keystone XL asset impairment charge and other that includes a $96 million U.S. minimum tax related to the termination of the Keystone XL pipeline project.

2021

- income tax impact of the Keystone XL pipeline project asset impairment charge and other.

Income tax expense included in comparable earnings in 2023 increased by $224 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 inflation adjustments. Refer to the Foreign exchange section for additional information.

Income tax expense included in comparable earnings in 2022 decreased by $17 million compared to 2021 primarily due to lower flow-through income taxes and higher foreign tax rate differentials, partially offset by higher earnings subject to tax and other various valuation allowances.

Net (income) loss attributable to non-controlling interests

year ended December 31 (millions of Canadian $)	Non-Controlling Interests Ownership at December 31, 2023	2023	2022	2021
Columbia Gas and Columbia Gulf[1]	40.0%	**(143)**	—	—
Portland Natural Gas Transmission System	38.3%	**(41)**	(37)	(30)
Texas Wind Farms	100%[2]	**38**	—	—
TC PipeLines, LP	nil[3]	**—**	—	(60)
Redeemable non-controlling interest	nil	**—**	—	(1)
Net (income) loss attributable to non-controlling interests		**(146)**	(37)	(91)

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 GIP.
2 The Texas Wind Farms have tax equity investors that own 100 per cent of the Class A Membership Interests, to which a percentage of earnings, tax attributes and cash flows are allocated.
3 Prior to the March 3, 2021 acquisition, the non-controlling interest in TC PipeLines, LP was 74.5 per cent.

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. Refer to the U.S. Natural Gas Pipelines – Significant events and Power and Energy Solutions – Significant events sections for additional information.

Net income attributable to non-controlling interests decreased by $54 million in 2022 compared to 2021 primarily as a result of the March 2021 acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy. Subsequent to the acquisition, TC PipeLines, LP became an indirect, wholly-owned subsidiary of TC Energy.

Preferred share dividends

year ended December 31 (millions of $)	2023	2022	2021
Preferred share dividends	**(93)**	(107)	(140)

Preferred share dividends decreased by $14 million in 2023 compared to 2022 and $33 million in 2022 compared to 2021 primarily due to the redemption of preferred shares in 2022 and 2021, partially offset by higher floating dividend rates on certain series of preferred shares.

Foreign exchange

Foreign exchange related to U.S. dollar dominated 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. The balance of the 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, 2023, 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 along with the majority of our Liquids Pipelines business. Comparable EBITDA is a non-GAAP measure.

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

year ended December 31 (millions of US$)	2023	2022	2021
Comparable EBITDA			
U.S. Natural Gas Pipelines	**3,248**	3,142	3,075
Mexico Natural Gas Pipelines[1]	**596**	602	602
Liquids Pipelines	**796**	754	884
	4,640	4,498	4,561
Depreciation and amortization	**(954)**	(952)	(911)
Interest on long-term debt and junior subordinated notes	**(1,692)**	(1,267)	(1,259)
Allowance for funds used during construction	**350**	161	101
Non-controlling interests and other	**(156)**	(101)	(66)
	2,188	2,339	2,426
Average exchange rate – U.S. to Canadian dollars	**1.35**	1.30	1.25

1 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 and Foreign exchange (gains) losses, net 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. On January 17, 2023, a wholly-owned Mexican subsidiary entered into a US$1.8 billion senior unsecured term loan and a US$500 million senior unsecured revolving credit facility with a third party, which resulted in an additional peso-denominated income tax expense compared to 2022.

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, 2023	**16.91**
December 31, 2022	19.50
December 31, 2021	20.48

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 $)	**2023**	**2022**	**2021**
Comparable EBITDA – Mexico Natural Gas Pipelines[1]	**(83)**	(32)	1
Foreign exchange gains (losses), net included in comparable earnings	**224**	54	15
Income tax (expense) recovery included in comparable earnings	**(133)**	(11)	4
	8	11	20

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.

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 operations, access to capital markets, portfolio management activities, joint ventures, asset-level financing, cash on hand and substantial committed credit facilities. Annually, in fourth quarter, we renew and extend our credit facilities as required.

Financial Plan

Our capital program is comprised of approximately $31 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 including:

- senior debt
- hybrid securities
- preferred shares
- asset divestitures
- 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

At December 31, 2023, our current assets totaled $11.4 billion and current liabilities amounted to $11.8 billion, leaving us with a working capital deficit of $0.4 billion compared to $9.6 billion at December 31, 2022. The change in working capital is primarily due to proceeds received from the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf, which also resulted in the reduction of short-term borrowings. 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 $9.6 billion of committed revolving credit facilities available for short-term borrowing capacity, of which no amounts have been drawn. We also have arrangements in place for a further $2.0 billion of demand credit facilities on which $1.0 billion remains available as of December 31, 2023
- additional $1.5 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, our asset divestiture program and DRP, if deemed appropriate.

Our total assets at December 31, 2023 were $125.0 billion compared to $114.3 billion at December 31, 2022 with the increase primarily reflecting our capital spending program, working capital, increased equity investments, partially offset by depreciation and a weaker U.S. dollar at December 31, 2023 compared to December 31, 2022 on translation of our U.S. dollar-denominated assets.

At December 31, 2023 our total liabilities were $86.0 billion, compared to $80.2 billion at December 31, 2022 due to the net effect of movements in debt, working capital and a weaker U.S. dollar at December 31, 2023 compared to December 31, 2022 on translation of our U.S. dollar-denominated liabilities.

Our equity at December 31, 2023 was $39.0 billion compared to $34.1 billion at December 31, 2022. The increase is primarily due to the sale of a 40 per cent non-controlling equity interest in Columbia Gulf and Columbia Gas, partially offset by net income, net of common and preferred dividends paid, and lower other comprehensive income.

Consolidated capital structure

The following table summarizes the components of our capital structure.

at December 31 (millions of $, unless otherwise noted)	2023	Per cent of total	2022	Per cent of total
Notes payable	**—**	**—**	6,262	7
Long-term debt, including current portion	**52,914**	**54**	41,543	45
Cash and cash equivalents	**(3,678)**	**(4)**	(620)	(1)
	49,236	**50**	47,185	51
Junior subordinated notes	**10,287**	**10**	10,495	11
Preferred shares	**2,499**	**3**	2,499	3
Common shareholders' equity	**27,054**	**27**	31,491	35
Non-controlling interests	**9,455**	**10**	126	—
	98,531	**100**	91,796	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, 2023.

Cash flows

The following tables summarize our consolidated cash flows.

year ended December 31 (millions of $)	2023	2022	2021
Net cash provided by operations	**7,268**	6,375	6,890
Net cash (used in) provided by investing activities	**(12,287)**	(7,009)	(7,712)
Net cash (used in) provided by financing activities	**8,093**	487	(88)
	3,074	(147)	(910)
Effect of foreign exchange rate changes on cash and cash equivalents	**(16)**	94	53
Increase (decrease) in cash and cash equivalents	**3,058**	(53)	(857)

Cash provided by operating activities

year ended December 31 (millions of $)	2023	2022	2021
Net cash provided by operations	**7,268**	6,375	6,890
Increase (decrease) in operating working capital	**(207)**	639	287
Funds generated from operations	**7,061**	7,014	7,177
Specific items:			
Current income tax expense on disposition of equity interest[1]	**736**	—	—
Focus Project costs, net of current income tax	**54**	—	—
Keystone regulatory decisions, net of current income tax	**53**	27	—
Liquids Pipelines business separation costs	**40**	—	—
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	40
Current income tax expense on Keystone XL asset impairment charge and other	**(14)**	96	140
Voluntary Retirement Program, net of current income tax	**—**	—	49
Comparable funds generated from operations	**7,980**	7,353	7,406

1 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 $893 million in 2023 compared to 2022 primarily due to the amount and timing of working capital changes and higher funds generated from operations.

Net cash provided by operations decreased by $515 million in 2022 compared to 2021 primarily due to the amount and timing of working capital changes and lower funds generated from operations.

Comparable funds generated from operations

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

Comparable funds generated from operations increased by $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.

Comparable funds generated from operations decreased by $53 million in 2022 compared to 2021 primarily due to higher interest expense and net realized losses on derivatives used to manage our foreign exchange exposures, partially offset by higher comparable EBITDA.

Cash (used in) provided by investing activities

year ended December 31 (millions of $)	2023	2022	2021
Capital spending			
Capital expenditures	**(8,007)**	(6,678)	(5,924)
Capital projects in development	**(142)**	(49)	—
Contributions to equity investments	**(4,149)**	(2,234)	(1,210)
	(12,298)	(8,961)	(7,134)
Acquisitions, net of cash acquired	**(307)**	—	—
Loans to affiliate (issued) repaid, net	**250**	(11)	(239)
Keystone XL contractual recoveries	**10**	571	—
Proceeds from sales of assets, net of transaction costs	**33**	—	35
Other distributions from equity investments	**23**	1,433	73
Deferred amounts and other	**2**	(41)	(447)
Net cash (used in) provided by investing activities	**(12,287)**	(7,009)	(7,712)

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.

Net cash used in investing activities decreased from $7.7 billion in 2021 to $7.0 billion in 2022 largely as a result of higher other distributions from our equity investments primarily related to our proportionate share of the Sur de Texas debt repayment, contractual recoveries received in 2022 with respect to the Keystone XL pipeline project termination in 2021, as well as a loan issued to one of our affiliates in 2021, partially offset by higher capital spending in 2022.

Capital spending[1]

The following table summarizes capital spending by segment.

year ended December 31 (millions of $)	2023	2022	2021
Canadian Natural Gas Pipelines	**6,184**	4,719	2,737
U.S. Natural Gas Pipelines	**2,660**	2,137	2,820
Mexico Natural Gas Pipelines	**2,292**	1,027	129
Liquids Pipelines	**49**	143	571
Power and Energy Solutions	**1,080**	894	842
Corporate	**33**	41	35
	12,298	8,961	7,134

1 Capital spending reflects cash flows associated with our Capital expenditures, Capital projects in development and Contributions to equity investments. Refer to Note 5, Segmented information, of our 2023 Consolidated financial statements for the financial statement line items that comprise total capital spending.

Capital expenditures
Capital expenditures in 2023 were incurred primarily for the advancement of the Southeast Gateway pipeline, the NGTL System expansion and NGTL System/Foothills West Path Delivery programs, Columbia Gas and ANR projects, as well as maintenance capital expenditures. Higher capital expenditures in 2023 compared to 2022 reflect spending for the advancement of the Southeast Gateway pipeline, Gillis Access and Columbia Gas projects, partially offset by reduced spending on expansion of the NGTL System.

Capital projects in development
Costs incurred during 2023 on Capital projects in development were attributable to spending on projects in the Power and Energy Solutions segment.

Contributions to equity investments
Contributions to equity investments 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 are accounted for as in-substance equity contributions.

Contributions to equity investments increased in 2022 compared to 2021 mainly due to the partner equity contribution of approximately $1.3 billion made in 2022 to Coastal GasLink LP in accordance with revised agreements impacting Coastal GasLink LP. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information. This was partially offset by lower contributions made to Iroquois in 2021.

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.

Acquisitions
On March 15, 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. On June 14, 2023, we 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. Refer to the Significant Events – Power and Energy Solutions section for additional information.

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.

Keystone XL contractual recoveries
In 2023, we received $10 million (2022 – $571 million) of contractual recoveries with respect to the Keystone XL pipeline project termination in 2021.

Proceeds from sales of assets
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).

In 2021, we completed the sale of our remaining 15 per cent equity interest in Northern Courier for gross proceeds of $35 million.

Other distributions from equity investments
Other distributions from equity investments primarily relate to our proportionate share of the Sur de Texas debt repayments in 2022 and 2021, as well as the return of capital from our equity investment in Iroquois in 2023 and 2022.

Subsequent to the refinancing activities with the Sur de Texas 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.

Cash (used in) provided by financing activities

year ended December 31 (millions of $)	2023	2022	2021
Notes payable issued (repaid), net	**(6,299)**	766	1,003
Long-term debt issued, net of issue costs	**15,884**	2,508	10,730
Long-term debt repaid	**(3,772)**	(1,338)	(7,758)
Disposition of equity interest, net of transaction costs	**5,328**	—	—
Junior subordinated notes issued, net of issue costs	**—**	1,008	495
Redeemable non-controlling interest repurchased	**—**	—	(633)
Dividends and distributions paid	**(3,052)**	(3,385)	(3,548)
Common shares issued, net of issue costs	**4**	1,905	148
Preferred shares redeemed	**—**	(1,000)	(500)
Gains (losses) on settlement of financial instruments	**—**	23	(10)
Acquisition of TC PipeLines, LP transaction costs	**—**	—	(15)
Net cash (used in) provided by financing activities	**8,093**	487	(88)

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. Refer to the U.S. Natural Gas Pipelines – Significant events section for additional information.

Net cash provided by financing activities increased by $0.6 billion in 2022 compared to 2021 primarily due to highe proceeds from common shares and junior subordinated notes issued in 2022, as well as the 2021 subsequent repurchase of the redeemable non-controlling interest from contributions received in 2020 in support of Keystone XL construction, partially offset by lower net issuances of long-term debt and notes payable along with higher preferred shares redemption.

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 2023.

(millions of Canadian $, unless otherwise noted)					
Company	**Issue date**	**Type**	**Maturity date**	**Amount**	**Interest rate**
TRANSCANADA PIPELINES LIMITED					
	May 2023	Senior Unsecured Term Loan[1]	May 2026	US 1,024	Floating
	March 2023	Senior Unsecured Notes	March 2026[2]	US 850	6.20 %
	March 2023	Senior Unsecured Notes	March 2026[2]	US 400	Floating
	March 2023	Medium Term Notes	July 2030	1,250	5.28 %
	March 2023	Medium Term Notes	March 2026[2]	600	5.42 %
	March 2023	Medium Term Notes	March 2026[2]	400	Floating
COLUMBIA PIPELINES OPERATING COMPANY LLC[3]					
	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[3]					
	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

1 This loan was fully repaid and retired in September 2023. Related unamortized debt issue costs of $3 million were included in Interest expense in the Consolidated statement of income.

2 Callable at par in March 2024 or at any time thereafter.

3 On October 4, 2023, TC Energy completed the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf. Refer to Note 24, Non-controlling interests, of our 2023 Consolidated financial statements for additional information.

On January 9, 2024, Columbia Pipelines Holding Company LLC issued US$500 million senior unsecured notes due January 2034, bearing interest at a fixed rate of 5.68 per cent.

Long-term debt repaid/retired

The following table outlines significant long-term debt repaid/retired in 2023.

(millions of Canadian $, unless otherwise noted)				
Company	**Retirement date**	**Type**	**Amount**	**Interest rate**
TRANSCANADA PIPELINES LIMITED				
	October 2023	Senior Unsecured Notes	US 625	3.75 %
	September 2023	Senior Unsecured Term Loan[1]	US 1,024	Floating
	July 2023	Medium Term Notes	750	3.69 %
TUSCARORA GAS TRANSMISSION COMPANY				
	November 2023	Unsecured Term Loan	US 32	Floating
NOVA GAS TRANSMISSION LTD.				
	April 2023	Debentures	US 200	7.88 %
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.				
	Various	Senior Unsecured Revolving Credit Facility	US 315	Floating

1 In May 2023, we entered into a US$1,024 million senior unsecured term loan and the full amount was drawn. The loan was fully repaid and retired in September 2023. Related unamortized debt issue costs of $3 million were included in Interest expense in the Consolidated statement of income.

For more information about long-term debt and junior subordinated notes issued and long-term debt repaid in 2023, 2022 and 2021, refer to the notes to our 2023 Consolidated financial statements.

Redeemable non-controlling interest repurchased

On January 8, 2021, we exercised our call right in accordance with contractual terms and paid US$497 million ($633 million) to repurchase the Government of Alberta Class A Interests which were classified as Current liabilities on the Consolidated balance sheet at December 31, 2020. This transaction was funded by draws on the Keystone XL project-level credit facility.

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. The participation rate by common shareholders in the DRP in 2023 was approximately 39 per cent (2022 – 33 per cent), resulting in $737 million (2022 – $607 million) reinvested in common equity under the program.

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 9, 2024		
Common Shares	**issued and outstanding**	
	1.0 billion	
Preferred Shares	**issued and outstanding**	**convertible to**
Series 1	14.6 million	Series 2 preferred shares
Series 2	7.4 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	18 million	Series 10 preferred shares
Series 11	10 million	Series 12 preferred shares
Options to buy common shares	**outstanding**	**exercisable**
	7 million	4 million

For more information on preferred shares refer to the notes to our 2023 Consolidated financial statements.

Dividends

year ended December 31	2023	2022	2021
Dividends declared			
per common share	$3.72	$3.60	$3.48
per Series 1 preferred share	$0.86975	$0.86975	$0.86975
per Series 2 preferred share	$1.62659	$0.82611	$0.50997
per Series 3 preferred share	$0.4235	$0.4235	$0.4235
per Series 4 preferred share	$1.46703	$0.66655	$0.34997
per Series 5 preferred share	$0.48725	$0.48725	$0.48725
per Series 6 preferred share	$1.55993	$0.80668	$0.41622
per Series 7 preferred share	$0.97575	$0.97575	$0.97575
per Series 9 preferred share	$0.9405	$0.9405	$0.9405
per Series 11 preferred share	$0.83775	$0.83775	$0.83775
per Series 13 preferred share	—	—	$0.34375
per Series 15 preferred share	—	$0.30625	$1.225

On February 13, 2024, we increased the quarterly dividend on our outstanding common shares by 3.2 per cent to $0.96 per common share for the quarter ending March 31, 2024 to shareholders of record at the close of business on March 28, 2024, which equates to an annual dividend of $3.84 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 9, 2024, we had a total of $11.8 billion of committed revolving and demand credit facilities, including:

(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 2028	3.0	2.8
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2024	US 2.5	US 2.3
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2026	US 2.5	US 2.5
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 [2]	1.0 [2]

1 Unused capacity is net of commercial paper outstanding and facility draws.
2 Or the U.S. dollar equivalent.

At February 9, 2024, our operated affiliates had an additional $1.5 billion of undrawn capacity on third-party demand and committed credit facilities.

Contractual obligations

Our contractual obligations include our long-term debt, operating leases, purchase obligations and other liabilities incurred in our business such as environmental liability funds and employee pension and post-retirement benefit plans.

Payments due (by period)

at December 31, 2023					
(millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Long-term debt and junior subordinated notes[1]	63,503	2,938	8,066	9,328	43,171
Operating leases[2]	548	72	134	117	225
Purchase obligations and other	4,988	2,649	813	517	1,009
	69,039	5,659	9,013	9,962	44,405

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.

Notes payable

Total notes payable outstanding at December 31, 2023 was nil (2022 – $6.3 billion).

Long-term debt and junior subordinated notes

At December 31, 2023, we had $52.9 billion (2022 – $41.5 billion) of long-term debt and $10.3 billion (2022 – $10.5 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.

Interest payments

At December 31, 2023, scheduled interest payments related to our long-term debt and junior subordinated notes were as follows:

at December 31, 2023					
(millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Long-term debt	25,439	2,373	4,323	3,612	15,131
Junior subordinated notes	50,734	611	1,318	1,678	47,127
	76,173	2,984	5,641	5,290	62,258

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 2024 to 2038, that require the purchase of generated energy and associated environmental attributes. At December 31, 2023, the total planned capacity secured under the PPAs is approximately 800 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.

Purchase obligations and other

At December 31, 2023, payments for purchase obligations and other were as follows:

at December 31, 2023 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Canadian Natural Gas Pipelines					
Transportation by others[1]	1,685	177	363	341	804
Capital spending[2]	226	197	20	7	2
U.S. Natural Gas Pipelines					
Transportation by others[1]	546	142	216	94	94
Capital spending[2]	340	314	26	—	—
Mexico Natural Gas Pipelines					
Capital spending[2]	1,312	1,312	—	—	—
Liquids Pipelines					
Transportation by others[1]	43	26	17	—	—
Capital spending[2]	6	6	—	—	—
Other	3	3	—	—	—
Power and Energy Solutions					
Capital spending[2]	231	200	31	—	—
Other[3]	187	22	28	28	109
Corporate					
Other	395	236	112	47	—
Capital spending[2]	14	14	—	—	—
	4,988	2,649	813	517	1,009

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

3 Includes estimates of certain amounts which are subject to change depending on plant-fired hours, the consumer price index, actual plant maintenance costs, plant salaries, as well as changes in regulated rates for fuel transportation.

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 2024, with the annual option to extend for one year periods ending in 2053.

At December 31, 2023, our share of potential exposure under the Sur de Texas pipeline guarantees was estimated to be $97 million with a carrying amount of less than $1 million.

Bruce Power

We and our joint venture partner on Bruce Power, BPC Generation Infrastructue 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 2025 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, 2023, 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, construction services including purchase agreements and the payment of liabilities. The guarantees have terms ranging to 2043.

Our share of the potential exposure under these assurances was estimated at December 31, 2023 to be approximately $80 million with a carrying amount of $3 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 2023, we made funding contributions of $28 million to our defined benefit pension plans, $9 million for other post-retirement benefit plans and $64 million for the savings plan and defined contribution plans. Total letters of credit provided for the funding of solvency requirements to the Canadian defined benefit plan at December 31, 2023 was $244 million (2022 – $322 million; 2021 – $322 million).

In 2024, we expect to make no contributions for the defined benefits pension plans, funding contributions of approximately $6 million for other post-retirement benefit plans and approximately $70 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 defined benefit and other post-retirement plans decreased to $20 million in 2023 from $57 million in 2022 primarily due to the impact of increased interest rates.

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.

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 is to ensure that our risks and related exposures are aligned with our business objectives and risk tolerances. We manage risk through a centralized Enterprise Risk Management (ERM) program that systematically identifies enterprise risks, including sustainability-related risks, which could materially impact the achievement of our strategic objectives.

The purpose of the ERM program is to address risks to, or yielding from, the execution of our business strategies, as well as enabling practices that allow us to identify and monitor emerging risks. Specifically, the ERM program and framework provides an end-to-end process for risk identification, analysis, evaluation and mitigation, and the ongoing monitoring and reporting to the Board, CEO and Executive Vice-Presidents, including the Chief Risk Officer.

Our Board retains general oversight of all enterprise risks, as identified below, and specifically has direct oversight of reputation and relationships, political and regulatory uncertainty, capital allocation strategy, project execution and capital costs. The Board reviews the enterprise risk register annually and is informed quarterly on emerging risks and how these risks are being managed and mitigated in accordance with TC Energy's risk appetite and tolerances. It also participates in detailed presentations on each enterprise risk identified in the enterprise risk register as required or requested.

Our Board of Directors' Governance Committee oversees the ERM program, ensuring appropriate oversight of our risk management activities. Other Board committees oversee specific types of risk, including sustainability-related risks, within their mandate. More specifically:

- 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 managing financial risk, including market risk, counterparty credit risk and cybersecurity.

Our executive leadership team is accountable for developing and implementing risk management plans and actions, and effective risk management is reflected in their compensation. Each identified enterprise risk has an executive leadership team member as the governance and execution owner who provides an in-depth review for the Board on an annual basis.

Key segment-specific financial, health, safety and environment risks are covered in their respective sections of this MD&A. Further, our management of climate-related governance, strategy, risks and opportunities, metrics and targets are outlined in our comprehensive TCFD alignment section of our Report on Sustainability. A summary of enterprise-wide risks with potential to impact our strategic objectives can be found below. These risks are being continuously monitored through our robust ERM program, which includes a network of emerging risk liaisons in key positions across the organization who are responsible for identifying potential enterprise-level risks that are reported quarterly to the Board of Directors.

As part of our commitment to continuous improvement of the ERM program, we identified and are working towards adopting Key Risk Indicators (KRIs) for risk events that may impact our ability to achieve our strategic objectives. These metrics will establish a set of appropriate indicators that will provide quantifiable metrics and objective rationale, as well as meaningful trending, for each enterprise risk. Going forward, KRIs will be used to inform our annual in-depth review of our enterprise risks conducted by the Board.

Risk and description	Impact	Monitoring and mitigation
Business interruption		
Operational risks, including equipment malfunctions and breakdowns, labour disputes, pandemic and other catastrophic events including those related to climate change, acts of terror, sabotage and third-party excavations on our right of way.	Decrease in revenues and increase in operating costs, legal proceedings or regulatory actions, or other expenses, all of which could reduce our earnings. Losses not recoverable through tolls, contracts or insurance could have an adverse effect on operations, cash flows and financial position. Certain events could lead to risk of injury or fatality, property and environmental damage.	Our management system, TOMS, provides structured requirements and processes for our day-to-day work to protect us, our co-workers, our workplace and assets, the communities we work in and the environment. TOMS establishes operational risk management practices to minimize risk exposure and operational failures and is continually improved based on new knowledge from performance monitoring of our assets, learnings from external incidents and collaborative work with industry and regulators. TOMS includes process safety, incident, emergency and crisis management programs to ensure TC Energy can effectively respond to operational events, minimize loss or injury and enhance our ability to resume operations. This is supported by our business continuity program that identifies critical business processes and develops corresponding business resumption plans. Although we have a comprehensive insurance program to mitigate a certain portion of our risk, insurance does not cover all events in all circumstances.
Cybersecurity		
We rely on our information technology to process, transmit and store electronic information, including information we use to safely operate our assets. We continue to face cybersecurity risks and could be subject to cybersecurity events directed against our information technology or physical assets. This risk has been elevated with the increased pace of technology adoption, as well as evolving geopolitical conflicts. The methods used to obtain unauthorized access, disable or degrade service or sabotage systems are constantly evolving and may be difficult to anticipate or to detect, bringing novel or unexpected vulnerabilities. This has resulted in stricter cybersecurity regulations in the jurisdictions in which we operate.	A cyberattack could expose our business to a wide range of losses, including misuse or interruption of critical information and functions. It could also affect our operations by damaging our assets, resulting in potential safety and/or environmental incidents. A significant attack could also cause reputational harm, competitive disadvantage, regulatory enforcement actions and potential litigation, which could have a material adverse effect on our operations and/or financial position.	We maintain a comprehensive cybersecurity strategy and program which aligns with regulatory and industry standards. Our strategy is regularly reviewed and updated, and the status of our cybersecurity program is reported to the Audit Committee on a quarterly basis. The program includes governance covered by policies and standards, risk assessments, continuous monitoring of networks and other information sources for threats to the organization, comprehensive incident response plans/processes and a robust cybersecurity awareness program for employees and contractors. We have insurance which may cover losses from physical damage to our facilities as a result of a cybersecurity event; however, insurance does not cover all events in all circumstances.
Reputation and relationships		
Our operations and growth prospects require us to have strong relationships with key stakeholders including customers, Indigenous communities, landowners, suppliers, investors, governments, government agencies and environmental non-governmental organizations.	Inadequately managing stakeholder expectations and concerns, including those related to climate and sustainability, can have a significant impact on our operations and projects, infrastructure development and overall reputation. It could also affect our ability to operate and grow.	Our core values – safety, innovation, responsibility, collaboration and integrity – guide us in building and maintaining our key relationships, as well as our interactions with stakeholders. We are proud of the strong relationships we have built with stakeholders across our geographies, and we are continuously seeking ways to strengthen these relationships. Beyond our core values, we have specific stakeholder programs and policies that shape our interactions, clarify expectations, assess risks and facilitate mutually beneficial outcomes. Further, our management of climate-related governance, strategy, risks and opportunities, metrics and targets are outlined in our annual Report on Sustainability.

Risk and description	Impact	Monitoring and mitigation
Political and regulatory uncertainty		
Our ability to construct and operate energy infrastructure requires regulatory approvals and is dependent on evolving policies and regulations by federal, state, provincial and local government agencies. This includes changes in regulation that may impact our projects and operations into the future, which could affect the financial performance of our assets.	Adverse impacts on competitive geographic and business positions could result in the inability to meet our growth targets through missed or lost organic, greenfield and brownfield opportunities. Financial impacts of denied or delayed projects could include lost development costs, loss of investor confidence and potential legal costs from litigation. Regulations could also increase the cost of our operations, due to complying with new or more stringent regulations, resulting in the inability to earn a reasonable return on our invested capital.	We monitor regulatory and government developments and decisions to analyze their possible impact on our businesses. We build scenario analysis into our strategic outlook and work closely with our stakeholders in the development and operation of our assets. We identify emerging risks including customer, regulatory and government decisions, as well as innovative technology development and report to our management of these risks quarterly through the ERM program to the Board. We also use this information to inform our capital allocation strategy and adapt to changing market conditions.
Access to capital at a competitive cost		
We require substantial amounts of capital in the form of debt and equity to finance our portfolio of growth projects and maturing debt obligations at costs that are sufficiently lower than the returns on our investments. Significant deterioration in market conditions for an extended period and changes in investor and lender sentiment could affect our ability to access capital at a competitive cost. Geopolitical instability, higher interest rates, and persistent inflation could put further pressures on the cost of capital into the future.	A higher cost of capital could negatively impact our ability to deliver an attractive return on our investments or inhibit both short and long-term growth. Significant increases to interest rates could result in a higher cost of borrowing and therefore negatively impact our earnings.	We operate within our financial means and risk tolerances, maintain a diverse array of funding levers and also utilize asset divestitures as a component of our financing program. In addition, we have candid and proactive engagement with the investment community, including credit rating agencies, with the objective of hearing their feedback and keeping them apprised of developments in our business and factually communicating our prospects, risks and challenges, as well as sustainability-related updates. Sustainability remains a key consideration in determining strategy, capital allocation and engagement with capital markets. We conduct research annually around the evolving sustainability preferences of our investors and financial partners which we consider in our decision making.
Capital allocation strategy		
To be competitive, we must offer integral energy infrastructure services in supply and demand areas, and in forms of energy that are attractive to customers. We continue to adapt our strategy to protect and enhance the incumbency of our businesses.	Should alternative lower-carbon forms of energy result in decreased demand for our services on an accelerated timeline versus our pace of depreciation, the value of our long-lived energy infrastructure assets could be negatively impacted.	We have a diverse portfolio of assets and use portfolio management to effectively rotate capital while adhering to our risk preferences and focus on per share metrics. We conduct analyses to confirm the longer-term resilience of the supply and demand markets we serve as part of our energy fundamentals and strategic development reviews. We recover depreciation through our regulated pipeline rates which is an important lever to accelerate or decelerate the return of capital from a substantial portion of our assets. We also monitor signposts including customer, regulatory and government decisions, as well as innovative technology development to inform our capital allocation strategy to respond to changing market conditions.
Project execution and capital costs		
Investing in large infrastructure projects involves substantial capital commitments and associated execution risks, including skilled labour shortages and weather-related delays, which can impact project costs and schedules, based on the assumption that these assets will deliver an attractive return on investment in the future.	While we carefully determine the expected cost of our capital projects, under some commercial arrangements, we bear capital cost overrun and schedule risk which may decrease our return on these projects.	Our Project Governance program supports project execution and operational excellence. The program aligns with TOMS which provides the framework and standards to optimize project execution, supporting timely and on budget completion. We prefer to contractually structure our projects to recover development costs if a project does not proceed along with mechanisms to minimize the impact should cost overruns occur. However, under some commercial arrangements, we share or bear the cost of execution risk. Additionally, we can utilize project financing and/or involve partners in our projects to manage capital at risk.

Risk and description	Impact	Monitoring and mitigation
Talent attraction, retention, and succession planning		
Critical skills are required to execute our strategy which include a deep understanding of the energy industry, geopolitical environment and various regulatory regimes in the areas we operate. The talent landscape is undergoing high degrees of change necessitating adaptation, flexibility and constant monitoring of enterprise-wide talent strategies.	Talent challenges could significantly impact the organization through increased costs, decreased productivity, and the ability to effectively compete in the marketplace. It could also result in a failure to achieve our strategic objectives.	We assess our talent risk using a framework based on people data and trends, which we examine for level of criticality. We use the outcome of this assessment to determine which talent programs will yield the best results to attract, retain and develop talent. Plans to enhance our workforce planning initiatives are underway.

Climate change

Physical and transition risks associated with climate change have the potential to intensify the enterprise risks outlined above. Our business, operations, financial condition and performance may be impacted by climate change policies and its associated impacts. We report and monitor material climate policy and related developments through our ERM program to ensure Management and our Board of Directors have visibility to the broader perspective, and that mitigation plans are applied in a holistic and consistent manner.

Physical Risks

Physical risks to assets could include, but are not limited to severe weather events, wildfires, and longer-term shifts in climate patterns, temperature and precipitation; however, it is difficult to predict the timing, frequency, or severity of such events. Physical risks from climate change could carry financial implications, such as costs resulting from direct damage to our assets, loss of revenues due to business interruption or indirect effects such as value chain disruption. We may experience increased insurance premiums and deductibles, or a decrease in available coverage, for our assets in areas subject to severe weather.

Our engineering standards are regularly reviewed to ensure assets continue to be designed and operated to withstand the potential impacts of climate change. Our emergency response plans are focused on quickly and effectively responding to emergencies and mitigating impacts in a timely manner. We also maintain insurance as a mitigative measure to reduce the financial impact associated with damage to our assets due to extreme weather events.

Transition Risks

Transition risks arise as a result of the global shift to a more sustainable, lower GHG emissions 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 GHG emissions intensive economy. Financial implications from transition risks could include asset impairment due to new or amended climate-related regulations, increased climate change reporting requirements, increased commodity price volatility, 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 and the development and deployment of new technology.

Our exposure to climate change related transition risk and resulting policy changes is managed through our business model, which is based on a long-term, low-risk strategy whereby much of our earnings are underpinned by regulated cost-of-service arrangements and/or long-term contracts. We factor transition risks into our capital planning, financial risk management and operational activities and are working towards reducing the GHG emissions intensity of our existing operations.

We also evaluate the financial resilience of our asset portfolio against a range of future outcomes as part of our strategic planning process. We are exploring technologies, implementing strategies, and incorporating our GHG emissions reduction targets in our capital allocation framework and decision-making process.

Information on how we manage climate-related risks and opportunities can be found in our annual Report on Sustainability.

Health, safety, sustainability and environment

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

TC Energy's Operational Management System, TOMS, leverages industry best practices and standards and incorporates applicable regulatory requirements. TOMS governs health, safety, environment, and operational integrity matters at TC Energy. It is applicable across Canada, U.S. and Mexico throughout the lifecycle of our assets and employs a continuous improvement cycle. Periodic audits of TOMS, as they apply to our Canadian assets, are conducted by the CER and lessons learned from these audits are shared and applied across our system where applicable.

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 change related risks and opportunities, as well as related voluntary public disclosure such as our Report on Sustainability and the Reconciliation Action Plan.

To enhance our overall governance structure, we have evolved our corporate HSSE committee into two separate committees that report to the Board HSSE Committee:

- a Sustainability Management Committee that provides strategic leadership and direction on sustainability issues
- an Operating Committee that is responsible for making enterprise decisions in support of management system governance, strategic system enhancements and operational risk management related to safety and environmental considerations.

Focus on sustainability

Starting in 2022, we embedded sustainability goals into our corporate scorecard to progress and advance key strategic priorities including growth and energy transition. Our 2023 corporate scorecard includes goals on safety, diversity of women and visible minorities in leadership and management of our GHG emissions. Our approach to sustainability is guided by our nine commitments that align to the United Nations (UN) Sustainable Development Goals, with tangible targets to measure and drive performance in areas including emissions reductions, women in leadership, biodiversity and safety. We are committed to ensuring balanced and transparent disclosure of our progress against these targets annually in our Report on Sustainability.

Another way in which we demonstrate our commitment to sustainability is through our pursuit of voluntary initiatives. In May 2023, we joined Catalyst, a global non-profit organization supporting companies with solutions and strategies to accelerate progress for women through workplace inclusion. In June 2023, we completed a pilot of the Taskforce for Nature-based Financial Disclosures framework to support the development of an approach to disclosure of nature-related dependencies, impacts, risks and opportunities. In July 2023, we signed the UN Women's Empowerment Principles (WEPs), furthering our commitment to foster an inclusive, safe and productive workplace for all our staff. By signing the WEPs, we are committing to align with the seven core principles and take steps to advance gender equality in our workplace and community.

Our Reconciliation Action Plan, including the 2022 update, outlines six measurable goals of action to help advance reconciliation, both internally and in the communities where we operate. Throughout 2023, our Indigenous Advisory Council, established with members representing Indigenous perspectives across Canada, has advised on strategies, approaches, and tactics in support of pillar areas of focus including: talent and employment, hiring and contracting, and relationships and partnerships.

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 2023, we spent $2.1 billion (2022 – $1.6 billion) for pipeline integrity on the natural gas and liquids 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. Similarly, under our Keystone Pipeline System contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, 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 Management Program 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.

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, including crude oil, diluent and natural gas, 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 or in connection with environmental protection.

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, 2023, accruals related to these obligations, with the exception of the accrual related to the Milepost 14 incident, totaled $19 million (2022 – $20 million) representing the estimated amount we will need to manage our currently known material environmental liabilities. Refer to the Liquids Pipelines – Significant events section for additional information. 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 2023, we incurred $109 million (2022 – $118 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 and submit comments to regulators as these new and evolving initiatives are undertaken and policies are implemented. We support transparent climate change policies that promote sustainable and economically responsible natural resource development. Our assets in specific geographies are currently subject to GHG regulations and 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 changing 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:* ECCC's methane reduction regulations that detail requirements to reduce methane emissions through operational and capital modifications came into effect in January 2020. ECCC's methane reduction regulation aims to reduce the oil and gas sector emissions by 40 to 45 per cent below 2012 levels by 2025. Alberta, British Columbia and Saskatchewan have drafted their own methane regulations that take the place of the federal regulation for provincially-regulated assets. For federally-regulated facilities in these jurisdictions, the federal methane regulation is applicable. Compliance with the regulations requires an increased level of leak detection and repair (LDAR) surveys, repairs to identified leaking equipment components following prescribed timelines and measurements to quantify emission reductions. Power facilities are not affected by this regulation at the current time
- *Federal:* The Government of Canada has developed the Clean Fuel Regulations (CFR) to achieve reductions in GHG emissions with a narrowed scope including only liquid fuels, which will not directly impact TC Energy. CFR does allow for credit generation opportunities for gaseous fuel stream to incentivize GHG emission reduction opportunities. The CFR was finalized in June 2022 and came into effect in July 2023. Regulated parties and credit generators expressed concerns over uncertainties about credit availability and recognition for the 2023 and 2024 periods, stemming from ongoing updates like the incomplete Land Use and Biodiversity Guidance and the anticipated ECCC Life Cycle Assessment model update in July 2024. Amidst these updates, there are concerns about the timely processing of Carbon Intensity applications, the limited number of CFR-accredited verification bodies, and the overall clarity regarding key elements for the successful implementation of the CFR. We continue to closely monitor this file and engage with Canadian policymakers, assessing impacts as further information is available
- *Federal:* The Federal OBPS regulation imposes carbon pricing for larger industrial facilities and sets federal benchmarks for GHG emissions for various industry sectors. This federal regulation is currently in effect in the province of 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 in tolls. The current level of carbon pricing is $65/tonne, increasing by $15/tonne every year to $170/tonne in 2030
- *Federal:* New requirements for federally regulated project applications under the Impact Assessment Agency were introduced through the Strategic Assessment of Climate Change, requiring a project proponent to provide a credible plan for a proposed project to achieve net-zero emissions by 2050. The CER published a revision to its Filing Manual to integrate the Strategic Assessment of Climate Change, which includes a requirement that projects regulated by the CER with a lifetime beyond 2050 must also include a credible plan to achieve net-zero emissions by 2050. Responses to this requirement are being developed and provided as part of the project applications on a case-by-case basis
- *British Columbia:* British Columbia implemented a tax on GHG emissions from fossil fuel combustion. While we are subject to this tax, the compliance costs are recovered through tolls. Additionally, British Columbia established the CleanBC program which provides incentive payments or tax rebates for industrial operations that meet an established emission intensity benchmark. The CleanBC Industry Fund directs a portion of the carbon tax paid by industry to fund incentives for cleaner operations by means of performance benchmarking or funding emissions reduction projects
- *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 the majority of Bécancour's compliance requirements. The remaining requirements were 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 in order to comply with the requirements of this initiative with these compliance costs being recovered through tolls

- *Ontario:* The Ontario and Federal governments reached an agreement whereby 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:* In September 2022, the Saskatchewan and Federal governments reached an agreement whereby the Federal OBPS in Saskatchewan was replaced on January 1, 2023 by the Saskatchewan Emissions Performance Standards (SEPS) program for pipeline transmission sector assets. The SEPS apply 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 6, 2022 (OOOOb) and establishes emission guidelines (EGs) for existing sources prior to December 6, 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 of the rule are still subject to further evaluation and assessment, and actual compliance deadlines for existing sources will vary based on state and/or location
- *Federal*: Final "Good Neighbor Plan" for Ozone National Ambient Air Quality Standards. The USEPA released a final version of the Good Neighbor Rule on March 15, 2023, effective August 4, 2023, that specifies new limits for emissions of nitrogen oxides (NOx) from reciprocating internal combustion engines by May 1, 2026. Based on assessments completed thus far, the final rule could require installation of catalytic controls or retrofit of engines with low emission combustion controls at a cost exceeding US$500 million. However, seven Federal Circuit courts have granted stays of the Rule within their jurisdictions until decisions are made on the merits in those proceedings[1] and an emergency stay request remains pending before the U.S. Supreme Court
- *California:* Tuscarora facilities are subject to the California Air Resources Board's LDAR program requiring owners/operators of oil and gas facilities to monitor and repair methane leaks. Beginning in January 2020, thresholds for leak repair under this program were reduced. 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
- *Pennsylvania:* The Pennsylvania Department of Environmental Protection has an LDAR program for new source installations which require leak repair within 15 days of discovery
- *Pennsylvania:* In April 2022, the Pennsylvania Department of Environmental Protection (PADEP) published its final Reasonable Available Control Technologies (RACT) requirements and emission limitations for major stationary sources of NOx and volatile organic compounds (VOCs) statewide. Columbia Gas Transmission has four facilities impacted by the rule, and initial notifications and case by case evaluations were submitted to PADEP for these facilities by December 31, 2022. The purpose of the case-by-case evaluations was to determine whether sources could be re-permitted to the lower emission rate or if installation of controls would be necessary to comply. Columbia Gas Transmission facilities were able to re-permit to the lower emission rate based on historic stack test data such that no control installations were needed to comply
- *Ohio:* Effective March 2022, the Ohio Environmental Protection Agency (OEPA) finalized 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

[1] The seven circuit courts that have granted judicial stays for the entirety of litigation are as follows: 4th Circuit (West Virginia), 5th Circuit (Texas, Louisiana, Mississippi), 6th Circuit (Kentucky), 8th Circuit (Arkansas, Missouri, Minnesota), 9th Circuit (Nevada), 10th Circuit (Oklahoma, Utah) and the 11th Circuit (Alabama).

- *Oregon:* The Governor of Oregon issued an executive order to reduce and regulate GHG emissions by establishing annual reduction goals, developing a new carbon cap and reduce program and enhancing clean fuel standards on January 1, 2022. The state Department of Environmental Quality recommended a final draft of the rule to the state Environmental Quality Commission (EQC) and the EQC approved the program which still exempts our facilities and their emissions
- *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 base compliance obligation for 2023
- *Washington:* The Washington Commercial Building Code passed a ban to limit the use of natural gas-powered furnaces and water heaters in all new commercial and residential properties with four stories or more, starting in July 2023
- *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; and reporting of pigging activities, as well as a baseline inventory for all assets in New York.

Mexico jurisdictions

- 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 GHGs 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. This law requires an annual submission of our emissions
- the Government of Mexico published a regulation 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
- 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 functions 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.

Anticipated policies

Canadian jurisdictions

- *Federal:* ECCC committed to expand on the current methane reduction regulations and released draft amendments in December 2023 to reduce Canada's 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 will seek clarifications and adjustments and, in collaboration with industry associations, will participate in the public consultation process. 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:* In December 2023, ECCC released a Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap that builds on a July 2022 discussion paper to contribute to 2030 climate goals and achieve net-zero by 2050. The framework proposes to implement a national cap-and-trade system to cap upstream and LNG sub-sector emissions between 35 per cent to 38 per cent below 2019 levels, with some compliance flexibility up to 20 per cent to 23 per cent below the same baseline year. Although transmission pipelines are excluded from the proposed regulatory framework, there is a possibility of cascading effects and unintended consequences. The draft regulations are expected to be released in mid-2024, with final publication in 2025. The regulations are expected to be phased in between 2026 and 2030. We will continue to monitor, assess, and provide feedback to ECCC on the proposed emissions cap, as appropriate
- *Federal*: On August 19, 2023, ECCC published the draft Clean Electricity Regulations (CERs), targeting a net-zero electricity system by 2035. The CERs, effective from January 1, 2025, mandate a GHG emissions intensity standard of 30 tonnes CO_2/GWh for fossil fuel power generation units with a capacity of 25 MW or more, though there are exemptions and limited compliance flexibilities. The draft regulations, enacted under the Canadian Environmental Protection Act, could potentially affect energy affordability and reliability and have a significant operational and financial impact to our business; as drafted, our current cogeneration fleet would be required to meet this new standard by 2035. Throughout the consultation process, we are actively engaging with the ECCC, providing feedback and collaborating with other industry stakeholders. We will continue monitoring and providing feedback to ECCC as this file progresses
- *British Columbia*: Currently, British Columbia is formulating a new carbon pricing model, the British Columbia OBPS. This system mirrors the federal OBPS system and is forecasted to reduce the carbon tax payments in the near future. However, the British Columbia OBPS proposes a considerably more stringent threshold compared to the federal OBPS or other analogous jurisdictions like the Alberta Technology Innovation and Emissions Reduction Regulations. The specifics of the British Columbia OBPS are still under deliberation and any costs associated with are expected to be recoverable through tolls. We are proactively observing the developments and offering our feedback. Concurrently, British Columbia is laying the groundwork for an oil and gas emission cap within the province. We are actively involved in these discussions, providing feedback pertinent to our operations in British Columbia, with a focus on concerns related to energy affordability and reliability.

U.S. jurisdictions

- *Federal:* The U.S. Senate passed the PHMSA reauthorization bill, the PIPES Act of 2020, which required PHSMA 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 current and proposed methane standards. The cost of compliance due to the proposed PHMSA regulations is expected to increase significantly due to new monitoring and repair requirements on the entire natural gas transmission system
- *Federal:* In May 2023, USEPA released amendments to the previously released June 2022 proposal regarding the GHG Reporting program that would go into effect on January 1, 2025 and be included in Reporting Year 2024 for GHG reporting due to the USEPA by March 31, 2025. This proposal includes reporting of a new reporting category (Subpart B – Energy Consumption) and revisions to global warming potentials. USEPA released another supplemental proposal in August 2023. This proposal includes reporting of additional emission sources such as reciprocating engine exhaust methane and centrifugal compressor dry seal venting; revisions to current emission factors for fugitive equipment leaks and pneumatic devices; and options to use facility specific measurements in place of emission factors for certain emission sources. These proposed revisions would be implemented with reports prepared for Reporting Year 2025 for GHG reporting due to the USEPA by March 31, 2026. TC Energy reports to the USEPA as required by the GHG Reporting rule (40 CFR 98)
- *Federal:* The Inflation Reduction Act (IRA) was passed and signed into law on August 16, 2022. The IRA instructs 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. 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 IRA 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 have been no fee impact to TC Energy based on 2021 or 2022 emissions. The IRA also instructs USEPA to revise Subpart W by August 2024 to ensure GHG reporting is based on empirical data

- *California:* Our assets may be affected by the Governor of California's executive order, issued in September 2020, requiring all new cars and light trucks sold in California to be emission-free by 2035 and heavy and medium trucks to be emission-free by 2045. The significance of the impact on our assets is still being evaluated
- *California:* California Air Resource Board is planning potential changes to their California Oil and Gas Methane Regulation that include requirements for monitoring plans, repairing leaks after being identified by satellites and changes that would align with USEPA's proposed emissions guidelines for existing sources. The California Air Resources Board posted a notice of public availability on November 2, 2023 for proposed amendments to Sub article 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. The amendments consolidated the Delay of Repair (DOR) provisions into a dedicated section and elaborated on the justification requirements for DOR requests. The proposed amendments if adopted would require development of an implementation plan for three affected facilities and training for operations personnel
- *Michigan:* The Michigan Department of Environment, Great Lakes and Energy is currently evaluating potential ozone control strategies for the southeast Michigan ozone non-attainment area and the interaction of methane and ozone, which may lead to the development of laws and regulations that affect TC Energy through impacted ANR and Great Lakes facilities in the state
- *New York:* On July 18, 2019, the Climate Leadership and Community Protection Act (Climate Act) was signed into law, requiring New York to reduce economy-wide GHG emissions by 40 per cent by 2030 and no less than 85 per cent by 2050 from 1990 levels. 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 will set an annual cap on the amount of GHG emissions that are permitted to be emitted in the state. The program is currently in the stakeholder engagement phase, with compliance aimed to commence in 2025. NYCI will potentially impact TC Energy owned/operated assets in New York, but impacts will be further evaluated once a draft rule is published, which is expected in 2024.

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. We are currently reviewing the proposed rule to determine its impact.

In addition to the 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

There are also mandatory cybersecurity and human rights-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 liquids marketing business, we enter into pipeline and storage terminal capacity contracts, as well as crude oil purchase and sale agreements. We fix a portion of our exposure on these contracts by entering into financial instruments to manage variable price fluctuations that arise from physical liquids transactions
- in our power businesses, 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, crude oil 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 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 from equity investments and Income tax expense.

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 and certain contractual recoveries
- 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, 2023 and 2022, we had no significant credit risk concentrations and no significant amounts past due or impaired. We recorded an $80 million recovery for the year ended December 31, 2023 on the expected credit loss provision before tax recognized on the TGNH net investment in leases and certain contract assets in Mexico (2022 – $163 million loss). Other than the expected credit loss provision noted above, we had no significant credit losses at December 31, 2023 and 2022. Refer to Note 29, Risk management and financial instruments, of our 2023 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. With the potential exception of the matters discussed in Note 32, Commitments, contingencies and guarantees, of our 2023 Consolidated financial statements, for which the claims are material and there is a reasonable possibility of loss, but have not been assessed as probable and a reasonable estimate of loss cannot be made, 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.

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, 2023, 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, 2023, 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, 2023, the internal control over financial reporting was effective.

Our internal control over financial reporting as of December 31, 2023 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included in our 2023 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 2023 reports filed with Canadian securities regulators and the SEC and have filed certifications with them.

Changes in internal control over financial reporting

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

CRITICAL ACCOUNTING ESTIMATES

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

Certain estimates and judgments have a material impact where the assumptions underlying these accounting estimates relate to matters that are highly uncertain at the time the estimate or judgment is made or are subjective. Refer to Note 2, Accounting policies, of our 2023 Consolidated financial statements for additional information.

Impairment of equity investment in Coastal GasLink LP

On February 1, 2023, TC Energy announced that the revised capital cost of the Coastal GasLink pipeline project was expected to be approximately $14.5 billion. The revised estimate of total project costs and our corresponding future funding requirements were indicators that a decrease in the value of our equity investment had occurred. A valuation assessment was completed at December 31, 2022 and at each reporting period through September 30, 2023 and we concluded that the fair value of TC Energy's investment was below its carrying value at each period an assessment was performed. We determined that there was an other-than-temporary impairment of our equity investment in Coastal GasLink LP, which resulted in a pre-tax impairment charge of $2,100 million ($1,943 million after tax) for the year ended December 31, 2023, in Impairment of equity investment in the Consolidated statement of income in the Canadian Natural Gas Pipelines segment. The impairment charge reflected the net impact of changes in the subordinated loan for the nine months ended September 30, 2023, along with TC Energy's proportionate share of unrealized gains and losses on interest rate derivatives in Coastal GasLink LP and other changes to the equity investment. The cumulative pre-tax impairment charge recognized to date at December 31, 2023 is $5,148 million ($4,586 million after tax). The impairment of the subordinated loan resulted in unrealized non-taxable capital losses that are not recognized. Refer to Note 8, Coastal GasLink, of our 2023 Consolidated financial statements for additional information.

The fair value of TC Energy's investment in Coastal GasLink LP at September 30, 2023 was estimated using a 40-year discounted cash flow model and incorporated assumptions related to the capital cost estimates, discount rates and long-term financing plans.

At December 31, 2023, there were no events or changes in circumstances from September 30, 2023 indicating a significant adverse impact on the estimated fair value of our investment in Coastal GasLink LP, therefore there was no other-than-temporary impairment that existed at December 31, 2023. Refer to our 2023 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.

Qualitative goodwill impairment indicators

As part of the annual goodwill impairment assessment at December 31, 2023, we evaluated qualitative factors impacting the fair value of the underlying reporting units for all reporting units other than for the Tuscarora and North Baja reporting units, which are described below. It was determined that it was more likely than not that the fair value of these reporting units exceeded their carrying amounts, including goodwill.

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 of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf, we performed a quantitative goodwill impairment test for the Columbia Pipeline Group, Inc. (Columbia) reporting unit at June 30, 2023. Refer to the U.S. Natural Gas Pipelines – Significant events section for additional information on this sale transaction.

In the determination of the fair value utilized in the quantitative goodwill impairment test 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.

North Baja and Tuscarora

We elected to proceed directly to a quantitative annual impairment test at December 31, 2023 for the $63 million of goodwill related to the North Baja reporting unit due to the passage of time from the previous quantitative test at December 31, 2018. We also elected to proceed directly to a quantitative annual impairment test for the $30 million of goodwill related to the Tuscarora reporting unit due to the passage of time from the previous quantitative test at December 31, 2018, and subsequent to the Tuscarora Section 4 rate case settlement in 2023. It was determined that the fair values of North Baja and Tuscarora exceeded their carrying values, including goodwill, at December 31, 2023.

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 $)	**2023**	**2022**
Other current assets	**1,285**	614
Other long-term assets	**155**	91
Accounts payable and other	**(1,143)**	(871)
Other long-term liabilities	**(106)**	(151)
	191	(317)

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, 2023 (millions of $)	**Total fair value**	**< 1 year**	**1 - 3 years**	**4 - 5 years**	**> 5 years**
Derivative instruments held for trading	181	142	75	24	(60)
Derivative instruments in hedging relationships	10	—	(2)	5	7
	191	142	73	29	(53)

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 $)	2023	2022	2021
Derivative Instruments Held for Trading[1]			
Unrealized gains (losses) in the year			
Commodities	**96**	14	9
Foreign exchange	**246**	(149)	(203)
Realized gains (losses) in the year			
Commodities	**811**	759	287
Foreign exchange	**155**	(2)	240
Derivative Instruments in Hedging Relationships[2]			
Realized gains (losses) in the year			
Commodities	**(2)**	(73)	(44)
Interest rate	**(43)**	(3)	(32)

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.

2 In 2023, there were no gains or losses included in Net income (loss) relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur (2022 – nil; 2021 – realized loss of $10 million).

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 29, Risk management and financial instruments, of our 2023 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.

TC Energy Subordinated Loan Agreement

TC Energy has a subordinated loan agreement with Coastal GasLink LP under which draws by Coastal GasLink LP will fund the remaining $0.9 billion (December 31, 2022 – $3.3 billion) equity requirement related to the estimated capital cost to complete the Coastal GasLink pipeline. At December 31, 2023, the total capacity committed by TC Energy under this subordinated loan agreement was $3.4 billion.

Any amounts outstanding on this loan will be repaid by Coastal GasLink LP to TC Energy, once final project costs are known, which will be determined after the pipeline is placed in service. Coastal GasLink LP partners, including TC Energy, will contribute equity to Coastal GasLink LP to ultimately fund Coastal GasLink LP's repayment of this subordinated loan to TC Energy. We expect that, in accordance with contractual terms, these additional equity contributions will be predominantly funded by TC Energy but will not result in a change to our 35 per cent ownership. The total amount drawn on this loan at December 31, 2023 was $2,520 million (December 31, 2022 – $250 million). Due to impairment charges recognized during the year, the carrying value of this loan was $500 million at December 31, 2023 (2022 – nil).

Subordinated Demand Revolving Credit Facility

We have a subordinated demand revolving credit facility with Coastal GasLink LP to provide additional short-term liquidity and funding flexibility to the project. The facility bears interest at a floating market-based rate and had a capacity of $100 million with an outstanding balance of nil at December 31, 2023 (December 31, 2022 – nil). This revolver was not impacted by the impairment charge recognized to date.

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. On March 15, 2022, as part of refinancing activities with the Sur de Texas joint venture, the peso-denominated inter-affiliate loan was replaced with a new U.S. dollar-denominated inter-affiliate loan from us for 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.

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 $)	**2023**	**2022**	**2021**	**Affected line item in the Consolidated statement of income**
Interest income[1]	—	19	87	Interest income and other
Interest expense[2]	—	(19)	(87)	Income from equity investments
Foreign exchange losses[1]	—	(28)	(41)	Foreign exchange (gains) losses, net
Foreign exchange gains[1]	—	28	41	Income 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 2023 Consolidated financial statements.

QUARTERLY RESULTS

Selected quarterly consolidated financial data

2023 (millions of $, except per share amounts)	Fourth	Third	Second	First
Revenues	**4,236**	**3,940**	**3,830**	**3,928**
Net income (loss) attributable to common shares	**1,463**	**(197)**	**250**	**1,313**
Comparable earnings	**1,403**	**1,035**	**981**	**1,233**
Share statistics:				
Net income (loss) per common share – basic	**$1.41**	**($0.19)**	**$0.24**	**$1.29**
Comparable earnings per common share	**$1.35**	**$1.00**	**$0.96**	**$1.21**
Dividends declared per common share	**$0.93**	**$0.93**	**$0.93**	**$0.93**

2022 (millions of $, except per share amounts)	Fourth	Third	Second	First
Revenues	4,041	3,799	3,637	3,500
Net income (loss) attributable to common shares	(1,447)	841	889	358
Comparable earnings	1,129	1,068	979	1,103
Share statistics:				
Net income (loss) per common share – basic	($1.42)	$0.84	$0.90	$0.36
Comparable earnings per common share	$1.11	$1.07	$1.00	$1.12
Dividends declared per common share	$0.90	$0.90	$0.90	$0.90

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.

In our Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Mexico Natural Gas Pipelines segments, 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 Liquids Pipelines, annual revenues and segmented earnings are based on contracted and uncontracted spot transportation, as well as liquids marketing activities. Quarter-over-quarter revenues and segmented earnings are affected by:

- regulatory decisions
- newly constructed assets being placed in service
- acquisitions and divestitures
- demand for uncontracted transportation services
- liquids marketing activities and commodity prices
- developments outside of the normal course of operations
- certain fair value adjustments.

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.

We exclude from comparable measures the unrealized gains and losses from changes in the fair value of derivatives related to financial and commodity price risk management activities. These derivatives generally provide effective economic hedges but do not meet the criteria for hedge accounting. We also exclude from comparable measures our proportionate share of the unrealized gains and losses from changes in the fair value of Bruce Power's funds invested for post-retirement benefits and derivatives related to its risk management activities. These changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them reflective of our underlying operations.

In fourth quarter 2023, comparable earnings 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
- an $18 million after-tax recovery 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
- an after-tax unrealized foreign exchange loss of $55 million on the peso-denominated intercompany loan between TCPL and TGNH
- a $25 million after-tax loss on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico
- an after-tax charge of $23 million due to Liquids Pipelines business separation costs related to the spinoff Transaction
- a $9 million after-tax expense related to Focus Project costs
- carrying charges of $4 million after tax 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 from 2018 to 2022
- preservation and other costs for Keystone XL pipeline project assets of $4 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge.

In third quarter 2023, comparable earnings also excluded:

- an after-tax impairment charge of $1,179 million related to our equity investment in Coastal GasLink LP
- a $14 million after-tax expense related to Focus Project costs
- an after-tax charge of $11 million due to Liquids Pipelines business separation costs related to the spinoff Transaction
- preservation and other costs for Keystone XL pipeline project assets of $2 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- an after-tax net unrealized foreign exchange gain of $20 million on the peso-denominated intercompany loan between TCPL and TGNH.

In second quarter 2023, comparable earnings also excluded:
- an after-tax impairment charge of $809 million related to our equity investment in Coastal GasLink LP
- a $36 million after-tax accrued insurance expense related to the Milepost 14 incident
- a $25 million after-tax expense related to Focus Project costs
- an after-tax net unrealized foreign exchange loss of $9 million on the peso-denominated intercompany loan between TCPL and TGNH
- preservation and other costs for Keystone XL pipeline project assets of $4 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- an $8 million after-tax recovery on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico.

In first quarter 2023, comparable earnings also excluded:
- a $72 million after-tax recovery on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico
- $48 million after-tax 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 and accrued pre-tax carrying charges of $5 million
- an after-tax impairment charge of $29 million related to our equity investment in Coastal GasLink LP
- preservation and other costs for Keystone XL pipeline project assets of $4 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge.

In fourth quarter 2022, comparable earnings also excluded:
- an after-tax impairment charge of $2.6 billion related to our equity investment in Coastal GasLink LP
- a $64 million after-tax expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico
- $20 million after-tax charge due to the CER decision on Keystone issued in December 2022 in respect of a tolling-related complaint pertaining to amounts reflected in 2021 and 2020
- preservation and other costs for Keystone XL pipeline project assets of $8 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $5 million after-tax net expense related to the 2021 Keystone XL asset impairment charge and other due to a U.S. minimum tax, partially offset by the gain on the sale of Keystone XL project assets and reduction to the estimate for contractual and legal obligations related to termination activities
- a $1 million income tax expense for the settlement related to prior years' income tax assessments in Mexico.

In third quarter 2022, comparable earnings also excluded:
- preservation and other costs for Keystone XL pipeline project assets of $3 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge.

In second quarter 2022, comparable earnings also excluded:
- preservation and other costs for Keystone XL pipeline project assets of $3 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $2 million income tax expense for the settlement related to prior years' income tax assessments in Mexico.

In first quarter 2022, comparable earnings also excluded:
- an after-tax goodwill impairment charge of $531 million related to Great Lakes
- a $193 million income tax expense for the settlement-in-principle of matters related to prior years' income tax assessments in Mexico
- preservation and other costs for Keystone XL pipeline project assets of $5 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge.

FOURTH QUARTER 2023 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	2023	2022
Canadian Natural Gas Pipelines	**692**	(2,592)
U.S. Natural Gas Pipelines	**955**	882
Mexico Natural Gas Pipelines	**150**	96
Liquids Pipelines	**309**	322
Power and Energy Solutions	**263**	298
Corporate	**(42)**	(4)
Total segmented earnings (losses)	**2,327**	(998)
Interest expense	**(845)**	(722)
Allowance for funds used during construction	**132**	115
Foreign exchange gains (losses), net	**89**	132
Interest income and other	**121**	53
Income (loss) before income taxes	**1,824**	(1,420)
Income tax (expense) recovery	**(209)**	4
Net income (loss)	**1,615**	(1,416)
Net (income) loss attributable to non-controlling interests	**(128)**	(9)
Net income (loss) attributable to controlling interests	**1,487**	(1,425)
Preferred share dividends	**(24)**	(22)
Net income (loss) attributable to common shares	**1,463**	(1,447)
Net income (loss) per common share – basic	**$1.41**	($1.42)

Net income (loss) attributable to common shares increased by $2.9 billion or $2.83 per common share for the three months ended December 31, 2023 compared to the same period in 2022. The significant increase for the three months ended December 31, 2023 is primarily due to the net effect of the specific items mentioned below. Net income per common share in both periods also reflect the impact of common shares issued in 2023 and 2022.

Fourth quarter 2023 results included:

- 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
- an $18 million after-tax recovery 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
- an after-tax unrealized foreign exchange loss of $55 million on the peso-denominated intercompany loan between TCPL and TGNH
- a $25 million after-tax loss on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico
- an after-tax charge of $23 million due to Liquids Pipelines business separation costs related to the spinoff Transaction
- a $9 million after-tax expense related to Focus Project costs
- carrying charges of $4 million after tax 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 from 2018 to 2022
- preservation and other costs for Keystone XL pipeline project assets of $4 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge.

Fourth quarter 2022 results included:

- an after-tax impairment charge of $2.6 billion related to our equity investment in Coastal GasLink LP
- a $64 million after-tax expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico
- $20 million after-tax charge due to the CER decision on Keystone issued in December 2022 in respect of a tolling-related complaint pertaining to amounts reflected in 2021 and 2020
- preservation and other costs for Keystone XL pipeline project assets of $8 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $5 million after-tax net expense related to the 2021 Keystone XL asset impairment charge and other due to U.S. minimum tax, partially offset by the gain on the sale of Keystone XL project assets and adjustments to the estimate for contractual and legal obligations related to termination activities
- a $1 million income tax expense for the settlement related to prior years' income tax assessments in Mexico.

Net income in each period included unrealized gains and losses on our proportionate share of Bruce Power's fair value adjustment on funds invested for post-retirement benefits and derivatives related to its risk management activities, as well as unrealized gains and losses from changes in our risk management activities, all of which we exclude along with the above noted items, to arrive at comparable earnings. A reconciliation of Net income (loss) attributable to common shares to comparable earnings is shown in the following table.

Reconciliation of net income (loss) attributable to common shares to comparable earnings

three months ended December 31 (millions of $, except per share amounts)	2023	2022
Net income (loss) attributable to common shares	**1,463**	(1,447)
Specific items (net of tax):		
Coastal GasLink impairment charge	**(74)**	2,643
Keystone XL asset impairment charge and other	**(18)**	5
Foreign exchange (gains) losses, net – intercompany loan	**55**	—
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**25**	64
Liquids Pipelines business separation costs	**23**	—
Focus Project costs	**9**	—
Keystone regulatory decisions	**4**	20
Keystone XL preservation and other	**4**	8
Milepost 14 insurance expense	**—**	—
Settlement of Mexico prior years' income tax assessments	**—**	1
Bruce Power unrealized fair value adjustments	**(5)**	(9)
Risk management activities[1]	**(83)**	(156)
Comparable earnings	**1,403**	1,129
Net income (loss) per common share	**$1.41**	($1.42)
Specific items (net of tax):		
Coastal GasLink impairment charge	**(0.07)**	2.60
Keystone XL asset impairment charge and other	**(0.02)**	—
Foreign exchange (gains) losses, net – intercompany loan	**0.05**	—
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**0.03**	0.06
Liquids Pipelines business separation costs	**0.02**	—
Focus Project costs	**0.01**	—
Keystone regulatory decisions	**—**	0.02
Keystone XL preservation and other	**—**	0.01
Milepost 14 insurance expense	**—**	—
Settlement of Mexico prior years' income tax assessments	**—**	—
Bruce Power unrealized fair value adjustments	**—**	(0.01)
Risk management activities	**(0.08)**	(0.15)
Comparable earnings per common share	**$1.35**	$1.11

1

three months ended December 31 (millions of $)	2023	2022
U.S. Natural Gas Pipelines	**(29)**	(28)
Liquids Pipelines	**20**	(38)
Canadian Power	**(6)**	30
U.S. Power	**4**	5
Natural Gas Storage	**18**	67
Foreign exchange	**104**	172
Income tax attributable to risk management activities	**(28)**	(52)
Total unrealized gains (losses) from risk management activities	**83**	156

Comparable EBITDA to comparable earnings

Comparable EBITDA 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)	2023	2022
Comparable EBITDA		
Canadian Natural Gas Pipelines	**1,034**	768
U.S. Natural Gas Pipelines	**1,225**	1,141
Mexico Natural Gas Pipelines	**208**	211
Liquids Pipelines	**379**	364
Power and Energy Solutions	**266**	203
Corporate	**(5)**	(4)
Comparable EBITDA	**3,107**	2,683
Depreciation and amortization	**(717)**	(670)
Interest expense included in comparable earnings	**(840)**	(722)
Allowance for funds used during construction	**132**	115
Foreign exchange gains (losses), net included in comparable earnings	**40**	(40)
Interest income and other included in comparable earnings	**121**	53
Income tax (expense) recovery included in comparable earnings	**(288)**	(259)
Net (income) loss attributable to non-controlling interests	**(128)**	(9)
Preferred share dividends	**(24)**	(22)
Comparable earnings	**1,403**	1,129
Comparable earnings per common share	**$1.35**	$1.11

Comparable EBITDA – 2023 versus 2022

Comparable EBITDA increased by $424 million for the three months ended December 31, 2023 compared to the same period in 2022 primarily due to the net effect of the following:

- increased EBITDA in Canadian Natural Gas Pipelines mainly as a result of higher contributions from Coastal GasLink related to the recognition of a $200 million incentive payment upon meeting certain milestones and higher flow-through costs and increased rate-base earnings on the NGTL System
- increased Power and Energy Solutions EBITDA attributable to higher realized Alberta natural gas storage spreads, higher contributions from Bruce Power and increased Canadian Power financial results due to higher contributions from marketing activities
- increased U.S. dollar-denominated EBITDA from U.S. Natural Gas Pipelines as a result of incremental earnings from growth and modernization projects placed in service and higher net earnings from additional contract sales, along with certain fourth quarter 2022 adjustments, partially offset by higher operational costs reflective of increased utilization and lower commodity prices related to our mineral rights business
- increased EBITDA from Liquids Pipelines primarily due to higher volumes on the Keystone Pipeline System, partially offset by the negative impact of the CER decision issued in December 2022 in respect of a tolling-related complaint pertaining to amounts invoiced in 2022
- decreased U.S. dollar-denominated EBITDA from Mexico Natural Gas Pipelines attributable to lower earnings from Guadalajara due to lower fixed revenue and higher operating costs due to a weather event, partially offset by earnings from the lateral section of the Villa de Reyes pipeline which was placed in commercial service in third quarter 2023.

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 – 2023 versus 2022

Comparable earnings increased by $274 million or $0.24 per common share for the three months ended December 31, 2023 compared to the same period in 2022 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher interest expense primarily due to long-term debt issuances, net of maturities, the foreign exchange impact on translation of increased U.S. dollar-denominated interest expense, partially offset by higher capitalized interest and reduced levels of short-term borrowings
- higher depreciation and amortization on the NGTL System from expansion facilities that were placed in service
- higher AFUDC primarily due to capital expenditures on the Southeast Gateway pipeline project, partially offset by the impact of NGTL System expansion projects that were placed in service and the suspension of AFUDC on the Tula pipeline project, effective November 1, 2023, due to the delay of an FID
- increased income tax expense due to the impact of higher comparable earnings subject to income tax and Mexico foreign exchange exposure, partially offset by lower flow-through income taxes, higher foreign income tax rate differentials and lower Mexico inflation adjustments
- impact of derivatives used to manage our net exposure to foreign exchange rate fluctuation on U.S. dollar-denominated income and our foreign exchange exposure to net liabilities in Mexico
- higher interest income and other due to higher interest earned on short-term investments and the change in fair value of other restricted investments
- 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 for the three months ended December 31, 2023 reflect the dilutive effect of common shares issued in 2023 and 2022.

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. The balance of the 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, 2023, 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 along with the majority of our Liquids Pipelines business. Comparable EBITDA is a non-GAAP measure.

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

three months ended December 31 (millions of US$)	**2023**	**2022**
Comparable EBITDA		
U.S. Natural Gas Pipelines	**900**	842
Mexico Natural Gas Pipelines	**153**	156
Liquids Pipelines	**204**	204
	1,257	1,202
Depreciation and amortization	**(241)**	(237)
Interest expense on long-term debt and junior subordinated notes	**(473)**	(323)
Allowance for funds used during construction	**81**	55
Non-controlling interests and other	**(92)**	(44)
	532	653
Average exchange rate - U.S. to Canadian dollars	**1.36**	1.36

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 and Foreign exchange (gains) losses, net 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. On January 17, 2023, a wholly-owned Mexican subsidiary entered into a US$1.8 billion senior unsecured term loan and a US$500 million senior unsecured revolving credit facility with a third party, which resulted in an additional peso-denominated income tax expense compared to 2022.

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, 2023	**16.91**
December 31, 2022	19.50
December 31, 2021	20.48

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 $)	**2023**	**2022**
Comparable EBITDA - Mexico Natural Gas Pipelines[1]	**(16)**	(15)
Foreign exchange gains (losses), net included in comparable earnings	**64**	34
Income tax (expense) recovery included in comparable earnings	**(38)**	(9)
	10	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.

Highlights by business segment

Canadian Natural Gas Pipelines

For the three months ended December 31, 2023, Canadian Natural Gas Pipelines segmented earnings were $0.7 billion compared to segmented losses of $2.6 billion for the same period in 2022. Segmented losses included a pre-tax impairment charge of $3.0 billion, for the three months ended December 31, 2022, related to our equity investment in Coastal GasLink LP, which has been excluded from our calculation of comparable EBITDA and comparable EBIT. Refer to Note 8, Coastal GasLink, of our 2023 Consolidated financial statements for additional information.

Net income for the NGTL System increased by $13 million for the three months ended December 31, 2023 compared to the same period in 2022 mainly due to a higher average investment base resulting from continued system expansions. The NGTL System is operating under the 2020-2024 Revenue Requirement Settlement, which includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provides 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 for the three months ended December 31, 2023 was consistent with the same period in 2022. The Canadian Mainline is operating under the 2021-2026 Mainline Settlement, which includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity and an incentive to decrease costs and increase revenues on the pipeline under a beneficial sharing mechanism with our customers.

Comparable EBITDA for Canadian Natural Gas Pipelines increased by $266 million for the three months ended December 31, 2023 compared to the same period in 2022 due to the net effect of:

- earnings from Coastal GasLink related to the recognition of a $200 million incentive payment upon meeting certain milestones. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information
- higher flow-through financial charges, depreciation and income taxes, as well as higher rate-base earnings on the NGTL System.

Depreciation and amortization increased by $30 million for the three months ended December 31, 2023 compared to the same period in 2022 reflecting incremental 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.

U.S. Natural Gas Pipelines

U.S. Natural Gas Pipelines segmented earnings increased by $73 million for the three months ended December 31, 2023 compared to the same period in 2022 and included unrealized gains and losses from changes in the fair value of derivatives related to our U.S. natural gas marketing business, which has been excluded from our calculation of comparable EBITDA and comparable EBIT.

Higher U.S. dollar-denominated segmented earnings for the three months ended December 31, 2023 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2022.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$58 million for the three months ended December 31, 2023 compared to the same period in 2022 and was primarily due to the net effect of:

- incremental earnings from growth and modernization projects placed in service
- a net increase in earnings from additional contract sales on Columbia Gas, ANR and Great Lakes along with certain fourth quarter 2022 adjustments related to ANR regulatory deferrals
- increased equity earnings from Iroquois
- reduced earnings from our mineral rights business due to lower commodity prices
- 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.

Depreciation and amortization increased by US$5 million for the three months ended December 31, 2023 compared to the same period in 2022 due to new projects placed in service.

Mexico Natural Gas Pipelines

Mexico Natural Gas Pipelines segmented earnings increased by $54 million for the three months ended December 31, 2023 compared to the same period in 2022 and included a loss of $36 million (2022 – loss of $92 million) on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico, which has been excluded from our calculation of comparable EBITDA and comparable EBIT. Refer to Note 29, Risk management and financial instruments, of our 2023 Consolidated financial statements for additional information.

Comparable EBITDA for Mexico Natural Gas Pipelines decreased by US$3 million for the three months ended December 31, 2023 compared to the same period in 2022 due to the net effect of:

- 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
- higher earnings in TGNH primarily related to the lateral section of the Villa de Reyes pipeline which was placed in commercial service in third quarter 2023.

Depreciation and amortization was consistent for the three months ended December 31, 2023 compared to the same period in 2022.

Liquids Pipelines

Liquids Pipelines segmented earnings decreased by $13 million for the three months ended December 31, 2023 compared to the same period in 2022 and included the following specific items, which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- pre-tax preservation and other costs for Keystone XL pipeline project assets of $5 million for the three months ended December 31, 2023 (2022 – $10 million), which could not be accrued as part of the Keystone XL asset impairment charge
- a pre-tax charge of $3 million incurred in fourth quarter 2023 due to Liquids Pipelines business separation costs related to the spinoff Transaction
- a $4 million pre-tax adjustment for the three months ended December 31, 2023 (2022 – $118 million) to the 2021 Keystone XL asset impairment charge and other resulting from the net effect of the gain on sale of Keystone XL project assets and adjustments to the estimate for contractual and legal obligations related to termination activities
- a $27 million pre-tax charge due to the CER decision issued in December 2022 in respect of a tolling-related complaint pertaining to amounts reflected in 2021 and 2022
- unrealized gains and losses from changes in the fair value of derivatives related to our liquids marketing business.

Comparable EBITDA for Liquids Pipelines increased by $15 million for the three months ended December 31, 2023 compared to the same period in 2022 primarily due to the net effect of:

- higher contracted volumes on the U.S. Gulf Coast section of the Keystone Pipeline System
- higher uncontracted volumes on the Keystone Pipeline System
- the negative impact of the CER decision issued in December 2022 in respect of a tolling-related complaint pertaining to amounts invoiced in 2022.

Depreciation and amortization was consistent for the three months ended December 31, 2023 compared with the same period in 2022.

Power and Energy Solutions

Power and Energy Solutions segmented earnings decreased by $35 million for the three months ended December 31, 2023 compared to the same period in 2022 and included the following specific items, which have been excluded from our calculations of comparable EBITDA and comparable EBIT:

- 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 $63 million for the three months ended December 31, 2023 compared to the same period in 2022 primarily due to the net effect of:

- increased Natural Gas Storage and other results from higher realized Alberta natural gas storage spreads
- higher contributions from Bruce Power primarily due to realized gains on funds invested for post-retirement benefits, an increased contract price and lower operating expenses, partially offset by lower generation
- increased Canadian Power financial results due to higher net contributions from marketing activities, partially offset by lower realized power prices.

Depreciation and amortization increased by $7 million for the three months ended December 31, 2023 compared to the same period in 2022 primarily due to the acquisition of the Texas Wind Farms in the first half of 2023.

Corporate

Corporate segmented losses increased by $38 million for the three months ended December 31, 2023 compared to the same period in 2022 and included the following specific items, which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax charge of $22 million incurred in fourth quarter 2023 due to Liquids Pipelines business separation costs related to the spinoff Transaction
- a pre-tax charge of $15 million for the three months ended December 31, 2023 related to Focus Project costs.

Comparable EBITDA and EBIT for Corporate remained consistent for the three months ended December 31, 2023 compared to the same period in 2022.

Glossary

Units of measure

Bbl/d	Barrel(s) per day
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
PJ/d	Petajoule per day
TJ/d	Terajoule per day

General terms and terms related to our operations

bitumen	A thick, heavy oil that must be diluted to flow (also see: diluent). One of the components of the oil sands, along with sand, water and clay
CEO	Chief Executive Officer
CFO	Chief Financial Officer
cogeneration facilities	Facilities that produce both electricity and useful heat at the same time
diluent	A thinning agent made up of organic compounds. Used to dilute bitumen so it can be transported through pipelines
DRP	Dividend Reinvestment and Share Purchase Plan
Empress	A major delivery/receipt point for natural gas near the Alberta/Saskatchewan border
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)
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
TCFD	Task Force on Climate-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 2023 to that in 2022, and highlights significant changes between 2022 and 2021. 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, 2023, 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



Joel E. Hunter
Executive Vice-President and
Chief Financial Officer

February 15, 2024

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, 2023 and 2022, 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, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2023, 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, 2023, 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 15, 2024 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the Audit Committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements; and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Valuation of the equity investment in Coastal GasLink LP

As discussed in Notes 2 and 8 to the consolidated financial statements, 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.

With the expectation that additional equity contributions under the subordinated loan agreement between the Company and Coastal GasLink LP will be predominantly funded by TC Energy as a limited partner of Coastal GasLink LP, the Company completed valuation assessments during the first three quarters of 2023 and concluded that the fair value of its investment in Coastal GasLink LP was below its carrying value and that these were other-than-temporary impairments. As a result, a pre-tax impairment charge of $2,100 million was recognized during the nine months ended September 30, 2023. Fair value was estimated using a 40-year discounted cash flow model and incorporated assumptions related to capital cost estimates, discount rates, and long-term financing plans (collectively, the "key assumptions").

We identified the valuation of the equity investment in Coastal GasLink LP at September 30, 2023 as a critical audit matter. A high degree of auditor judgment was required to evaluate the key assumptions. Minor changes to the key assumptions could have had a significant effect on the Company's determination of the fair value of the investment. In addition, the audit effort associated with this estimate 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 critical audit matter. This included controls related to the Company's determination of the fair value of the investment and its evaluation of the key assumptions. We recalculated the capital cost estimates by comparing the project budget to the actual costs incurred to September 30, 2023. We also compared the amounts in the project budget to project status and milestone reporting provided to the partners of Coastal GasLink LP. We compared assumptions used in the long-term financing plans to publicly available data for comparable financing transactions and financing reports provided to the partners of Coastal GasLink LP. In addition, we involved a valuation professional with specialized skills and knowledge, who assisted in:

- evaluating the methodology used by management in the valuation by comparing it to methodologies used to value other development stage entities; and
- evaluating the discount rates used by management in the valuation by comparing them to discount rate ranges that were independently developed using publicly available market data for comparable entities.

Valuation of goodwill for the Columbia reporting unit

As discussed in Notes 2 and 15 to the consolidated financial statements, the goodwill balance as of December 31, 2023 for the Columbia reporting unit was $9,708 million. 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. In respect of the Columbia reporting unit, the Company performed a quantitative goodwill impairment test on June 30, 2023 (the "June 30, 2023 impairment test") in conjunction with the process leading up to the sale of a 40 per cent equity interest in Columbia Gas Transmission, LLC (Columbia Gas) and Columbia Gulf Transmission, LLC (Columbia Gulf) (the "Transaction"). The quantitative goodwill impairment assessment involves determining the fair value of a reporting unit and comparing that value to the carrying value of the reporting unit, including goodwill. Fair value is estimated using a discounted cash flow model which requires the use of assumptions related to revenue and capital expenditure projections, the valuation multiple and the discount rate (collectively, the "key assumptions"). 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, as of June 30, 2023. Although goodwill was not impaired, the estimated fair value in excess of the carrying value was less than 10 per cent.

We identified the valuation of goodwill for the Columbia reporting unit as a critical audit matter. A high degree of auditor judgment was required to evaluate the key assumptions. Minor changes to the key assumptions could have had a significant effect on the Company's determination of the fair value of the Columbia reporting unit. In addition, the audit effort associated with this estimate 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 critical audit matter. This included controls related to the Company's determination of the fair value of the Columbia reporting unit and its evaluation of the key assumptions. We compared the Company's historical revenue and capital expenditure projections used in the prior quantitative goodwill impairment test to 2023 actual results to assess the Company's ability to accurately forecast. We evaluated the Company's revenue and capital expenditure projections in the June 30, 2023 impairment test by comparing them to 2023 actual results and to assumptions used in industry publications related to North American and global energy consumption and production forecasts. We also inspected the executed agreements associated with the Transaction to assess whether the closing terms and

economic value of the Transaction were consistent with the key assumptions and the fair value determined from the discounted cash flow model. In addition, we involved a valuation professional with specialized skills and knowledge, who assisted in:

- evaluating the Company's determination of a valuation multiple by comparing it to independently observed recent market transactions of comparable assets and publicly available market data for comparable entities
- evaluating the discount rate used by management in the valuation, by comparing it against a discount rate range that was independently developed using publicly available market data for comparable entities
- evaluating the Company's estimate of the fair value of the Columbia reporting unit by comparing the result of the Company's estimate to publicly available market data and valuation metrics for comparable entities.

Qualitative goodwill impairment indicators for the Columbia and ANR reporting units

As discussed in Notes 2 and 15 to the consolidated financial statements, the goodwill balance as of December 31, 2023 for the Columbia Pipeline Group, Inc. (Columbia) and the American Natural Resources (ANR) reporting units was $9,708 million and $2,570 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, 2023.

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.



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

Calgary, Canada
February 15, 2024

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, 2023, 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, 2023, 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, 2023 and 2022, 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, 2023, and the related notes (collectively, the consolidated financial statements), and our report dated February 15, 2024 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting included in the Company's 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.

KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 15, 2024

Consolidated statement of income

year ended December 31 (millions of Canadian $, except per share amounts)	2023	2022	2021
Revenues (Note 6)			
Canadian Natural Gas Pipelines	**5,173**	4,764	4,519
U.S. Natural Gas Pipelines	**6,229**	5,933	5,233
Mexico Natural Gas Pipelines	**846**	688	605
Liquids Pipelines	**2,667**	2,668	2,306
Power and Energy Solutions	**1,019**	924	724
	15,934	14,977	13,387
Income (Loss) from Equity Investments (Note 12)	**1,377**	1,054	898
Impairment of Equity Investment (Notes 8 and 12)	**(2,100)**	(3,048)	—
Operating and Other Expenses			
Plant operating costs and other	**4,887**	4,932	4,098
Commodity purchases resold	**517**	534	87
Property taxes	**897**	848	774
Depreciation and amortization	**2,778**	2,584	2,522
Goodwill and asset impairment charges and other (Notes 7 and 15)	**(4)**	453	2,775
	9,075	9,351	10,256
Net Gain (Loss) on Sale of Assets	**—**	—	30
Financial Charges			
Interest expense (Note 21)	**3,263**	2,588	2,360
Allowance for funds used during construction	**(575)**	(369)	(267)
Foreign exchange (gains) losses, net (Note 23)	**(320)**	185	(10)
Interest income and other	**(242)**	(146)	(190)
	2,126	2,258	1,893
Income (Loss) before Income Taxes	**4,010**	1,374	2,166
Income Tax Expense (Recovery) (Note 20)			
Current	**931**	415	305
Deferred	**11**	174	(185)
	942	589	120
Net Income (Loss)	**3,068**	785	2,046
Net income (loss) attributable to non-controlling interests (Note 24)	**146**	37	91
Net Income (Loss) Attributable to Controlling Interests	**2,922**	748	1,955
Preferred share dividends	**93**	107	140
Net Income (Loss) Attributable to Common Shares	**2,829**	641	1,815
Net Income (Loss) per Common Share (Note 25)			
Basic	**$2.75**	$0.64	$1.87
Diluted	**$2.75**	$0.64	$1.86
Dividends Declared per Common Share	**$3.72**	$3.60	$3.48
Weighted Average Number of Common Shares (millions) (Note 25)			
Basic	**1,030**	995	973
Diluted	**1,030**	996	974

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 $)	2023	2022	2021
Net Income (Loss)	**3,068**	785	2,046
Other Comprehensive Income (Loss), Net of Income Taxes			
Foreign currency translation gains and losses on net investment in foreign operations	**(1,141)**	1,494	(108)
Change in fair value of net investment hedges	**17**	(36)	(2)
Change in fair value of cash flow hedges	**—**	(39)	(10)
Reclassification to net income of (gains) losses on cash flow hedges	**74**	42	55
Unrealized actuarial gains (losses) on pension and other post-retirement benefit plans	**(11)**	63	158
Reclassification to net income of actuarial (gains) losses on pension and other post-retirement benefit plans	**—**	6	14
Other comprehensive income (loss) on equity investments	**(211)**	867	535
Other comprehensive income (loss) (Note 27)	**(1,272)**	2,397	642
Comprehensive Income (Loss)	**1,796**	3,182	2,688
Comprehensive income (loss) attributable to non-controlling interests	**(220)**	45	81
Comprehensive Income (Loss) Attributable to Controlling Interests	**2,016**	3,137	2,607
Preferred share dividends	**93**	107	140
Comprehensive Income (Loss) Attributable to Common Shares	**1,923**	3,030	2,467

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 $)	2023	2022	2021
Cash Generated from Operations			
Net income (loss)	**3,068**	785	2,046
Depreciation and amortization	**2,778**	2,584	2,522
Goodwill and asset impairment charges and other (Notes 7 and 15)	**(4)**	453	2,775
Deferred income taxes (Note 20)	**11**	174	(185)
(Income) loss from equity investments (Note 12)	**(1,377)**	(1,054)	(898)
Impairment of equity investment (Notes 8 and 12)	**2,100**	3,048	—
Distributions received from operating activities of equity investments (Note 12)	**1,254**	1,025	975
Employee post-retirement benefits funding, net of expense (Note 28)	**(17)**	(29)	(5)
Net (gain) loss on sale of assets	**—**	—	(30)
Equity allowance for funds used during construction	**(367)**	(248)	(191)
Unrealized (gains) losses on financial instruments (Note 29)	**(342)**	135	194
Expected credit loss provision (Note 29)	**(83)**	163	—
Foreign exchange losses on loan receivable from affiliate (Note 13)	**—**	28	41
Other	**40**	(50)	(67)
(Increase) decrease in operating working capital (Note 30)	**207**	(639)	(287)
Net cash provided by operations	**7,268**	6,375	6,890
Investing Activities			
Capital expenditures (Note 5)	**(8,007)**	(6,678)	(5,924)
Capital projects in development (Note 5)	**(142)**	(49)	—
Contributions to equity investments (Notes 5, 8 and 12)	**(4,149)**	(3,433)	(1,210)
Acquisitions, net of cash acquired (Note 31)	**(307)**	—	—
Loans to affiliate (issued) repaid, net (Notes 8 and 13)	**250**	(11)	(239)
Keystone XL contractual recoveries (Note 7)	**10**	571	—
Proceeds from sales of assets, net of transaction costs	**33**	—	35
Other distributions from equity investments (Note 12)	**23**	2,632	73
Deferred amounts and other	**2**	(41)	(447)
Net cash (used in) provided by investing activities	**(12,287)**	(7,009)	(7,712)
Financing Activities			
Notes payable issued (repaid), net	**(6,299)**	766	1,003
Long-term debt issued, net of issue costs	**15,884**	2,508	10,730
Long-term debt repaid	**(3,772)**	(1,338)	(7,758)
Disposition of equity interest, net of transaction costs (Notes 24 and 31)	**5,328**	—	—
Junior subordinated notes issued, net of issue costs	**—**	1,008	495
Redeemable non-controlling interest repurchased (Note 7)	**—**	—	(633)
Dividends on common shares	**(2,787)**	(3,192)	(3,317)
Dividends on preferred shares	**(92)**	(106)	(141)
Distributions to non-controlling interests	**(124)**	(44)	(74)
Distributions on Class C Interests (Note 7)	**(49)**	(43)	(16)
Common shares issued, net of issue costs	**4**	1,905	148
Preferred shares redeemed (Note 26)	**—**	(1,000)	(500)
Gains (losses) on settlement of financial instruments	**—**	23	(10)
Acquisition of TC PipeLines, LP transaction costs (Note 24)	**—**	—	(15)
Net cash (used in) provided by financing activities	**8,093**	487	(88)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(16)**	94	53
Increase (Decrease) in Cash and Cash Equivalents	**3,058**	(53)	(857)
Cash and Cash Equivalents			
Beginning of year	**620**	673	1,530
Cash and Cash Equivalents			
End of year	**3,678**	620	673

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated balance sheet

at December 31 (millions of Canadian $)		2023	2022
ASSETS			
Current Assets			
Cash and cash equivalents		**3,678**	620
Accounts receivable		**4,209**	3,624
Inventories		**982**	936
Other current assets (Note 9)		**2,503**	2,152
		11,372	7,332
Plant, Property and Equipment (Note 10)		**80,569**	75,940
Net Investment in Leases (Note 11)		**2,263**	1,895
Equity Investments (Note 12)		**10,314**	9,535
Restricted Investments		**2,636**	2,108
Regulatory Assets (Note 14)		**2,330**	1,910
Goodwill (Note 15)		**12,532**	12,843
Other Long-Term Assets (Note 16)		**3,018**	2,785
		125,034	114,348
LIABILITIES			
Current Liabilities			
Notes payable (Note 17)		**—**	6,262
Accounts payable and other (Note 18)		**6,987**	7,149
Dividends payable		**979**	930
Accrued interest		**913**	668
Current portion of long-term debt (Note 21)		**2,938**	1,898
		11,817	16,907
Regulatory Liabilities (Note 14)		**4,806**	4,520
Other Long-Term Liabilities (Note 19)		**1,015**	1,017
Deferred Income Tax Liabilities (Note 20)		**8,125**	7,648
Long-Term Debt (Note 21)		**49,976**	39,645
Junior Subordinated Notes (Note 22)		**10,287**	10,495
		86,026	80,232
EQUITY			
Common shares, no par value (Note 25)		**30,002**	28,995
Issued and outstanding:	December 31, 2023 – 1,037 million shares December 31, 2022 – 1,018 million shares		
Preferred shares (Note 26)		**2,499**	2,499
Additional paid-in capital		**—**	722
Retained earnings (Accumulated deficit)		**(2,997)**	819
Accumulated other comprehensive income (loss) (Note 27)		**49**	955
Controlling Interests		**29,553**	33,990
Non-controlling interests (Note 24)		**9,455**	126
		39,008	34,116
		125,034	114,348

Commitments, Contingencies and Guarantees (Note 32)

Variable Interest Entities (Note 33)

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 $)	2023	2022	2021
Common Shares (Note 25)			
Balance at beginning of year	**28,995**	26,716	24,488
Shares issued:			
Dividend reinvestment and share purchase plan	**1,003**	342	—
Exercise of stock options	**4**	183	165
Under public offering, net of issue costs	**—**	1,754	—
Acquisition of TC PipeLines, LP, net of transaction costs (Note 24)	**—**	—	2,063
Balance at end of year	**30,002**	28,995	26,716
Preferred Shares (Note 26)			
Balance at beginning of year	**2,499**	3,487	3,980
Redemption of shares	**—**	(988)	(493)
Balance at end of year	**2,499**	2,499	3,487
Additional Paid-In Capital			
Balance at beginning of year	**722**	729	2
Issuance of stock options, net of exercises	**9**	(7)	(6)
Disposition of equity interest, net of transaction costs (Note 24)	**(3,537)**	—	—
Reclassification of additional paid-in capital deficit to retained earnings (accumulated deficit)	**2,806**	—	—
Keystone XL project-level credit facility retirement and issuance of Class C Interests (Note 7)	**—**	—	737
Acquisition of TC PipeLines, LP (Note 24)	**—**	—	(398)
Repurchase of redeemable non-controlling interest (Note 7)	**—**	—	394
Balance at end of year	**—**	722	729
Retained Earnings (Accumulated Deficit)			
Balance at beginning of year	**819**	3,773	5,367
Net income (loss) attributable to controlling interests	**2,922**	748	1,955
Common share dividends	**(3,839)**	(3,595)	(3,409)
Preferred share dividends	**(93)**	(95)	(133)
Reclassification of additional paid-in capital deficit to retained earnings (accumulated deficit)	**(2,806)**	—	—
Redemption of preferred shares	**—**	(12)	(7)
Balance at end of year	**(2,997)**	819	3,773
Accumulated Other Comprehensive Income (Loss) (Note 27)			
Balance at beginning of year	**955**	(1,434)	(2,439)
Other comprehensive income (loss) attributable to controlling interests	**(379)**	2,389	652
Impact of non-controlling interest (Note 24)	**(527)**	—	—
Acquisition of TC PipeLines, LP (Note 24)	**—**	—	353
Balance at end of year	**49**	955	(1,434)
Equity Attributable to Controlling Interests	**29,553**	33,990	33,271
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**126**	125	1,682
Disposition of equity interest (Note 24)	**9,451**	—	—
Non-controlling interests on acquisition of Texas Wind Farms (Note 24)	**222**	—	—
Net income (loss) attributable to non-controlling interests	**146**	37	90
Other comprehensive income (loss) attributable to non-controlling interests	**(366)**	8	(10)
Distributions declared to non-controlling interests	**(124)**	(44)	(74)
Acquisition of TC PipeLines, LP (Note 24)	**—**	—	(1,563)
Balance at end of year	**9,455**	126	125
Total Equity	**39,008**	34,116	33,396

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 infive business segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines and Power and Energy Solutions. These segments offer different products and services, including certain natural gas, crude oil 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 in40,596 km (25,226 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 in50,088 km (31,123 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 in2,895 km (1,798 miles) of regulated natural gas pipelines currently in operation.

Liquids Pipelines

The Liquids Pipelines segment primarily consists of the Company's investments in4,865 km (3,024 miles) of crude oil pipeline systems currently in operation which connect Alberta and U.S. crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas.

Power and Energy Solutions

The Power and Energy Solutions segment primarily consists of the Company's investments in approximately4,600 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.

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.

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 the estimate or judgment is made or are subjective. These estimates and judgments include, but are not limited to:

- fair value of TC Energy's equity investment in Coastal GasLink LP (Note 8)
- assessment of goodwill impairment indicators and fair value of reporting units that contain goodwill (Note 15)
- estimates and judgments used in measuring the fair value of Columbia Gas Transmission, LLC (Columbia Gas) and Columbia Gulf Transmission, LLC (Columbia Gulf) (Note 15).

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:

- valuation of Keystone XL assets and Class C Interests (Note 7)
- recoverability and depreciation rates of plant, property and equipment (Note 10)
- allocation of consideration to lease and non-lease components in a contract that contains a lease (Note 11)
- assumptions used to measure the carrying amount of and expected credit losses on net investment in leases and certain contract assets (Notes 11 and 29)
- fair value of equity investments not otherwise noted above (Note 12)
- carrying value of regulatory assets and liabilities (Note 14)
- assumptions used to measure the environmental remediation liability from the Keystone pipeline rupture (Note 18)
- recognition of asset retirement obligations (Note 19)
- 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 20)
- assumptions used to measure retirement and other post-retirement benefit obligations (Note 28)
- fair value of financial instruments (Note 29)
- fair value of Fluvanna Wind Farm and Blue Cloud Wind Farm (Texas Wind Farms) assets (Note 31)
- commitments and provisions for contingencies and guarantees (Note 32).

TC Energy continues to assess the impact of climate change 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 and liquids 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 liquids pipelines as well as 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. RRA is not applicable to the Company's liquids pipelines as the regulators' decisions regarding operations and tolls on those systems generally do not have an impact on timing of recognition of revenues and expenses.

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 and liquids 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 crude oil, 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

The Company is contracted to provide pipeline construction services to a partially-owned entity for a development fee. The development fee is considered variable consideration due to refund provisions in the contract. The Company recognizes its estimate of the most likely amount of the variable consideration to which it will be entitled. The development fee is recognized over time as the services are 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. 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 certain leased pipelines. Revenues earned from these services are recognized ratably over the term of the contract.

Liquids Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's liquids pipelines are generated mainly from providing customers with firm capacity arrangements to transport crude oil. The performance obligation in these contracts is the reservation of a specified amount of capacity together with the transportation of crude oil on a monthly basis. Revenues earned from these arrangements are recognized ratably over the term of the contract regardless of the amount of crude oil that is transported. Revenues for interruptible or volumetric-based services are recognized when the service is performed. Liquids pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the crude oil that it transports for customers.

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 crude oil in transit, 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.

Liquids Pipelines

Plant, property and equipment for liquids pipelines is carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and pumping equipment are depreciated at annual rates ranging from two per cent to 2.5 per cent and other plant and equipment are depreciated at various rates reflecting their estimated useful lives. The cost of these assets includes interest capitalized during construction. When liquids pipelines retire plant, property and equipment from service, the original book cost and related accumulated depreciation are derecognized and any gain or loss is recorded in net income.

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 and liquids tank terminals 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 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 substantively related to its power generation facilities. The scope and timing of asset retirements related to the Company's natural gas and liquids 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, it records an asset 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 assets or liabilities and are refunded to or collected from ratepayers 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

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 the annual period 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 does not expect this guidance to have a material impact on the Company's consolidated financial statements.

Segment Reporting

In November 2023, the 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 is effective for annual periods beginning January 1, 2024 and interim periods beginning January 1, 2025. Early adoption is permitted and the guidance is applied retrospectively. The Company is currently assessing the impact of the standard on the Company's consolidated financial statements.

Leases

In March 2023, the FASB issued new guidance that clarified the accounting for leasehold improvements associated with common control leases. The guidance requires all lessees to amortize leasehold improvements associated with common control leases over their useful life to the common control group and account for them as a transfer of assets between entities under common control at the end of the lease. Additional disclosures are required when the useful life of leasehold improvements to the common control group exceeds the related lease term. This new guidance is effective January 1, 2024 and can be applied either prospectively or retrospectively, with early application permitted. The Company will adopt the guidance on a prospective basis starting January 1, 2024, and it is not expected to have a material impact on the Company's consolidated financial statements.

4. 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 proposed spinoff of its Liquids Pipelines business (the spinoff Transaction) and on November 8, 2023 the Company communicated that the name of the new Liquids Pipelines business would be South Bow Corporation (South Bow). In addition to TC Energy shareholder and court approvals, the spinoff Transaction is subject to receipt of favourable tax rulings from Canadian and U.S. tax authorities, receipt of necessary regulatory approvals, and satisfaction of other customary closing conditions. TC Energy expects that the spinoff Transaction will be completed in the second half of 2024.

Under the spinoff Transaction, TC Energy shareholders will retain their current ownership in TC Energy's common shares and receive a pro-rata allocation of common shares in South Bow. The determination of the number of common shares in South Bow to be distributed to TC Energy shareholders will be determined prior to the closing of the spinoff Transaction. The spinoff Transaction is expected to be tax free to TC Energy's Canadian and U.S. shareholders.

For the year ended December 31, 2023, the Company incurred pre-tax Liquids Pipelines business separation costs of $40 million ($34 million after tax) with respect to the spinoff Transaction, which included internal costs related to separation activities, legal, tax, audit and other consulting fees recorded in Plant operating costs and other in the Consolidated statement of income.

5. SEGMENTED INFORMATION

year ended December 31, 2023 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Energy Solutions	Corporate [1]	Total
Revenues	5,173	6,229	846	2,667	1,019	—	15,934
Intersegment revenues	—	101	—	—	22	(123) [2]	—
	5,173	6,330	846	2,667	1,041	(123)	15,934
Income (loss) from equity investments	220	324	78	67	688	—	1,377
Impairment of equity investment	(2,100)	—	—	—	—	—	(2,100)
Plant operating costs and other	(1,756)	(1,660)	(39)	(836)	(603)	7 [2]	(4,887)
Commodity purchases resold	—	(56)	—	(437)	(24)	—	(517)
Property taxes	(302)	(473)	—	(116)	(6)	—	(897)
Depreciation and amortization	(1,325)	(934)	(89)	(338)	(92)	—	(2,778)
Goodwill and asset impairment charges and other	—	—	—	4	—	—	4
Segmented Earnings (Losses)	(90)	3,531	796	1,011	1,004	(116)	6,136
Interest expense							(3,263)
Allowance for funds used during construction							575
Foreign exchange gains (losses), net							320
Interest income and other							242
Income (Loss) before Income Taxes							4,010
Income tax (expense) recovery							(942)
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[3]							
Capital expenditures	2,953	2,536	2,292	49	144	33	8,007
Capital projects in development	—	—	—	—	142	—	142
Contributions to equity investments	3,231	124	—	—	794	—	4,149
	6,184	2,660	2,292	49	1,080	33	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 Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

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

year ended December 31, 2022 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Energy Solutions	Corporate [1]	Total
Revenues	4,764	5,933	688	2,668	924	—	14,977
Intersegment revenues	—	132	—	—	12	(144) [2]	—
	4,764	6,065	688	2,668	936	(144)	14,977
Income (loss) from equity investments	18	292	122	55	539	28 [3]	1,054
Impairment of Equity Investment	(3,048)	—	—	—	—	—	(3,048)
Plant operating costs and other	(1,679)	(1,856)	(221)	(756)	(544)	124 [2]	(4,932)
Commodity purchases resold	—	—	—	(512)	(22)	—	(534)
Property taxes	(297)	(426)	—	(121)	(4)	—	(848)
Depreciation and amortization	(1,198)	(887)	(98)	(329)	(72)	—	(2,584)
Goodwill and asset impairment charges and other	—	(571)	—	118	—	—	(453)
Segmented Earnings (Losses)	(1,440)	2,617	491	1,123	833	8	3,632
Interest expense							(2,588)
Allowance for funds used during construction							369
Foreign exchange gains (losses), net[3]							(185)
Interest income and other							146
Income (Loss) before Income Taxes							1,374
Income tax (expense) recovery							(589)
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[4]							
Capital expenditures	3,274	2,137	1,027	106	93	41	6,678
Capital projects in development	—	—	—	—	49	—	49
Contributions to equity investments[5]	1,445	—	—	37	752	—	2,234
	4,719	2,137	1,027	143	894	41	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 Plant operating costs and other 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 13, Loans receivable from affiliates, for additional information.

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

5 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 13, Loans receivable from affiliates, for additional information.

year ended December 31, 2021 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Energy Solutions	Corporate [1]	Total
Revenues	4,519	5,233	605	2,306	724	—	13,387
Intersegment revenues	—	145	—	—	14	(159) [2]	—
	4,519	5,378	605	2,306	738	(159)	13,387
Income (loss) from equity investments	12	244	119	71	411	41 [3]	898
Plant operating costs and other	(1,567)	(1,393)	(55)	(700)	(455)	72 [2]	(4,098)
Commodity purchases resold	—	—	(3)	(84)	—	—	(87)
Property taxes	(289)	(367)	—	(113)	(5)	—	(774)
Depreciation and amortization	(1,226)	(791)	(109)	(318)	(78)	—	(2,522)
Goodwill and asset impairment charges and other	—	—	—	(2,775)	—	—	(2,775)
Net gain (loss) on sale of assets	—	—	—	13	17	—	30
Segmented Earnings (Losses)	1,449	3,071	557	(1,600)	628	(46)	4,059
Interest expense							(2,360)
Allowance for funds used during construction							267
Foreign exchange gains (losses), net[3]							10
Interest income and other							190
Income (Loss) before Income Taxes							2,166
Income tax (expense) recovery							(120)
Net Income (Loss)							2,046
Net (income) loss attributable to non-controlling interests							(91)
Net Income (Loss) Attributable to Controlling Interests							1,955
Preferred share dividends							(140)
Net Income (Loss) Attributable to Common Shares							1,815
Capital Spending[4]							
Capital expenditures	2,629	2,611	129	488	32	35	5,924
Contributions to equity investments	108	209	—	83	810	—	1,210
	2,737	2,820	129	571	842	35	7,134

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 Plant operating costs and other 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. Refer to Note 13, Loans receivable from affiliates, for additional information.

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

December 31 llions of Canadian $)	2023	2022
tal Assets by Segment		
nadian Natural Gas Pipelines	**29,782**	27,456
S. Natural Gas Pipelines	**50,499**	50,038
xico Natural Gas Pipelines	**12,003**	9,231
uids Pipelines	**15,490**	15,587
wer and Energy Solutions	**9,525**	8,272
rporate	**7,735**	3,764
	125,034	114,348

Geographic Information

year ended December 31 (millions of Canadian $)	2023	2022	2021
Revenues			
Canada – domestic	**5,360**	4,942	4,603
Canada – export	**1,403**	1,322	1,226
United States	**8,325**	8,025	6,953
Mexico	**846**	688	605
	15,934	14,977	13,387

at December 31 (millions of Canadian $)	2023	2022
Plant, Property and Equipment		
Canada	**28,583**	27,232
United States	**44,609**	43,505
Mexico	**7,377**	5,203
	80,569	75,940

6. REVENUES

Disaggregation of Revenues

year ended December 31, 2023 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Energy Solutions	Total
Revenues from contracts with customers						
Capacity arrangements and transportation	**5,141**	**5,107**	**442**	**2,115**	**—**	**12,805**
Power generation	**—**	**—**	**—**	**—**	**427**	**427**
Natural gas storage and other[1,2]	**32**	**874**	**125**	**3**	**363**	**1,397**
	5,173	**5,981**	**567**	**2,118**	**790**	**14,629**
Sales-type lease income[3]	**—**	**—**	**279**	**—**	**—**	**279**
Other revenues[4]						
	—	**248**	**—**	**549**	**229**	**1,026**
	5,173	**6,229**	**846**	**2,667**	**1,019**	**15,934**

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 11, Leases, for additional information.
3 Represents the sales-type lease income on the in-service TGNH pipelines. Refer to Note 11, Leases, for additional information.
4 Other revenues include income from the Company's operating lease arrangements, marketing activities and financial instruments. Refer to Note 11, Leases, and Note 29, Risk management and financial instruments, for additional information.

year ended December 31, 2022 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Energy Solutions	Total
Revenues from contracts with customers						
Capacity arrangements and transportation	4,696	4,621	507	1,983	—	11,807
Power generation	—	—	—	—	490	490
Natural gas storage and other[1,2]	68	1,298	54	4	391	1,815
	4,764	5,919	561	1,987	881	14,112
Sales-type lease income[3]	—	—	127	—	—	127
Other revenues[4,5]						
	—	14	—	681	43	738
	4,764	5,933	688	2,668	924	14,977

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 11, Leases, for additional information.
3 Represents the sales-type lease income on the in-service TGNH pipelines. Refer to Note 11, Leases, for additional information.
4 Other revenues include income from the Company's operating lease arrangements, marketing activities and financial instruments. Refer to Note 11, Leases, and Note 29, Risk management and financial instruments, for additional information.
5 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 14, Rate-regulated businesses, for additional information.

ır ended December 31, 2021 llions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Energy Solutions	Total
venues from contracts with customers						
apacity arrangements and transportation	4,432	4,139	576	2,025	—	11,172
ɔwer generation	—	—	—	—	324	324
atural gas storage and other[1]	87	1,057	29	5	278	1,456
	4,519	5,196	605	2,030	602	12,952
ıer revenues[2,3]						
	—	37	—	276	122	435
	4,519	5,233	605	2,306	724	13,387

1 Includes $87 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 Other revenues include income from the Company's operating lease arrangements, marketing activities and financial instruments. Refer to Note 11, Leases, and Note 29, Risk management and financial instruments, for additional information.
3 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from U.S. Tax Reform. Refer to Note 14, Rate-regulated businesses, for additional information.

Contract Balances

at December 31 (millions of Canadian $)	2023	2022	Affected line item on the Consolidated balance sheet
Receivables from contracts with customers	**1,832**	1,907	Accounts receivable
Contract assets (Note 9)	**151**	155	Other current assets
Long-term contract assets (Note 16)	**457**	355	Other long-term assets
Contract liabilities[1] (Note 18)	**69**	62	Accounts payable and other
Long-term contract liabilities[1] (Note 19)	**12**	32	Other long-term liabilities

1 During the year ended December 31, 2023, $ 64 million (2022 – $ 51 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 TGNH pipelines 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, 2023, future revenues from long-term pipeline capacity arrangements and transportation as well as natural gas storage and other contracts extending through 2055 are approximately $22.9 billion, of which approximately $4.9 billion is expected to be recognized in 2024.

A significant portion of the Company's revenues are considered constrained and therefore not included in the future revenue amounts above as the Company uses the following practical expedients:

- right to invoice practical expedient – applied to all U.S. and certain Mexico rate-regulated natural gas pipeline capacity arrangements and flow-through revenues
- variable consideration practical expedient – applied to the following variable revenues:
  - interruptible transportation service revenues as volumes cannot be estimated
  - liquids pipelines capacity revenues based on volumes transported
  - power generation revenues related to market prices that are subject to factors outside the Company's influence
- contracts for a duration of one year or less. In addition, future revenues from the Company's Canadian natural gas pipelines' regulated firm capacity contracts include fixed revenues only for the time periods that approved tolls under current rate settlements are in effect and certain. Future revenues exclude lease income from the Company's Mexico natural gas pipelines on projects that have not been placed into service.

7. KEYSTONE XL

Asset Impairment Charge and Other

Following the revocation of the Presidential Permit for the Keystone XL pipeline project on January 20, 2021, the Company terminated the Keystone XL pipeline project and evaluated the Keystone XL investment for impairment in 2021. As a result, the Company determined that the carrying amount of these assets within the Liquids Pipelines segment was no longer fully recoverable and recognized an asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations related to termination activities, of $2,775 million ($2,134 million after tax) for the year ended December 31, 2021. The asset impairment charge was based on the excess of the carrying value of $3,301 million over the estimated fair value of $175 million.

year ended December 31, 2021 (millions of Canadian $)	Estimated Fair Value of Plant, Property and Equipment	Asset impairment charge and other	
		Pre tax	After tax
Asset impairment charge			
Plant and equipment	**175**	**412**	**312**
Related capital projects in development	**—**	**230**	**175**
Other capitalized costs	**—**	**2,158**	**1,642**
Capitalized interest	**—**	**326**	**248**
	175	**3,126**	**2,377**
Other			
Contractual recoveries	**n/a**	**(693)**	**(525)**
Contractual and legal obligations related to termination activities	**n/a**	**342**	**282**
	175	**2,775**	**2,134**

The estimated fair value of $175 million at December 31, 2021 related to plant and equipment was based on the price that was expected to be received from selling these assets in their current condition and is updated as required. The initial key assumptions used in the determination of selling price included an estimated two-year disposal period and current energy market demand. The valuation considered a variety of potential selling prices based on various markets that could be used to dispose of these assets and required the use of unobservable inputs. As a result, the fair value is classified in Level III of the fair value hierarchy.

In 2023, the Company received $10 million (2022 – $571 million) towards its contractual recoveries, resulting in a remaining balance of $117 million at December 31, 2023 (December 31, 2022 – $130 million).

In 2022, the Company revised its estimate of contractual and legal obligations related to termination activities based on a review of costs and commitments incurred, which resulted in a $54 million reduction to the asset impairment charge. No revision to the estimate was made in 2023. The Company paid $2 million in 2023 (2022 – $24 million; 2021 – $192 million) towards contractual and legal obligations related to termination activities. At December 31, 2023, the remaining balance accrued was $45 million (December 31, 2022 – $48 million).

In 2023, the Company sold plant and equipment with a carrying value of approximately $63 million (2022 – $25 million; 2021 – $16 million), resulting in a gain of $36 million (2022 – $64 million; 2021 – nil) recorded in Goodwill and asset impairment charges and other in the Consolidated statement of income.

As part of the Keystone XL impairment charge and other, the Company recorded a $14 million income tax recovery in 2023 (2022 – $96 million expense) in relation to the termination of the Keystone XL pipeline project.

Redeemable Non-Controlling Interest and Long-Term Debt

In March 2020, the Company announced that it would proceed with construction of the Keystone XL pipeline. As part of the funding plan, the Government of Alberta invested $1,033 million in the form of Class A Interests in the year ended December 31, 2020.

On January 4, 2021, the Company put in place a US$4.1 billion project-level credit facility to support construction of the Keystone XL pipeline, that was fully guaranteed by the Government of Alberta and non-recourse to the Company. On January 8, 2021, the Company exercised its call right with the Government of Alberta in accordance with contractual terms and paid $633 million (US$497 million) to repurchase the Government of Alberta Class A Interests in certain Keystone XL subsidiaries. This transaction was funded by draws on the project-level credit facility. For the year ended December 31, 2021, the Company made draws under the Keystone XL project-level credit facility totaling $1,028 million (US$849 million). Following the cancellation of the Keystone XL pipeline project, the Government of Alberta repaid the full outstanding balance in June 2021 in accordance with the terms of the guarantee, and the credit facility was subsequently terminated. Additionally, in June 2021, the Company repurchased the remaining Government of Alberta Class A Interests for a nominal amount, which was accounted for as an equity transaction and resulted in $394 million recognized in Additional paid-in capital. As part of this arrangement, TC Energy issued $91 million of Class C Interests in the Keystone XL subsidiaries which entitled the Government of Alberta to future liquidation proceeds from specified Keystone XL project assets. The entire $91 million was recorded (net of distributions) in Accounts payable and other on the Consolidated balance sheet. During 2023, it was determined that the Company would exceed the $91 million of Class C distributions and the Company increased the Class C Interests carrying value by $32 million with a corresponding amount recorded in Goodwill and asset impairment charges and other in the Consolidated statement of income. Termination of the project-level credit facility, net of the issuance of Class C Interests, resulted in $937 million ($737 million after tax) recorded to Additional paid-in capital in 2021. For the year ended December 31, 2023, the Company made Class C distributions to the Government of Alberta of $49 million (2022 – $43 million; 2021 – $16 million).

8. COASTAL GASLINK

Impairment of Equity Investment in Coastal GasLink LP

In July 2022, amended agreements were executed between Coastal GasLink LP, LNG Canada, TC Energy and its Coastal GasLink LP partners (collectively, the July 2022 agreements). These amendments revised the commercial terms between LNG Canada and Coastal GasLink LP, as well as funding provisions between the partners of Coastal GasLink LP.

With the expectation that additional equity contributions under a subordinated loan agreement between TC Energy and the Coastal GasLink LP partners will be predominantly funded by TC Energy as limited partner of Coastal GasLink LP, in accordance with the July 2022 agreements, the Company completed valuation assessments during the first three quarters of 2023 and concluded that, for each period an assessment was performed, the fair value of its investment in Coastal GasLink LP was below its carrying value and that these were other-than-temporary impairments. As a result, a pre-tax impairment charge of $2,100 million ($1,943 million after tax) was recognized during the year ended December 31, 2023 in Impairment of equity investment in the Consolidated statement of income in the Canadian Natural Gas Pipelines segment (2022 – $3,048 million; $2,643 million after tax). The carrying value of the investment in Coastal GasLink LP was $294 million at December 31, 2023 (2022 – nil), which reflects the balance of amounts, net of impairments, drawn on the subordinated loan to date at December 31, 2023 and other changes to TC Energy's equity investment. The impairment charge reflected the net impact of $2,020 million drawn on and a $250 million repayment of the subordinated loan for the nine months ended September 30, 2023, along with TC Energy's proportionate share of unrealized gains and losses on interest rate derivatives in Coastal GasLink LP and other changes to the equity investment. The cumulative pre-tax impairment charge recognized at December 31, 2023 is $5,148 million ($4,586 million after tax).

A deferred income tax recovery was recognized on the pre-tax impairment charge, net of certain unrealized tax losses not recognized. The impairment of the subordinated loan resulted in unrealized non-taxable capital losses that are not recognized. Refer to Note 20, Income taxes, for additional information.

At December 31, 2023, TC Energy expects to fund an additional $0.9 billion related to the capital cost estimates to complete the Coastal GasLink pipeline, which is consistent with the capital cost profile that was included in the September 30, 2023 impairment calculation. At December 31, 2023, there were no events or changes in circumstances since September 30, 2023 indicating a significant adverse impact on the estimated fair value of the Company's investment in Coastal GasLink LP.

The fair value of TC Energy's investment in Coastal GasLink LP at September 30, 2023 and December 31, 2022 was estimated using a 40-year discounted cash flow model and is classified as a Level III fair value measurement.

The discounted cash flow is most sensitive to assumptions related to the capital cost estimates for the Coastal GasLink pipeline of approximately $14.5 billion (2022 – $14.5 billion), discount rate and long-term financing plans.

Other assumptions included in the discounted cash flow model include contractually agreed upon terms and extension provisions in the TSAs between Coastal GasLink LP and the LNG Canada participants, potential expansion projects and estimated completion date.

Subordinated Loan Agreement

In 2021, TC Energy entered into a subordinated loan agreement with Coastal GasLink LP. This loan agreement was amended as part of the July 2022 agreements, and subsequent draws on this loan by Coastal GasLink LP will be provided through an interest-bearing loan, subject to a floating market-based interest rate to fund the capital cost to complete the Coastal GasLink pipeline. Committed capacity under the subordinated loan agreement between TC Energy and Coastal GasLink LP was $3.4 billion, with $2.5 billion drawn on the loan at December 31, 2023.

Any amounts outstanding on the loan will be repaid by Coastal GasLink LP to TC Energy once final project costs are known, which will be determined after the pipeline is placed into service. Coastal GasLink LP partners, including TC Energy, will contribute equity to Coastal GasLink LP to ultimately fund Coastal GasLink LP's repayment of this subordinated loan to TC Energy. The Company expects that these additional equity contributions will be predominantly funded by TC Energy. Amounts drawn on this loan subsequent to amended agreements executed in July 2022 are accounted for as in-substance equity contributions and are presented as Contributions to equity investments on the Company's Consolidated statement of cash flows. Interest and principal repayments on this loan, which are expected to be predominantly funded by TC Energy, will be accounted for as an equity investment distribution to the Company once received.

The table below reflects the changes in this loan receivable balance.

at December 31 (millions of Canadian $)	2023	2022
Outstanding balance at beginning of year	**250**	238
Issuances	**2,520**	112
Repayments	**(250)**	(100)
Outstanding balance at end of year	**2,520**	250
Impairment during the year	**(2,020)**	(250)
Carrying value at end of year	**500**	—

9. OTHER CURRENT ASSETS

at December 31 (millions of Canadian $)	2023	2022
Fair value of derivative contracts (Note 29)	**1,285**	614
Current portion of net investment in leases (Note 11)	**306**	291
Contract assets (Note 6)	**151**	155
Current portion of Keystone environmental provision recovery (Note 18)	**150**	410
Cash provided as collateral	**120**	106
Emissions credits	**94**	36
Prepaid expenses	**92**	118
Keystone XL contractual recoveries (Note 7)	**83**	86
Regulatory assets (Note 14)	**76**	67
Keystone XL assets held for sale	**58**	122
Other	**88**	147
	2,503	2,152

10. PLANT, PROPERTY AND EQUIPMENT

at December 31	2023			2022		
(millions of Canadian $)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Canadian Natural Gas Pipelines						
NGTL System						
Pipeline	**20,232**	**6,855**	**13,377**	18,119	6,285	11,834
Compression	**6,603**	**2,349**	**4,254**	6,265	2,224	4,041
Metering and other	**1,589**	**830**	**759**	1,518	769	749
	28,424	**10,034**	**18,390**	25,902	9,278	16,624
Under construction	**787**	**—**	**787**	1,552	—	1,552
	29,211	**10,034**	**19,177**	27,454	9,278	18,176
Canadian Mainline						
Pipeline	**10,729**	**7,996**	**2,733**	10,472	7,852	2,620
Compression	**4,437**	**3,354**	**1,083**	4,328	3,247	1,081
Metering and other	**729**	**308**	**421**	692	285	407
	15,895	**11,658**	**4,237**	15,492	11,384	4,108
Under construction	**147**	**—**	**147**	269	—	269
	16,042	**11,658**	**4,384**	15,761	11,384	4,377
Other Canadian Natural Gas Pipelines[1]						
Other	**2,846**	**1,682**	**1,164**	1,984	1,624	360
Under construction	**23**	**—**	**23**	455	—	455
	2,869	**1,682**	**1,187**	2,439	1,624	815
	48,122	**23,374**	**24,748**	45,654	22,286	23,368
U.S. Natural Gas Pipelines						
Columbia Gas						
Pipeline	**12,952**	**1,247**	**11,705**	12,471	1,069	11,402
Compression	**5,310**	**559**	**4,751**	5,190	495	4,695
Metering and other	**4,074**	**372**	**3,702**	4,026	346	3,680
	22,336	**2,178**	**20,158**	21,687	1,910	19,777
Under construction	**771**	**—**	**771**	659	—	659
	23,107	**2,178**	**20,929**	22,346	1,910	20,436
ANR						
Pipeline	**2,117**	**657**	**1,460**	2,066	641	1,425
Compression	**3,928**	**773**	**3,155**	3,785	734	3,051
Metering and other	**1,625**	**458**	**1,167**	1,666	440	1,226
	7,670	**1,888**	**5,782**	7,517	1,815	5,702
Under construction	**404**	**—**	**404**	328	—	328
	8,074	**1,888**	**6,186**	7,845	1,815	6,030

at December 31	2023			2022		
(millions of Canadian $)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Other U.S. Natural Gas Pipelines						
Columbia Gulf	**3,600**	**256**	**3,344**	3,511	224	3,287
GTN	**2,992**	**1,295**	**1,697**	2,964	1,239	1,725
Great Lakes	**2,359**	**1,401**	**958**	2,367	1,387	980
Other[2]	**2,071**	**800**	**1,271**	1,928	760	1,168
	11,022	**3,752**	**7,270**	10,770	3,610	7,160
Under construction	**584**	**—**	**584**	328	—	328
	11,606	**3,752**	**7,854**	11,098	3,610	7,488
	42,787	**7,818**	**34,969**	41,289	7,335	33,954
Mexico Natural Gas Pipelines[3]						
Pipeline	**2,280**	**387**	**1,893**	2,299	348	1,951
Compression	**370**	**79**	**291**	374	59	315
Metering and other	**482**	**123**	**359**	487	113	374
	3,132	**589**	**2,543**	3,160	520	2,640
Under construction	**4,823**	**—**	**4,823**	2,547	—	2,547
	7,955	**589**	**7,366**	5,707	520	5,187
Liquids Pipelines						
Keystone Pipeline System						
Pipeline	**9,569**	**2,212**	**7,357**	9,777	2,056	7,721
Pumping equipment	**1,096**	**312**	**784**	1,064	288	776
Tanks and other	**3,658**	**913**	**2,745**	3,723	859	2,864
	14,323	**3,437**	**10,886**	14,564	3,203	11,361
Under construction	**54**	**—**	**54**	96	—	96
	14,377	**3,437**	**10,940**	14,660	3,203	11,457
Intra-Alberta Pipelines	**203**	**25**	**178**	199	19	180
	14,580	**3,462**	**11,118**	14,859	3,222	11,637
Power and Energy Solutions						
Natural Gas Power Generation	**1,239**	**637**	**602**	1,260	642	618
Natural Gas Storage and Other	**845**	**256**	**589**	820	238	582
Renewable Power Generation	**581**	**19**	**562**	—	—	—
	2,665	**912**	**1,753**	2,080	880	1,200
Under construction	**153**	**—**	**153**	80	—	80
	2,818	**912**	**1,906**	2,160	880	1,280
Corporate	**909**	**447**	**462**	900	386	514
	117,171	**36,602**	**80,569**	110,569	34,629	75,940

1 Includes Foothills, Ventures LP and Great Lakes Canada.

2 Includes Portland, North Baja, Tuscarora, Crossroads and mineral rights business.

3 During the year ended December 31, 2023, the Company derecognized $ 407 million (2022 – $2,319 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 11, Leases, for additional information.

11. 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 $)	2023	2022
Operating lease cost[1]	**118**	106
Sublease income	**(4)**	(5)
Net operating lease cost	**114**	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 $)	2023	2022
Cash paid for amounts included in the measurement of operating lease liabilities	**72**	67
ROU assets obtained in exchange for new operating lease liabilities	**84**	49

at December 31	2023	2022
Weighted average remaining lease term	**13 years**	8 years
Weighted average discount rate	**3.3 %**	3.5 %

Maturities of operating lease liabilities are as follows:

at December 31 (millions of Canadian $)	2023	2022
Less than one year	**72**	68
One to two years	**68**	65
Two to three years	**66**	62
Three to four years	**59**	60
Four to five years	**58**	54
More than five years	**225**	187
Total operating lease payments	**548**	496
Imputed interest	**(89)**	(63)
Operating lease liabilities	**459**	433

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

at December 31 (millions of Canadian $)	2023	2022
Accounts payable and other	**58**	54
Other long-term liabilities (Note 19)	**401**	379
	459	433

As at December 31, 2023, the carrying value of the ROU assets recorded under operating leases was $437 million (2022 – $415 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 2024 and 2026.

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 Company also leases liquids tanks which are accounted for as operating leases.

The fixed portion of the operating lease income recorded by the Company for the year ended December 31, 2023 was $116 million (2022 – $118 million; 2021 – $126 million).

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

at December 31 (millions of Canadian $)	2023	2022
Less than one year	**113**	113
One to two years	**94**	111
Two to three years	**70**	94
Three to four years	**—**	70
	277	388

The cost and accumulated depreciation for facilities accounted for as operating leases was $796 million and $370 million, respectively, at December 31, 2023 (2022 – $802 million and $360 million, respectively).

Sales-Type Leases

On August 4, 2022, TC Energy announced a strategic alliance with Mexico’s state-owned electric utility, the Comisión Federal de Electricidad (CFE), for the development of new natural gas infrastructure in central and southeast Mexico. This alliance consolidates previous TSAs executed between TC Energy’s Mexico-based subsidiary TGNH and the CFE in connection with the Company's natural gas pipeline assets in central Mexico (including the Tamazunchale, Villa de Reyes and Tula pipelines) under a single, U.S. dollar-denominated take-or-pay TSA that extends through 2055.

The consolidated TSA contains a lease with multiple lease and non-lease components. The lease components represent the capacity available to the CFE provided by the in-service pipelines which, at December 31, 2023, included the Tamazunchale pipeline, the north and lateral sections of the Villa de Reyes pipeline and the east section of the Tula pipeline. The non-lease components represent the Company’s services with respect to operation and maintenance of the TGNH pipelines in service.

The consolidated TSA provides the CFE with substantially all of the economic benefits from the use of each identified in-service asset, therefore, the lease arrangements in the consolidated TSA are classified as sales-type leases.

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 2023, the Company recognized an additional $407 million in net investment in leases (2022 – $2,319 million) to reflect sales type-leases placed into service. At the inception of the lease term, the Company applied judgment to determine that the fair value of the underlying assets approximated the carrying value and residual value of the lease based on the rate-regulated nature of the assets within the TGNH system.

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 $)	2023	2022
Net Investment in Leases		
Minimum lease payments	**9,627**	9,457
Unearned lease income	**(7,006)**	(7,132)
Lease receivable	**2,621**	2,325
Expected credit loss provision[1]	**(76)**	(150)
Present value of unguaranteed residual value	**24**	11
	2,569	2,186
Current portion included in Other current assets (Note 9)	**(306)**	(291)
	2,263	1,895

1 Includes nil (2022 – $1 million) of foreign currency translation losses.

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

at December 31 (millions of Canadian $)	2023	2022
Less than one year	**305**	291
One to two years	**305**	291
Two to three years	**305**	291
Three to four years	**305**	291
Four to five years	**305**	291
More than five years	**8,102**	8,002
	9,627	9,457

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

For the year ended December 31, 2023, the Company recorded $279 million (2022 – $127 million) of sales-type lease income in Mexico Natural Gas Pipelines revenues.

For the year ended December 31, 2023, the Company recorded a $73 million ECL recovery (2022 – an expense of $149 million; 2021 – nil) in Plant operating costs and other relating to net investment in leases. Refer to Note 29, Risk management and financial instruments, for additional information.

12. EQUITY INVESTMENTS

(millions of Canadian $)	Ownership Interest at December 31, 2023	Income (Loss) from Equity Investments year ended December 31 2023	2022	2021	Equity Investments at December 31 2023	2022
Canadian Natural Gas Pipelines						
TQM[1]	50.0 %	**17**	17	12	**166**	165
Coastal GasLink[1]	35.0 %	**203**	1	—	**294**	—
U.S. Natural Gas Pipelines						
Northern Border	50.0 %	**101**	92	80	**599**	516
Millennium	47.5 %	**109**	103	91	**476**	500
Iroquois	50.0 %	**98**	77	55	**227**	237
Other	Various	**16**	20	18	**120**	122
Mexico Natural Gas Pipelines						
Sur de Texas	60.0 %	**78**	150	160	**1,078**	1,050
Liquids Pipelines						
Grand Rapids[1]	50.0 %	**53**	54	54	**932**	964
Port Neches Link LLC[2,3]	74.9 %	**13**	—	—	**124**	149
HoustonLink Pipeline[1]	50.0 %	**1**	1	1	**18**	19
Northern Courier[1,4]	nil	**—**	—	16	**—**	—
Power and Energy Solutions						
Bruce Power[1]	48.3 %	**690**	537	411	**6,242**	5,783
Other	Various	**(2)**	2	—	**38**	30
		1,377	1,054	898	**10,314**	9,535

1 Classified as a VIE. Refer to Note 33, Variable interest entities, for additional information.
2 Classified as a VIE in 2021.
3 In December 2023, TC Energy sold a 20.1 per cent equity interest in Port Neches Link LLC.
4 In November 2021, TC Energy sold its remaining 15 per cent equity interest in Northern Courier. Refer to Note 31, Acquisitions and dispositions, 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 LNG Canada facility by the end of 2023. These milestones entitle Coastal GasLink LP to receive a $200 million incentive payment from LNG Canada. In accordance with the contractual terms between the Coastal GasLink LP partners, the amount accrues in full to TC Energy as the project developer and was settled through a cash distribution on February 12, 2024. The Company recognized the incentive payment as Income (loss) from equity investments in the Consolidated statement of income for the year ended December 31, 2023 and recorded a corresponding amount in Accounts receivable on the Consolidated balance sheet.

Impairment of Equity Investment

In the fourth quarter of 2022, the Company announced that a material increase in the Coastal GasLink pipeline project costs was expected. On February 1, 2023, Coastal GasLink LP announced an increase in the revised capital cost of the Coastal GasLink pipeline project. The increase in project costs and the Company's corresponding funding requirements were indicators that a decrease in the value of the Company's equity investment had occurred. As a result, the Company completed a valuation assessment and concluded that the fair value of TC Energy's investment was below its carrying value at December 31, 2022. The Company completed valuation assessments at each of the first three quarters of 2023 and concluded that an other-than-temporary impairment of its investment had occurred. This resulted in a pre-tax impairment charge of $2,100 million ($1,943 million after tax) and $3,048 million ($2,643 million after tax) recorded in the year ended December 31, 2023 and 2022, respectively. Refer to Note 8, Coastal GasLink, for additional information.

Distributions and Contributions

Distributions received from equity investments and contributions made to equity investments for the years ended December 31, 2023, 2022 and 2021 were as follows:

year ended December 31			
(millions of Canadian $)	**2023**	**2022**	**2021**
Distributions			
Distributions received from operating activities of equity investments	**1,254**	1,025	975
Sur de Texas debt repayments[1,2]	**—**	2,404	73
Other[1]	**23**	228	—
	1,277	3,657	1,048
Contributions[1]			
Contributions to Coastal GasLink	**3,231**	1,414	92
Sur de Texas debt financing[2]	**—**	1,199	—
Contributions made to other equity investments	**918**	820	1,118
	4,149	3,433	1,210

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

2 Represents TC Energy's proportionate share of the Sur de Texas debt financing requirements and subsequent repayments. Refer to Note 13, Loans receivable from affiliates, for additional information.

Summarized Financial Information of Equity Investments

year ended December 31			
(millions of Canadian $)	**2023**	**2022**	**2021**
Income			
Revenues	**6,425**	5,891	5,447
Operating and other expenses	**(3,450)**	(3,390)	(3,293)
Net income	**2,584**	2,147	1,859
Net income attributable to TC Energy	**1,377**	1,054	898

at December 31		
(millions of Canadian $)	**2023**	**2022**
Balance Sheet		
Current assets	**3,526**	3,414
Non-current assets	**42,933**	37,713
Current liabilities	**(2,431)**	(2,856)
Non-current liabilities	**(21,895)**	(17,690)

At December 31, 2023, the cumulative carrying value of the Company's equity investments was $183 million (2022 – $299 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 8, Coastal GasLink, for additional information.

13. 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 and operate the Coastal GasLink pipeline.

Subordinated Demand Revolving Credit Facility

The Company has a subordinated demand revolving credit facility with Coastal GasLink LP to provide additional short-term liquidity and funding flexibility to the project. The facility bears interest at a floating market-based rate and has a capacity of $100 million (2022 – $100 million) with no outstanding balance at December 31, 2023 and 2022. This revolver was not impacted by the impairment charges recognized to date.

Subordinated Loan Agreement

In 2021, TC Energy entered into a subordinated loan agreement with Coastal GasLink LP, which was amended on July 28, 2022. At December 31, 2023, the total capacity committed by TC Energy under this subordinated loan agreement was $3.4 billion (2022 – $1.3 billion) with an outstanding balance of $2,520 million (2022 – $250 million). In the year ended December 31, 2023, $2,020 million (2022 – $250 million) was impaired. Refer to Note 8, 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 $)	2023	2022	2021	Affected line item in the Consolidated statement of income
Interest income[1]	—	19	87	Interest income and other
Interest expense[2]	—	(19)	(87)	Income (loss) from equity investments
Foreign exchange losses[1]	—	(28)	(41)	Foreign exchange (gains) losses, net
Foreign exchange gains[1]	—	28	41	Income 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 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.

14. 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 (CER Act). The Impact Assessment Agency of Canada continues to assess designated projects.

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.

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

The NGTL System is operating under the 2020-2024 Revenue Requirement Settlement which includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provides 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 its customers.

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 (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 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 reached a settlement with its customers effective February 2021 and received FERC approval in February 2022. As part of the settlement, there is a moratorium on any further rate changes until April 1, 2025. Columbia Gas must file for new rates with an effective date no later than April 1, 2026. Previously accrued rate refund liabilities were refunded to customers, including interest, in second quarter 2022.

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.

ANR Pipeline

ANR Pipeline operated under rates established through a 2016 FERC-approved rate settlement until July 31, 2022. To meet terms of the 2016 settlement, in January 2022, ANR Pipeline filed a Section 4 Rate Case with FERC requesting an increase to maximum transportation rates. In December 2022 ANR Pipeline filed a Stipulation and Agreement of Settlement (2022 ANR Settlement) with FERC. 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. In second quarter 2023, previously accrued rate refund liabilities, including interest, were refunded to customers.

Columbia Gulf

Columbia Gulf operates under a settlement approved by FERC in December 2019 (2019 Columbia Gulf Settlement), which requires Columbia Gulf to file a general rate case under Section 4 of the NGA no later than January 31, 2027. The 2019 Columbia Gulf Settlement included a moratorium that expired in August 2022. In July 2023 Columbia Gulf, in advance of its obligation to file a general rate case from the 2019 Columbia Gulf Settlement, reached a settlement with its customers effective March 1, 2024 and received FERC approval in August 2023 (2023 Columbia Gulf Settlement). As part of the 2023 Columbia Gulf Settlement, there is a moratorium on any 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 settlement approved by FERC in February 2018, which does not include a moratorium; however, Great Lakes was required to file for new rates no later than March 31, 2022.

In March 2022, Great Lakes filed a rate settlement (2022 Great Lakes Settlement) with FERC that satisfies the obligations from the 2017 settlement that Great Lakes file for rates to become effective no later than October 2022. The 2022 Great Lakes Settlement, approved by FERC in April 2022, 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 effective August 2019. Under the terms of this settlement, Tuscarora was required to file for new rates to be effective no later than February 1, 2023. Tuscarora filed a general NGA Section 4 Rate Case with FERC in July 2022, requesting an increase to its maximum rates effective February 1, 2023, subject to refund. On March 24, 2023, Tuscarora filed a Stipulation and Agreement of Settlement with FERC, which was approved on September 6, 2023.

Gas Transmission Northwest

Gas Transmission Northwest (GTN) operates under rates established as part of the FERC-approved rate settlement effective November 18, 2021 (2021 GTN Settlement). The 2021 GTN Settlement satisfies the obligations from the 2015 and 2018 rate settlements that GTN file for rates to become effective no later than January 1, 2022 and extends existing maximum transportation rates at their current levels. GTN's annual depreciation rates remain unchanged. The 2021 GTN Settlement contains a moratorium until December 31, 2023. Additionally, the 2021 GTN Settlement authorizes GTN to recover payments that it incurs in the states of Oregon and Washington for carbon/greenhouse gas-related taxes. GTN is required to file for new rates to become effective no later than April 1, 2024. Accordingly, GTN filed a general NGA Section 4 Rate Case with FERC on September 29, 2023, requesting an increase to GTN's maximum rates to become effective April 1, 2024, and subject to refund.

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 are in compliance with CRE economic regulations that 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)	2023	2022
Regulatory Assets			
Deferred income taxes[1]	n/a	**2,204**	1,817
Operating and debt-service regulatory assets[2]	1	**29**	2
Pensions and other post-retirement benefits[1,3]	n/a	**54**	28
Foreign exchange on long-term debt[1,4]	1-6	**11**	19
Other	n/a	**108**	111
		2,406	1,977
Less: Current portion included in Other current assets (Note 9)		**76**	67
		2,330	1,910
Regulatory Liabilities			
Pipeline abandonment trust balances[5]	n/a	**2,355**	2,014
Deferred income taxes – U.S. Tax Reform[6]	n/a	**1,137**	1,197
Canadian Mainline short-term adjustment and toll-stabilization accounts[7,8]	n/a	**437**	284
Canadian Mainline bridging amortization account[7]	7	**376**	429
Cost of removal[9]	n/a	**351**	337
Deferred income taxes[1]	n/a	**198**	181
Canadian Mainline long-term adjustment account[7,10]	3	**111**	149
ANR post-employment and retirement benefits other than pension[11]	n/a	**42**	43
Operating and debt-service regulatory liabilities[2]	1	**23**	50
Pensions and other post-retirement benefits[3]	n/a	**6**	10
Other	n/a	**54**	99
		5,090	4,793
Less: Current portion included in Accounts payable and other (Note 18)		**284**	273
		4,806	4,520

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 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 $42 million (US$32 million) balance at December 31, 2023 is subject to resolution through future regulatory proceedings and, accordingly, a settlement period cannot be determined at this time.

15. GOODWILL

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

at December 31	2023		2022	
(millions)	Canadian dollars	U.S. dollars	Canadian dollars	U.S. dollars
Columbia Pipeline Group, Inc.	**9,708**	**7,351**	9,948	7,351
ANR	**2,570**	**1,946**	2,634	1,946
Great Lakes	**161**	**122**	165	122
North Baja	**63**	**48**	65	48
Tuscarora	**30**	**23**	31	23
	12,532	**9,490**	12,843	9,490

Changes in Goodwill were as follows:

(millions of Canadian $)	U.S. Natural Gas Pipelines
Balance at January 1, 2022	12,582
Great Lakes impairment charge	(571)
Foreign exchange rate changes	832
Balance at December 31, 2022	12,843
Foreign exchange rate changes	**(311)**
Balance at December 31, 2023	**12,532**

As part of the annual goodwill impairment assessment at December 31, 2023, the Company evaluated qualitative factors impacting the fair value of the underlying reporting units for all reporting units other than for the Tuscarora and North Baja 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.

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.

The Company evaluated qualitative factors impacting the fair value of the Columbia reporting unit from June 30, 2023 to December 31, 2023 and determined that it was more likely than not that the fair value remains higher than the carrying amount, including goodwill.

North Baja and Tuscarora

The Company elected to proceed directly to a quantitative annual impairment test at December 31, 2023 for the $3 million of goodwill related to the North Baja reporting unit due to the passage of time from the previous quantitative test at December 31, 2018. The Company also elected to proceed directly to a quantitative annual impairment test for the $30 million of goodwill related to the Tuscarora reporting unit due to the passage of time from the previous quantitative test at December 31, 2018, and subsequent to the Tuscarora Section 4 rate case settlement in 2023. It was determined that the fair values of North Baja and Tuscarora exceeded their carrying values, including goodwill, at December 31, 2023.

Great Lakes

In March 2022, Great Lakes reached a pre-filing settlement with its customers and filed an unopposed rate case settlement with FERC by which Great Lakes and the settling parties agreed to maintain existing recourse rates through October 31, 2025. Management performed a quantitative impairment test which evaluated a range of assumptions through a discounted cash flow model analysis using a risk-adjusted discount rate. It was determined that the estimated fair value of the Great Lakes reporting unit no longer exceeded its carrying value, including goodwill, and that an impairment charge was necessary. As a result, the Company recorded a pre-tax goodwill impairment charge of $571 million ($531 million after tax) for the year ended December 31, 2022 within the U.S. Natural Gas Pipelines segment that is included in Goodwill and asset impairment charges and other in the Company's Consolidated statement of income. The remaining goodwill balance related to Great Lakes was US$122 million at December 31, 2022. There is a risk that continued reductions in future cash flow forecasts and adverse changes in other key assumptions could result in a future impairment of the goodwill balance relating to Great Lakes. The majority of the Great Lakes goodwill impairment charge was allocated to non-deductible goodwill and the income tax recovery of $40 million was attributable to the portion of the goodwill that was deductible for income tax purposes. The estimated fair value measurements used in the Company's goodwill impairment analysis is classified as Level III of the fair value hierarchy. In the determination of the fair value utilized in the quantitative goodwill impairment test for each reporting unit, the Company used its projections of future cash flows and applied a risk-adjusted discount rate which involved significant estimates and judgments.

Asset Divestiture Program

TC Energy is progressing the asset divestiture program announced in 2022, which may involve the divestiture of reporting units, or portions thereof. These divestitures could include assets that have associated goodwill. To the extent that a sale transaction indicates a value lower than previously estimated, goodwill could be impaired. In the event of a partial sale of such assets, the anticipated proceeds will be considered in management’s assessment of fair value of the retained interest and any associated goodwill. The Company will continue to evaluate incremental capital rotation opportunities.

16. OTHER LONG-TERM ASSETS

at December 31 (millions of Canadian $)	2023	2022
Deferred income tax assets (Note 20)	**1,332**	1,070
Employee post-retirement benefits (Note 28)	**518**	563
Long-term contract assets (Note 6)	**457**	355
Capital projects in development	**237**	99
Fair value of derivative contracts (Note 29)	**155**	91
Keystone XL contractual recoveries (Note 7)	**34**	44
Keystone environmental provision recovery (Note 18)	**33**	240
Other	**252**	323
	3,018	2,785

17. NOTES PAYABLE

at December 31	2023		2022	
(millions of Canadian $, unless otherwise noted)	Outstanding	Weighted Average Interest Rate per Annum	Outstanding	Weighted Average Interest Rate per Annum
Canada[1]	—	—	5,971	4.9 %
Mexico (2023 – nil; 2022 – US$215)[2]	—	—	291	6.0 %
	—		6,262	

1 At December 31, 2023, Notes payable consisted of Canadian dollar-denominated notes of nil (2022 – $2,810 million) and U.S. dollar-denominated notes of nil (2022 – US$2,336 million).
2 In January 2023, the Company's Mexico subsidiary fully repaid the outstanding balance and terminated its MXN$ 5.0 billion demand senior unsecured revolving credit facility.

On August 25, 2023, TransCanada PipeLines Limited (TCPL) fully repaid and retired its 364-day $1.5 billion senior unsecured term loan bearing interest at a floating rate entered into on November 22, 2022.

At December 31, 2022, Notes payable reflects short-term borrowings in Canada by TCPL and in Mexico by a wholly-owned Mexican subsidiary.

At December 31, 2023, total committed revolving and demand credit facilities were $11.6 billion (2022 – $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)			2023		2022
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 2028	**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 2024	**US 2.5**	**US 2.5**	US 3.0
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2026	**US 2.5**	**US 2.5**	US 2.5
Demand senior unsecured revolving credit facilities[2]:					
TCPL / TCPL USA	Supports the issuance of letters of credit and provides additional liquidity; TCPL USA facility guaranteed by TCPL	Demand	**2.0**[3]	**1.0**	2.1[3]
Mexico subsidiary	For Mexico general corporate purposes, guaranteed by TCPL	Demand	—	—	MXN 5.0[3]

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, 2023, the Company was in compliance with all financial covenants.
3 Or the U.S. dollar equivalent.

For the year ended December 31, 2023, the cost to maintain the above facilities was $14 million (2022 – $14 million; 2021 – $17 million).

18. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	2023	2022
Trade payables	**4,832**	4,330
Fair value of derivative contracts (Note 29)	**1,143**	871
Regulatory liabilities (Note 14)	**284**	273
Keystone environmental provision	**122**	650
Contract liabilities (Note 6)	**69**	62
Class C Interests (Note 7)	**19**	37
Coastal GasLink contractual contribution (Notes 8, 12 and 33)	**—**	537
Other	**518**	389
	6,987	7,149

Keystone Environmental Provision

In December 2022, a pipeline incident occurred in Washington County, Kansas on the Keystone Pipeline System. At December 31, 2022, the Company accrued an environmental liability of $650 million, before expected insurance recoveries and not including potential fines and penalties which continue to be indeterminable. At June 30, 2023, the cost estimate for the incident was adjusted to $794 million based on a review of costs and commitments incurred and, at December 31, 2023, remains unchanged. Amounts paid for the environmental remediation liability were $676 million at December 31, 2023 (December 31, 2022 – nil). The remaining balance reflected in Accounts payable and other and Other long-term liabilities on the Company's Consolidated balance sheet was $122 million and $9 million, respectively at December 31, 2023 (December 31, 2022 – $650 million and nil, respectively).

The expected recovery of the remaining estimated environmental remediation costs recorded in Other current assets and Other long-term assets were $150 million and $33 million, respectively at December 31, 2023 (December 31, 2022 – $410 million and $240 million, respectively). An additional $36 million was accrued during the year, which is expected to be recoverable from TC Energy's wholly-owned captive insurance subsidiary. This amount was recorded as an expense in Interest income and other in the Consolidated statement of income. During the year, the Company received $575 million (2022 – nil) from its insurance policies related to the costs for environmental remediation. Restoration activities are ongoing and expected to continue into 2024.

19. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	2023	2022
Operating lease obligations (Note 11)	**401**	379
Fair value of derivative contracts (Note 29)	**106**	151
Employee post-retirement benefits (Note 28)	**97**	111
Asset retirement obligations	**64**	79
Long-term contract liabilities (Note 6)	**12**	32
Other	**335**	265
	1,015	1,017

20. INCOME TAXES

Geographic Components of Income before Income Taxes

year ended December 31 (millions of Canadian $)	2023	2022	2021
Canada	**(446)**	(2,154)	(292)
Foreign	**4,456**	3,528	2,458
Income before Income Taxes	**4,010**	1,374	2,166

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	2023	2022	2021
Current			
Canada	**73**	43	29
Foreign	**858**	372	276
	931	415	305
Deferred			
Canada	**(39)**	(467)	(327)
Foreign	**50**	641	142
	11	174	(185)
Income Tax Expense	**942**	589	120

Reconciliation of Income Tax Expense

year ended December 31 (millions of Canadian $)	2023	2022	2021
Income before income taxes	**4,010**	1,374	2,166
Federal and provincial statutory tax rate	**23.0 %**	23.0 %	23.0 %
Expected income tax expense	**922**	316	498
Income tax differential related to regulated operations	**(260)**	(174)	(139)
Foreign income tax rate differentials	**(174)**	(271)	(230)
Income from non-controlling interests and equity investments	**(56)**	(54)	(70)
Valuation allowance (release)	**197**	199	(8)
Non-taxable capital (gains) and losses	**196**	173	—
Mexico foreign exchange exposure	**132**	9	10
Impact of Mexico inflationary adjustments	**1**	24	32
Settlement of Mexico prior years' income tax assessments	**—**	196	—
U.S. minimum tax	**(14)**	96	—
Non-deductible goodwill impairment	**—**	91	—
Other	**(2)**	(16)	27
Income Tax Expense	**942**	589	120

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	2023	2022
Deferred Income Tax Assets		
Tax loss and credit carryforwards	**1,833**	1,519
Regulatory and other deferred amounts	**569**	571
Unrealized foreign exchange losses on long-term debt	**206**	333
Other	**73**	193
	2,681	2,616
Less: Valuation allowance	**730**	640
	1,951	1,976
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment	**6,816**	6,686
Equity investments	**1,115**	1,152
Taxes on future revenue requirement	**493**	397
Financial instruments	**160**	126
Other	**160**	193
	8,744	8,554
Net Deferred Income Tax Liabilities	**6,793**	6,578

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

at December 31 (millions of Canadian $)	2023	2022
Deferred Income Tax Assets		
Other long-term assets (Note 16)	**1,332**	1,070
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**8,125**	7,648
Net Deferred Income Tax Liabilities	**6,793**	6,578

At December 31, 2023, the Company has recognized the benefit of non-capital loss carryforwards of $5,593 million (2022 – $5,429 million) for federal and provincial purposes in Canada, which expire from 2030 to 2043. The Company has not yet recognized the benefit of capital loss carryforwards of $478 million (2022 – $251 million) for federal and provincial purposes in Canada which have no expiry date. The Company also has Ontario corporate minimum tax (CMT) credits of $140 million (2022 – $126 million), which expire from 2026 to 2043. As of December 31, 2023, the Company has not recognized the benefit of CMT credits of $22 million (2022 – $22 million).

At December 31, 2023, the Company has recognized the benefit of net operating loss carryforwards of US$47 million (2022 – US$69 million) in Mexico, which expire from 2024 to 2033.

TC Energy recorded an income tax valuation allowance of $730 million and $640 million against the deferred income tax asset balances at December 31, 2023 and 2022, respectively. The increase in the valuation allowance is primarily a result of the foreign exchange movement on unrecognized capital losses and the unrealized non-taxable capital losses on the Coastal GasLink equity investment. At December 31, 2023, the Company recorded a total of $358 million (2022 – $173 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, 2023. 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. As at December 31, 2023, 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.

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, 2023 by approximately $1,629 million (2022 – $1,216 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $836 million, net of refunds, were made in 2023 (2022 – payments, net of refunds, of $894 million; 2021 – payments, net of refunds, of $371 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 $)	**2023**	**2022**	**2021**
Unrecognized tax benefit at beginning of year	**91**	80	52
Gross increases – tax positions in prior years	**9**	6	5
Gross decreases – tax positions in prior years	**(1)**	—	(1)
Gross increases – tax positions in current year	**16**	7	26
Lapse of statutes of limitations	**(30)**	(2)	(2)
Unrecognized Tax Benefit at End of Year	**85**	91	80

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, 2023 reflects $3 million interest expense (2022 – $6 million; 2021 – $1 million). At December 31, 2023, the Company had accrued $21 million in interest expense (2022 – $18 million; 2021 – $12 million). The Company incurred no penalties associated with income tax uncertainties related to income tax expense for the years ended December 31, 2023, 2022 and 2021 and no penalties were accrued as at December 31, 2023, 2022 and 2021.

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 2015. Substantially all material U.S. federal, state and local income tax matters have been concluded for years through 2015. Substantially all material Mexico income tax matters have been concluded for years through 2017.

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.

21. LONG-TERM DEBT

at December 31		2023		2022	
(millions of Canadian $, unless otherwise noted)	Maturity Dates	Outstanding	Interest Rate[1]	Outstanding	Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Medium Term Notes					
Canadian	2024 to 2052	**15,466**	**4.6 %**	13,966	4.5 %
Senior Unsecured Notes					
U.S. (2023 – US$16,167; 2022 – US$15,542)	2024 to 2049	**21,349**	**5.0 %**	21,032	4.9 %
		36,815		34,998	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian	2024	**100**	**9.9 %**	100	9.9 %
U.S. (2023 – nil; 2022 – US$200)		**—**	**—**	271	7.9 %
Medium Term Notes					
Canadian	2025 to 2030	**504**	**7.4 %**	504	7.4 %
U.S. (2023 and 2022 – US$33)	2026	**43**	**7.5 %**	44	7.5 %
		647		919	
COLUMBIA PIPELINE GROUP, INC.					
Senior Unsecured Notes[2]					
U.S. (2023 – nil; 2022 – US$1,500)		**—**	**—**	2,030	4.9 %
COLUMBIA PIPELINES OPERATING COMPANY LLC					
Senior Unsecured Notes[2]					
U.S. (2023 – US$6,100; 2022 – nil)	2025 to 2063	**8,055**	**6.1 %**	—	—
COLUMBIA PIPELINES HOLDING COMPANY LLC					
Senior Unsecured Notes[2]					
U.S. (2023 – US$1,000; 2022 – nil)	2026 to 2028	**1,320**	**6.2 %**	—	—
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2023 and 2022 – US$1,172)	2024 to 2037	**1,548**	**4.1 %**	1,587	4.1 %
TC PIPELINES, LP					
Senior Unsecured Notes					
U.S. (2023 and 2022 – US$850)	2025 to 2027	**1,122**	**4.2 %**	1,150	4.2 %

at December 31		2023		2022	
(millions of Canadian $, unless otherwise noted)	Maturity Dates	Outstanding	Interest Rate[1]	Outstanding	Interest Rate[1]
GAS TRANSMISSION NORTHWEST LLC					
Senior Unsecured Notes					
U.S. (2023 – US$375; 2022 – US$325)	2030 to 2035	**495**	**4.4 %**	440	4.3 %
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Unsecured Notes					
U.S. (2023 and 2022 – US$250)	2030 to 2031	**330**	**2.8 %**	338	2.8 %
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. (2023 – US$125; 2022 – US$146)	2028 to 2030	**165**	**7.6 %**	198	7.6 %
TUSCARORA GAS TRANSMISSION COMPANY					
Unsecured Term Loan					
U.S. (2023 – nil; 2022 – US$34)		**—**	**—**	46	6.5 %
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.					
Senior Unsecured Term Loan					
U.S. (2023 – US$1,800; 2022 – nil)	2028	**2,377**	**7.7 %**	—	—
Senior Unsecured Revolving Credit Facility					
U.S. (2023 – US$185; 2022 – nil)	2028	**244**	**7.7 %**	—	—
		2,621		—	
		53,118		41,706	
Current portion of long-term debt		**(2,938)**		(1,898)	
Unamortized debt discount and issue costs		**(312)**		(239)	
Fair value adjustments[3]		**108**		76	
		49,976		39,645	

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 8, 2023, US$ 1.5 billion senior unsecured notes were assigned from Columbia Pipelines Group, Inc. to Columbia Pipelines Operating Company LLC in advance of the October 4, 2023 sale of a 4 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf. Preceding this sale, US$5.6 billion of senior unsecured notes were issued. Refer to Note 24, Non-controlling interests, for additional information.

3 The fair value adjustments include $119 million (2022 – $ 140 million) related to the acquisition of Columbia Pipeline Group, Inc. These adjustments also include a decrease of $ 11 million (2022 – $64 million) related to hedged interest rate risk. Refer to Note 29, Risk management and financial instruments, for additional information.

Principal Repayments

At December 31, 2023, principal repayments for the next five years on the Company's long-term debt are approximately as follows:

(millions of Canadian $)	2024	2025	2026	2027	2028
Principal repayments on long-term debt	2,938	2,779	5,287	3,096	6,232

Long-Term Debt Issued

The Company issued long-term debt over the three years ended December 31, 2023 as follows:

(millions of Canadian $, unless otherwise noted)					
Company	**Issue Date**	**Type**	**Maturity Date**	**Amount**	**Interest Rate**
TRANSCANADA PIPELINES LIMITED					
	May 2023	Senior Unsecured Term Loan[1]	May 2026	US 1,024	Floating
	March 2023	Senior Unsecured Notes	March 2026[2]	US 850	6.20 %
	March 2023	Senior Unsecured Notes	March 2026[2]	US 400	Floating
	March 2023	Medium Term Notes	July 2030	1,250	5.28 %
	March 2023	Medium Term Notes	March 2026[2]	600	5.42 %
	March 2023	Medium Term Notes	March 2026[2]	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 %
	October 2021	Senior Unsecured Notes	October 2024	US 1,250	1.00 %
	October 2021	Senior Unsecured Notes	October 2031	US 1,000	2.50 %
	June 2021	Medium Term Notes	June 2024	750	Floating
	June 2021	Medium Term Notes	June 2031	500	2.97 %
	June 2021	Medium Term Notes	September 2047	250	4.33 % [3]
COLUMBIA PIPELINES OPERATING COMPANY LLC					
	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					
	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 %
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
	October 2021	Senior Unsecured Notes	October 2031	US 125	2.68 %

(millions of Canadian $, unless otherwise noted)					
Company	**Issue Date**	**Type**	**Maturity Date**	**Amount**	**Interest Rate**
TUSCARORA GAS TRANSMISSION COMPANY					
	August 2021	Unsecured Term Loan	August 2024	US 13	Floating
KEYSTONE XL SUBSIDIARIES[4]					
	Various	Project-Level Credit Facility	June 2021	US 849	Floating
COLUMBIA PIPELINE GROUP, INC.[5]					
	January 2021	Unsecured Term Loan	June 2022	US 4,040	Floating

1 This loan was fully repaid and retired in September 2023. Related unamortized debt issue costs of $ 3 million were included in Interest expense in the Consolidated statement of income.

2 Callable at par in March 2024 or at any time thereafter.

3 Reflects coupon rate on re-opening of a pre-existing Medium Term Notes (MTN) issue. The MTNs were issued at a premium to par, resulting in a re-issuance yield of 4.19 per cent.

4 In January 2021, the Company established a US$ 4.1 billion project-level credit facility to support the construction of the Keystone XL pipeline, which was fully guaranteed by the Government of Alberta and non-recourse to TC Energy. The availability of this credit facility was subsequently reduced to US$1.6 billion and all amounts outstanding were fully repaid by the Government of Alberta in June 2021. Refer to Note 7, Keystone XL, for additional information.

5 In December 2020, Columbia entered into a US$ 4.2 billion Unsecured Term Loan agreement. In January 2021, US$ 4.0 billion was drawn on the Unsecured Term Loan and the total availability under the loan agreement was reduced accordingly. The loan was fully repaid and retired in December 2021.

On January 9, 2024, Columbia Pipelines Holding Company LLC issued US$500 million senior unsecured notes due January 2034, bearing interest at a fixed rate of 5.68 per cent.

Long-Term Debt Retired/Repaid

The Company retired/repaid long-term debt over the three years ended December 31, 2023 as follows:

(millions of Canadian $, unless otherwise noted)				
Company	**Retirement/Repayment Date**	**Type**	**Amount**	**Interest Rate**
TRANSCANADA PIPELINES LIMITED				
	October 2023	Senior Unsecured Notes	US 625	3.75 %
	September 2023	Senior Unsecured Notes[1]	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 %
	November 2021	Medium Term Notes	500	3.65 %
	January 2021	Debentures	US 400	9.88 %
TUSCARORA GAS TRANSMISSION COMPANY				
	November 2023	Unsecured Term Loan	US 32	Floating
NOVA GAS TRANSMISSION LTD.				
	April 2023	Debentures	US 200	7.88 %
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.				
	Various	Senior Unsecured Revolving Credit Facility	US 315	Floating
COLUMBIA PIPELINE GROUP, INC.				
	December 2021	Unsecured Term Loan[2]	US 4,040	Floating
NORTH BAJA PIPELINE, LLC				
	December 2021	Unsecured Term Loan	US 50	Floating
TC PIPELINES, LP				
	November 2021	Unsecured Term Loan	US 450	Floating
	March 2021	Senior Unsecured Notes	US 350	4.65 %
ANR PIPELINE COMPANY				
	November 2021	Senior Unsecured Notes	US 300	9.63 %
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP				
	November 2021	Senior Unsecured Notes	US 10	9.09 %
PORTLAND NATURAL GAS TRANSMISSION SYSTEM				
	October 2021	Unsecured Loan Facility	US 93	Floating
KEYSTONE XL SUBSIDIARIES[3]				
	June 2021	Project-Level Credit Facility	US 849	Floating

1 In May 2023, the Company entered into a US$ 1,024 million senior unsecured term loan and the full amount was drawn. The loan was fully repaid and retired in September 2023. Related unamortized debt issue costs of $3 million were included in Interest expense in the Consolidated statement of income.

2 In December 2020, Columbia entered into a US$ 4.2 billion Unsecured Term Loan agreement. In January 2021, US$ 4.0 billion was drawn on the Unsecured Term Loan and the total availability under the loan agreement was reduced accordingly. The loan was fully repaid and retired in December 2021. Related unamortized debt issue costs of $5 million were included in Interest expense in the Consolidated statement of income for the year ended December 31, 2021.

3 In June 2021, in accordance with the terms of the guarantee, the Government of Alberta repaid the US$ 849 million outstanding balance under the Keystone XL project-level credit facility bearing interest at a floating rate, subsequent to which it was terminated, resulting in no cash impact to TC Energy. Refer to Note 7, Keystone XL, for additional information.

In March 2021, the Company's subsidiary, TC PipeLines, LP, terminated its US$500 million Unsecured Loan Facility bearing interest at a floating rate on which no amount was outstanding.

Interest Expense

year ended December 31 (millions of Canadian $)	2023	2022	2021
Interest on long-term debt	**2,562**	1,883	1,841
Interest on junior subordinated notes	**617**	543	453
Interest on short-term debt	**165**	153	10
Capitalized interest	**(187)**	(27)	(22)
Amortization and other financial charges[1]	**106**	36	78
	3,263	2,588	2,360

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 $2,931 million in 2023 (2022 – $2,478 million; 2021 – $2,299 million) on long-term debt, junior subordinated notes and short-term debt, net of interest capitalized.

22. JUNIOR SUBORDINATED NOTES

at December 31		2023		2022	
(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	**1,320**	**6.5 %**	1,353	6.2 %
US$750 issued 2015 at 5.88%[3,4]	2075	**990**	**7.8 %**	1,015	7.4 %
US$1,200 issued 2016 at 6.13%[3,4]	2076	**1,585**	**8.3 %**	1,624	8.0 %
US$1,500 issued 2017 at 5.55%[3,4]	2077	**1,981**	**7.5 %**	2,030	7.1 %
$1,500 issued 2017 at 4.90%[3,4]	2077	**1,500**	**7.0 %**	1,500	6.8 %
US$1,100 issued 2019 at 5.75%[3,4]	2079	**1,453**	**8.0 %**	1,488	7.6 %
$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	**1,056**	**7.1 %**	1,083	7.2 %
		10,385		10,593	
Unamortized debt discount and issue costs		**(98)**		(98)	
		10,287		10,495	

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.

In March 2021, the Trust issued $500 million of Trust Notes – Series 2021-A to investors with a fixed interest rate of 4.20 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 $500 million of junior subordinated notes of TCPL at an initial fixed rate of 4.45 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 2031 until March 2051 to the then Five-Year Government of Canada Yield, as defined in the document governing the subordinated notes, plus 3.316 per cent per annum; from March 2051 until March 2081, the interest rate will reset every five years to the then Five-Year Government of Canada Yield plus 4.066 per cent per annum. The junior subordinated notes are callable at TCPL's option at any time from December 4, 2030 to March 4, 2031 and on each interest payment and reset date thereafter at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

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.

23. FOREIGN EXCHANGE (GAINS) LOSSES, NET

year ended December 31			
(millions of Canadian $)	**2023**	**2022**	**2021**
Derivative instruments held for trading (Note 29)	**(401)**	151	(37)
Other	**81**	34	27
	(320)	185	(10)

24. NON-CONTROLLING INTERESTS

Disposition of Equity Interest

Columbia Gas and Columbia Gulf

On October 4, 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.

Preceding the close of the equity sale, on August 8, 2023, Columbia Pipelines Operating Company LLC and Columbia Pipelines Holding Company LLC issued US$4.6 billion and US$1.0 billion of long-term, senior unsecured debt, respectively, with all proceeds paid to TC Energy. The net proceeds from the offerings and equity sale were used to repay existing intercompany and third-party debt. Refer to Note 21, Long-term debt, for additional information.

Acquisitions

Texas Wind Farms

On March 15, 2023 and June 14, 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.

TC PipeLines, LP

On March 3, 2021, the Company acquired all the outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy or its affiliates in exchange for TC Energy common shares. Under this transaction, TC PipeLines, LP common unitholders received 0.70 TC Energy common shares for each issued and outstanding publicly-held TC PipeLines, LP common unit representing, in aggregate, 37,955,093 TC Energy common shares. As a result, TC PipeLines, LP became an indirect, wholly-owned subsidiary of TC Energy.

As the Company controlled TC PipeLines, LP, this acquisition was accounted for as an equity transaction with the following impact reflected on the Consolidated balance sheet:

(millions of Canadian $)	March 3, 2021
Common shares	**2,063**
Additional paid-in-capital	**(398)**
Accumulated other comprehensive income (loss)	**353**
Non-controlling interests	**(1,563)**
Deferred income tax liabilities	**(443)**
Other	**(12)**

Non-controlling interests

The Company's Net income (loss) attributable to non-controlling interests included in the Consolidated statement of income and Non-controlling interests included on the Consolidated balance sheet were as follows:

		Income (Loss) Attributable to Non-Controlling Interests			Non-Controlling Interests	
		year ended December 31			at December 31	
(millions of Canadian $)	Non-Controlling Interests Ownership at December 31, 2023	2023	2022	2021	2023	2022
Columbia Gas and Columbia Gulf	40.0 %	**143**	—	—	**9,167**	—
Portland Natural Gas Transmission System	38.3 %	**41**	37	30	**106**	126
Texas Wind Farms	100% [1]	**(38)**	—	—	**182**	—
TC PipeLines, LP	nil [2]	**—**	—	60	**—**	—
Redeemable non-controlling interest (Note 7)	nil	**—**	—	1	**—**	—
		146	37	91	**9,455**	126

1 Non-controlling interests in the Texas Wind Farms comprises Class A Membership Interests.

2 Prior to the March 3, 2021 acquisition, the non-controlling interest in TC PipeLines, LP was 74.5 per cent.

25. COMMON SHARES

	Number of Shares (thousands)	Amount (millions of Canadian $)
Outstanding at January 1, 2021	940,064	24,488
Acquisition of TC PipeLines, LP, net of transaction costs (Note 24)	37,955	2,063
Exercise of options	2,797	165
Outstanding at December 31, 2021	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**

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 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.

Acquisition of TC PipeLines, LP

On March 3, 2021, TC Energy issued 37,955,093 common shares to acquire all the outstanding publicly-held common units of TC PipeLines, LP. Refer to Note 24, Non-controlling interests, for additional information.

Basic and Diluted Net Income (Loss) per Common Share

Net income (loss) per common share is calculated by dividing Net income (loss) attributable to common shares 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 (millions)	**2023**	**2022**	**2021**
Basic	**1,030**	995	973
Diluted	**1,030**	996	974

Stock Options

	Number of Options (thousands)	Weighted Average Exercise Prices	Weighted Average Remaining Contractual Life (years)
Options outstanding at January 1, 2023	**6,109**	**$63.86**	
Options granted	**1,933**	**$56.66**	
Options exercised	**(62)**	**$48.44**	
Options forfeited/expired	**(544)**	**$60.60**	
Options Outstanding at December 31, 2023	**7,436**	**$62.36**	**4.1**
Options Exercisable at December 31, 2023	**4,375**	**$64.47**	**3.0**

At December 31, 2023, an additional2,267,871 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.

The Company used a binomial model for determining the fair value of options granted and applied the following weighted average assumptions:

year ended December 31	2023	2022	2021
Weighted average fair value	**$7.88**	$8.24	$7.39
Expected life (years)[1]	**5.1**	5.4	5.4
Interest rate	**2.9 %**	1.6 %	0.5 %
Volatility[2]	**24 %**	22 %	25 %
Dividend yield	**6.3 %**	5.5 %	6.0 %

1 Expected life is based on historical exercise activity.
2 Volatility is derived based on the average of both the historical and implied volatility of the Company's common shares.

The amount expensed for stock options, with a corresponding increase in Additional paid-in capital, was $9 million in 2023 (2022 – $10 million; 2021 – $12 million). At December 31, 2023, unrecognized compensation costs related to non-vested stock options were $12 million. The cost is expected to be fully recognized over a weighted average period of two years.

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian $, unless otherwise noted)	2023	2022	2021
Total intrinsic value of options exercised	**—**	33	28
Total fair value of options that have vested	**76**	89	110
Total options vested	**1.5 million**	1.6 million	1.9 million

As at December 31, 2023, the aggregate intrinsic values of the total options exercisable and the total options outstanding werenil.

Shareholder Rights Plan

TC Energy's Shareholder Rights Plan is designed to provide the Board of Directors (Board) 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.

26. PREFERRED SHARES

at December 31, 2023	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] 2023	2022	2021
							(millions of Canadian $)		
Cumulative First Preferred Shares									
Series 1	14,577	3.48 %	$0.86975	$25.00	December 31, 2024	Series 2	**360**	360	360
Series 2	7,423	Floating[4]	Floating	$25.00	December 31, 2024	Series 1	**179**	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[4]	Floating	$25.00	June 30, 2025	Series 3	**97**	97	97
Series 5	12,071	1.95 %[5]	$0.48725	$25.00	January 30, 2026	Series 6	**294**	294	294
Series 6	1,929	Floating[4]	Floating	$25.00	January 30, 2026	Series 5	**48**	48	48
Series 7	24,000	3.90 %	$0.97575	$25.00	April 30, 2024	Series 8	**589**	589	589
Series 9	18,000	3.76 %	$0.9405	$25.00	October 30, 2024	Series 10	**442**	442	442
Series 11	10,000	3.35 %	$0.83775	$25.00	November 28, 2025	Series 12	**244**	244	244
Series 15	—	—	—	—	—	—	**—**	—	988
							2,499	2,499	3,487

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 floating quarterly dividend rate for the Series 2 preferred shares is 6.96 per cent for the period starting December 29, 2023 to, but excluding, March 28, 2024. The floating quarterly dividend rate for the Series 4 preferred shares is 6.32 per cent for the period starting December 29, 2023 to, but excluding, March 28, 2024. The floating quarterly dividend rate for the Series 6 preferred shares is 6.69 per cent for the period starting October 30, 2023 to, but excluding, January 30, 2024. These rates will reset each quarter going forward.

5 The fixed rate dividend for Series 5 preferred shares decreased from 2.26 per cent to 1.95 per cent on January 30, 2021 and is due to reset on every fifth anniversary thereafter.

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 and Series 6 preferred shares. The holders of Series 2, Series 4 and Series 6 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 and Series 6 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 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.

In May 2021, TC Energy redeemed all 20,000,000 issued and outstanding Series 13 preferred shares at a redemption price of $25.00 per share and paid the final quarterly dividend of $0.34375 per Series 13 preferred share for the period up to but excluding May 31, 2021. The Company used the proceeds from the March 2021 issuance of $500 million of junior subordinated notes through the Trust to finance this preferred share redemption.

In February 2021, 818,876 Series 5 preferred shares were converted, on a one-for-one basis, into Series 6 preferred shares and 175,208 Series 6 preferred shares were converted, on a one-for-one basis, into Series 5 preferred shares.

27. 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, 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

year ended December 31, 2021 (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	(100)	(8)	(108)
Change in fair value of net investment hedges	(3)	1	(2)
Change in fair value of cash flow hedges	(13)	3	(10)
Reclassification to net income of (gains) losses on cash flow hedges	68	(13)	55
Unrealized actuarial gains (losses) on pension and other post-retirement benefit plans	208	(50)	158
Reclassification to net income of actuarial (gains) losses on pension and other post-retirement benefit plans	20	(6)	14
Other comprehensive income (loss) on equity investments	714	(179)	535
Other Comprehensive Income (Loss)	894	(252)	642

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, 2021	(1,273)	(143)	(285)	(738)	(2,439)
Other comprehensive income (loss) before reclassifications[1]	(98)	(11)	158	506	555
Amounts reclassified from AOCI	—	55	14	28	97
Net current period other comprehensive income (loss)	(98)	44	172	534	652
Acquisition of TC PipeLines, LP[2]	362	(13)	—	4	353
AOCI balance at December 31, 2021	(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[3]	**—**	**74**	**—**	**(16)**	**58**
Net current period other comprehensive income (loss)	**(231)**	**74**	**(11)**	**(211)**	**(379)**
Impact of non-controlling interest[4]	**(527)**	**—**	**—**	**—**	**(527)**
AOCI balance at December 31, 2023	**(317)**	**(35)**	**(55)**	**456**	**49**

1 Other comprehensive income(loss) before reclassifications on currency translation adjustments, cash flow hedges and equity investments are net of non-controlling interest loss of $366 million (2022 – gains of $8 million; 2021 – losses of $ 12 million), nil (2022 – nil; 2021 – gains of $ 1 million), and nil (2022 – nil; 2021 – gains of $ 1 million), respectively.

2 Represents the AOCI attributable to non-controlling interests of TC PipeLines, LP which was reclassified to AOCI on the Consolidated balance sheet upon completion of the acquisition of all the outstanding publicly-held common units of TC PipeLines, LP on March 3, 2021. Refer to Note 24, Non-controlling interests, for additional information.

3 Losses 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 $ 4 million ($3 million, net of tax) at December 31, 2023. 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 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 24, Non-controlling interests, 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			
(millions of Canadian $)	2023	2022	2021	Affected Line Item in the Consolidated Statement of Income[1]
Cash flow hedges				
Commodities	**(85)**	(47)	(22)	Revenues (Power and Energy Solutions)
Interest rate	**(12)**	(16)	(46)	Interest expense
	(97)	(63)	(68)	Total before tax
	23	21	13	Income tax (expense) recovery
	(74)	(42)	(55)	Net of tax
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial gains (losses)	**—**	(11)	(22)	Plant operating costs and other[2]
Settlement gain (loss)	**—**	2	2	Plant operating costs and other[2]
	—	(9)	(20)	Total before tax
	—	3	6	Income tax (expense) recovery
	—	(6)	(14)	Net of tax
Equity investments				
Equity income (loss)	**22**	4	(37)	Income (loss) from equity investments
	(6)	(1)	9	Income tax (expense) recovery
	16	3	(28)	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 28, Employee post-retirement benefits, for additional information.

28. 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, and up until the Canadian DB Plan was closed to new entrants on January 1, 2024, benefits provided for these new members are 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. In 2023, TC Energy announced a plan amendment to the Canadian OPEB Plan. This plan will be closed for any eligible active employees that do 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, 2023 (2022 – nine years; 2021 – 10 years).

The Company also provides its employees with savings plans in Canada and 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, 2023 (2022 – 12 years and 2021 – 11 years). In 2023, the Company expensed $64 million (2022 – $64 million and 2021 – $58 million) for the savings and DC Plans.

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

year ended December 31			
(millions of Canadian $)	**2023**	**2022**	**2021**
DB Plans	**28**	78	105
Other post-retirement benefit plans	**9**	8	8
Savings and DC Plans	**64**	64	58
	101	150	171

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, 2023 was $244 million (2022 – $322 million; 2021 – $322 million).

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2023 and the next required valuation is at January 1, 2024.

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.

In mid-2021, the Company offered a one-time Voluntary Retirement Program (VRP) to eligible employees. Participants in the program retired by December 31, 2021 and received a transition payment along with existing retirement benefits. In 2021, the Company expensed $81 million mainly related to VRP transition payments which were included in Plant operating costs and other. In addition, $18 million was recorded in Revenues related to costs that are recoverable through regulatory and tolling structures on a flow-through basis.

As a result of employee participation in the VRP in 2021, a settlement and curtailment occurred for the U.S. DB Plan and a curtailment occurred in the U.S. OPEB Plan. The impact of these amounts was determined using actuarial assumptions consistent with those employed at December 31, 2021. The settlement gain decreased the U.S. DB Plan's unrealized actuarial gain by $2 million which was included in OCI, while the curtailment gain decreased the U.S. DB Plan's benefit obligation by $5 million, both of which were recorded in net benefit cost in 2021. The curtailment loss decreased the OPEB Plan's unrealized actuarial gain by $3 million which was included in OCI and increased the OPEB Plan obligation by $3 million, resulting in no adjustment to net benefit cost in 2021.

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

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	2023	2022	2023	2022
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**3,081**	4,027	**310**	419
Service cost	**93**	145	**3**	5
Interest cost	**158**	125	**16**	13
Employee contributions	**7**	6	**2**	2
Benefits paid	**(185)**	(324)	**(44)**	(24)
Actuarial (gain) loss	**219**	(949)	**2**	(120)
Foreign exchange rate changes	**(17)**	51	**(4)**	15
Benefit obligation – end of year	**3,356**	3,081	**285**	310
Change in Plan Assets				
Plan assets at fair value – beginning of year	**3,481**	4,145	**354**	431
Actual return on plan assets	**385**	(483)	**24**	(89)
Employer contributions[2]	**28**	78	**9**	8
Employee contributions	**7**	6	**2**	2
Benefits paid	**(185)**	(324)	**(23)**	(24)
Foreign exchange rate changes	**(19)**	59	**(8)**	26
Plan assets at fair value – end of year	**3,697**	3,481	**358**	354
Funded Status – Plan Surplus	**341**	400	**73**	44

1 The benefit obligation for the Company's pension benefit plans represents the projected benefit obligation. The benefit obligation for the Company's other post-retirement benefit plans represents the accumulated post-retirement benefit obligation.

2 The Company reduced letters of credit by $ 78 million in the Canadian DB Plan (2022 – nil) for funding purposes.

The actuarial loss realized on the defined benefit plan obligation is primarily attributable to a decrease in the weighted average discount rate from 5.15 per cent in 2022 to 4.75 per cent in 2023.

The actuarial loss realized on the OPEB Plan obligation is primarily due to a decrease in the weighted average discount rate from 5.45 per cent in 2022 to 5.10 per cent in 2023.

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 $)	2023	2022	2023	2022
Other long-term assets (Note 16)	**341**	400	**177**	163
Accounts payable and other	**—**	—	**(7)**	(8)
Other long-term liabilities (Note 19)	**—**	—	**(97)**	(111)
	341	400	**73**	44

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 $)	2023	2022	2023	2022
Projected benefit obligation[1]	**—**	—	**(104)**	(119)
Plan assets at fair value	**—**	—	**—**	—
Funded Status – Plan Deficit	**—**	—	**(104)**	(119)

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 $)	2023	2022
Accumulated benefit obligation	**(3,090)**	(2,880)
Plan assets at fair value	**3,697**	3,481
Funded Status – Plan Surplus	**607**	601

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, 2023 and December 31, 2022.

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
	2023	2022	2023
Fixed income securities	**41 %**	38 %	**30% to 50%**
Equity securities	**44 %**	44 %	**30% to 55%**
Other investments	**15 %**	18 %	**10% to 25%**
	100 %	100 %	

Fixed income and equity securities include the Company's debt and common shares as follows:

at December 31			Percentage of Plan Assets	
(millions of Canadian $)	2023	2022	2023	2022
Fixed income securities	**7**	7	**0.2 %**	0.2 %
Equity securities	**2**	3	**0.1 %**	0.1 %

Pension plan assets are managed on a going concern basis, subject to legislative restrictions, and are diversified across asset classes to maximize returns at an acceptable level of risk. Asset mix strategies consider plan demographics and may include traditional equity and debt securities as well as alternative assets such as infrastructure, private equity, real estate and derivatives to diversify risk. Derivatives are not used for speculative purposes and may be used to hedge certain liabilities.

All investments are measured at fair value using market prices. Where the fair value cannot be readily determined by reference to generally available price quotations, the fair value is determined by considering the discounted cash flows on a risk-adjusted basis and by comparison to similar assets which are publicly traded. In Level I, the fair value of assets is determined by reference to quoted prices in active markets for identical assets that the Company has the ability to access at the measurement date. In Level II, the fair value of assets is determined using valuation techniques such as option pricing models and extrapolation using significant inputs which are observable directly or indirectly. In Level III, the fair value of assets is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement.

The following table presents plan assets for DB Plans and OPEB Plans measured at fair value, which have been categorized into the three categories based on a fair value hierarchy. Refer to Note 29, 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 $)	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022
Asset Category										
Cash and Cash Equivalents	**68**	55	**1**	1	**—**	—	**69**	56	**2**	1
Equity Securities:										
Canadian	**121**	117	**—**	—	**—**	—	**121**	117	**3**	3
U.S.	**965**	897	**—**	—	**—**	—	**965**	897	**24**	24
International	**167**	172	**187**	172	**—**	—	**354**	344	**9**	9
Global	**—**	—	**74**	75	**—**	—	**74**	75	**2**	2
Emerging	**54**	50	**140**	127	**—**	—	**194**	177	**5**	5
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**266**	221	**—**	—	**266**	221	**7**	6
Provincial	**—**	—	**314**	249	**—**	—	**314**	249	**8**	6
Municipal	**—**	—	**16**	12	**—**	—	**16**	12	**—**	—
Corporate	**—**	—	**143**	108	**—**	—	**143**	108	**4**	3
U.S. Bonds:										
Federal	**185**	177	**240**	158	**—**	—	**425**	335	**10**	9
Municipal	**—**	—	**1**	1	**—**	—	**1**	1	**—**	—
Corporate	**312**	345	**74**	94	**—**	—	**386**	439	**10**	11
International:										
Government	**4**	5	**11**	6	**—**	—	**15**	11	**—**	—
Corporate	**—**	—	**83**	58	**—**	—	**83**	58	**2**	1
Mortgage backed	**43**	36	**17**	1	**—**	—	**60**	37	**1**	1
Net forward contracts	**—**	—	**(131)**	(78)	**—**	—	**(131)**	(78)	**(4)**	(2)
Other Investments:										
Real estate	**—**	—	**—**	—	**283**	336	**283**	336	**7**	9
Infrastructure	**—**	—	**—**	—	**269**	296	**269**	296	**7**	8
Private equity funds	**—**	—	**—**	—	**10**	—	**10**	—	**—**	—
Funds held on deposit	**138**	144	**—**	—	**—**	—	**138**	144	**3**	4
	2,057	1,998	**1,436**	1,205	**562**	632	**4,055**	3,835	**100**	100

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

(millions of Canadian $, pre-tax)	
Balance at December 31, 2021	565
Purchases and sales	52
Realized and unrealized gains (losses)	15
Balance at December 31, 2022	632
Purchases and sales	**(76)**
Realized and unrealized gains (losses)	**6**
Balance at December 31, 2023	**562**

In 2024, the Company's expects to make funding contributions of $6 million for the other post-retirement benefit plans, approximately $70 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 2024.

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

at December 31 (millions of Canadian $)	Pension Benefits	Other Post-Retirement Benefits
2024	204	23
2025	207	23
2026	211	23
2027	214	22
2028	216	22
2029 to 2033	1,127	104

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, 2023. 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	
	2023	2022	2023	2022
Discount rate	**4.75 %**	5.15 %	**5.10 %**	5.45 %
Rate of compensation increase	**3.20 %**	3.30 %	**—**	—

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		
	2023	2022	2021	2023	2022	2021
Discount rate	**5.15 %**	3.05 %	2.70 %	**5.45 %**	3.10 %	2.80 %
Expected long-term rate of return on plan assets	**6.45 %**	6.10 %	6.15 %	**4.50 %**	3.25 %	3.00 %
Rate of compensation increase	**3.25 %**	3.00 %	2.60 %	**—**	—	—

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 5.95 per cent weighted-average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2024 measurement purposes. The rate was assumed to decrease gradually to 4.80 per cent by 2030 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 $)	2023	2022	2021	2023	2022	2021
Service cost[1]	**93**	145	171	**3**	5	6
Other components of net benefit cost[1]						
Interest cost	**158**	125	119	**16**	13	12
Expected return on plan assets	**(234)**	(239)	(234)	**(16)**	(14)	(13)
Amortization of actuarial loss	**—**	10	23	**—**	1	2
Amortization of regulatory asset	**—**	12	27	**—**	1	2
Curtailment gain	**—**	—	(5)	**—**	—	—
Settlement gain – AOCI	**—**	(2)	(2)	**—**	—	—
	(76)	(94)	(72)	**—**	1	3
Net Benefit Cost Recognized	**17**	51	99	**3**	6	9

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	2023		2022		2021	
(millions of Canadian $)	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Net loss	**71**	**6**	38	24	147	5

Pre-tax amounts recognized in OCI were as follows:

year ended December 31	2023		2022		2021	
(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	**—**	**—**	(10)	(1)	(23)	(2)
Curtailment	**—**	**—**	—	—	—	3
Settlement	**—**	**—**	2	—	2	—
Funded status adjustment	**33**	**(18)**	(101)	20	(190)	(18)
	33	**(18)**	(109)	19	(211)	(17)

29. 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 liquids marketing business, TC Energy enters into pipeline and storage terminal capacity contracts as well as crude oil purchase and sale agreements. The Company fixes a portion of the exposure on these contracts by entering into financial instruments to manage variable price fluctuations that arise from physical liquids transactions
- 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, crude oil 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.

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 the Company's asset portfolio against a range of future pricing and supply and demand outcomes as part of the Company's strategic planning process. TC Energy's exposure to climate change-related transition risks and resulting policy changes is managed through the Company's 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. As the Company's U.S. dollar-denominated operations continue to grow, this exposure increases. 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 from equity investments and Income tax expense. 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	**2023**		**2022**	
(millions of Canadian $, unless otherwise noted)	**Fair Value[1,2]**	**Notional Amount**	**Fair Value[1,2]**	**Notional Amount**
U.S. dollar foreign exchange options (maturing 2024)	**8**	**US 1,000**	(22)	US 3,600
U.S. dollar cross-currency interest rate swaps (maturing 2024 to 2025)[3]	**2**	**US 200**	(5)	US 300
	10	**US 1,200**	(27)	US 3,900

1 Fair value equals carrying value.
2 No amounts have been excluded from the assessment of hedge effectiveness.
3 In 2023, Net income (loss) includes net realized gains of less than $ 1 million (2022 – gains of $ 1 million) related to the interest component of cross-currency swap settlements which are reported within Interest expense.

The notional amounts and fair value of U.S. dollar-denominated debt designated as a net investment hedge were as follows:

at December 31		
(millions of Canadian $, unless otherwise noted)	**2023**	**2022**
Notional amount	**27,800 (US 21,100)**	32,500 (US 24,000)
Fair value	**26,600 (US 20,200)**	30,800 (US 22,700)

Counterparty Credit Risk

TC Energy's exposure to counterparty credit risk includes its cash and cash equivalents, accounts receivable and certain contractual recoveries, 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, 2023, the Company recorded a $73 million ECL recovery (2022 – an expense of $149 million; 2021 – nil) with respect to the net investment in leases associated with the in-service TGNH pipelines and a $10 million ECL recovery (2022 – $14 million expense; 2021 – nil) 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, 2023 and 2022. At December 31, 2023 and 2022, 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. Certain non-derivative financial instruments included in Cash and cash equivalents, Accounts receivable, Other current assets, Restricted investments, Net investment in leases, 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. Each of these instruments are classified in Level II of the fair value hierarchy, except for the Company's LMCI equity securities which are classified in Level I of the fair value hierarchy.

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	2023		2022	
(millions of Canadian $)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion (Note 21)[1,2]	**(52,914)**	**(52,815)**	(41,543)	(39,505)
Junior subordinated notes (Note 22)	**(10,287)**	**(9,217)**	(10,495)	(9,415)
	(63,201)	**(62,032)**	(52,038)	(48,920)

1 Long-term debt is recorded at amortized cost, except for US$ 2.0 billion (2022 – US$ 1.6 billion) that is attributed to hedged risk and recorded at fair value.

2 Net income (loss) for 2023 included unrealized losses of $ 53 million (2022 – unrealized gains of $ 64 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$2.0 billion of long-term debt at December 31, 2023 (2022 – US$ 1.6 billion). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

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	2023		2022	
(millions of Canadian $)	LMCI Restricted Investments	Other Restricted Investments[1]	LMCI Restricted Investments	Other Restricted Investments[1]
Fair value of fixed income securities[2,3]				
Maturing within 1 year	**1**	**35**	—	54
Maturing within 1-5 years	**8**	**291**	—	106
Maturing within 5-10 years	**1,340**	**—**	1,153	—
Maturing after 10 years	**102**	**—**	77	—
Fair value of equity securities[2,4]	**883**	**—**	749	—
	2,334	**326**	1,979	160

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	2023		2022		2021	
(millions of Canadian $)	LMCI Restricted Investments[1]	Other Restricted Investments[2]	LMCI Restricted Investments[1]	Other Restricted Investments[2]	LMCI Restricted Investments[1]	Other Restricted Investments[2]
Net unrealized gains (losses)	**190**	**13**	(244)	(7)	45	(2)
Net realized gains (losses)[3]	**(34)**	**—**	(32)	—	3	—

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 assets or regulatory liabilities 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, 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 9)					
Commodities[2]	9	—	—	1,195	1,204
Foreign exchange	—	—	10	71	81
	9	—	10	1,266	1,285
Other long-term assets (Note 16)					
Commodities[2]	3	—	—	86	89
Foreign exchange	—	—	—	30	30
Interest rate	—	36	—	—	36
	3	36	—	116	155
Total Derivative Assets	12	36	10	1,382	1,440
Accounts payable and other (Note 18)					
Commodities[2]	(1)	—	—	(1,110)	(1,111)
Foreign exchange	—	—	—	(14)	(14)
Interest rate	—	(18)	—	—	(18)
	(1)	(18)	—	(1,124)	(1,143)
Other long-term liabilities (Note 19)					
Commodities[2]	—	—	—	(75)	(75)
Foreign exchange	—	—	—	(2)	(2)
Interest rate	—	(29)	—	—	(29)
	—	(29)	—	(77)	(106)
Total Derivative Liabilities	(1)	(47)	—	(1,201)	(1,249)
Total Derivatives	11	(11)	10	181	191

1 Fair value equals carrying value.
2 Includes purchases and sales of power, natural gas and liquids.

The balance sheet classification of the fair value of derivative instruments was as follows:

at December 31, 2022 (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 9)					
Commodities[2]	—	—	—	597	597
Foreign exchange	—	—	6	11	17
	—	—	6	608	614
Other long-term assets (Note 16)					
Commodities[2]	—	—	—	62	62
Foreign exchange	—	—	2	15	17
Interest rate	—	12	—	—	12
	—	12	2	77	91
Total Derivative Assets	—	12	8	685	705
Accounts payable and other (Note 18)					
Commodities[2]	(72)	—	—	(584)	(656)
Foreign exchange	—	—	(31)	(158)	(189)
Interest rate	—	(26)	—	—	(26)
	(72)	(26)	(31)	(742)	(871)
Other long-term liabilities (Note 19)					
Commodities[2]	(2)	—	—	(75)	(77)
Foreign exchange	—	—	(4)	(20)	(24)
Interest rate	—	(50)	—	—	(50)
	(2)	(50)	(4)	(95)	(151)
Total Derivative Liabilities	(74)	(76)	(35)	(837)	(1,022)
Total Derivatives	(74)	(64)	(27)	(152)	(317)

1 Fair value equals carrying value.
2 Includes purchases and sales of power, natural gas and liquids.

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 $)	2023	2022	2023	2022
Long-term debt	**(2,630)**	(2,101)	**11**	64

1 At December 31, 2023 and 2022, adjustments for discontinued hedging relationships included in these balances were 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, 2023	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Net sales (purchases)[1,2]	**9,209**	**50**	**(7)**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**4,978**	**2,000**
Millions of Mexican pesos	**—**	**—**	**—**	**20,000**	**—**
Maturity dates	**2024-2044**	**2024-2029**	**2024**	**2024-2026**	**2030-2034**

1 Volumes for power, natural gas and liquids derivatives are in GWh, Bcf and MMBbls, respectively.

2 In 2023, the Company entered into contracts to sell 50 MW of power commencing in 2025 with terms ranging from 15 to 20 years and provided from specified renewable sources in the Province of Alberta.

at December 31, 2022	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Net sales (purchases)[1]	673	(96)	11	—	—
Millions of U.S. dollars	—	—	—	5,997	1,600
Millions of Mexican pesos	—	—	—	9,747	—
Maturity dates	2023-2026	2023-2027	2023-2024	2023-2026	2030-2032

1 Volumes for power, natural gas and liquids derivatives are in GWh, Bcf and MMBbls, 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 $)	2023	2022	2021
Derivative Instruments Held for Trading[1]			
Unrealized gains (losses) in the year			
Commodities	**96**	14	9
Foreign exchange (Note 23)	**246**	(149)	(203)
Realized gains (losses) in the year			
Commodities	**811**	759	287
Foreign exchange (Note 23)	**155**	(2)	240
Derivative Instruments in Hedging Relationships[2]			
Realized gains (losses) in the year			
Commodities	**(2)**	(73)	(44)
Interest rate	**(43)**	(3)	(32)

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.

2 In 2023, there were no gains or losses included in Net Income (loss) relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur (2022 – nil; 2021 – realized loss of $10 million).

Derivatives in cash flow hedging relationships

The components of OCI (Note 27) 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)	**2023**	**2022**	**2021**
Gains (losses) in fair value of derivative instruments recognized in OCI[1]			
Commodities	**—**	(94)	(35)
Interest rate	**—**	36	22
	—	(58)	(13)

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 $)	**2023**	**2022**	**2021**
Fair Value Hedges			
Interest rate contracts[1]			
Hedged items	**(98)**	(30)	—
Derivatives designated as hedging instruments	**(43)**	(1)	—
Cash Flow Hedges			
Reclassification of gains (losses) on derivative instruments from AOCI to Net income (loss)[2,3]			
Commodity contracts[4]	**(85)**	(47)	(22)
Interest rate contracts[1]	**(12)**	(16)	(46)

1 Presented within Interest expense in the Consolidated statement of income.
2 Refer to Note 27, 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.

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, 2023 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative Instrument Assets			
Commodities	**1,293**	**(1,099)**	**194**
Foreign exchange	**111**	**(16)**	**95**
Interest rate	**36**	**(5)**	**31**
	1,440	**(1,120)**	**320**
Derivative Instrument Liabilities			
Commodities	**(1,186)**	**1,099**	**(87)**
Foreign exchange	**(16)**	**16**	**—**
Interest rate	**(47)**	**5**	**(42)**
	(1,249)	**1,120**	**(129)**

1 Amounts available for offset do not include cash collateral pledged or received.

at December 31, 2022 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative Instrument Assets			
Commodities	659	(591)	68
Foreign exchange	34	(33)	1
Interest rate	12	(4)	8
	705	(628)	77
Derivative Instrument Liabilities			
Commodities	(733)	591	(142)
Foreign exchange	(213)	33	(180)
Interest rate	(76)	4	(72)
	(1,022)	628	(394)

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 $149 million and letters of credit of $83 million at December 31, 2023 (2022 – $138 million and $68 million, respectively) to its counterparties. At December 31, 2023, the Company held less than $1 million in cash collateral and $15 million in letters of credit (2022 – less than $1 million and $10 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, 2023, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $3 million (2022 – $19 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, 2023, 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, 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	**1,054**	**229**	**10**	**1,293**
Foreign exchange	**—**	**111**	**—**	**111**
Interest rate	**—**	**36**	**—**	**36**
Derivative Instrument Liabilities				
Commodities	**(1,002)**	**(163)**	**(21)**	**(1,186)**
Foreign exchange	**—**	**(16)**	**—**	**(16)**
Interest rate	**—**	**(47)**	**—**	**(47)**
	52	**150**	**(11)**	**191**

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

In 2023, the Company entered into contracts to sell 50 MW of power commencing in 2025 with terms ranging from 15 to 20 years and 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, 2022 (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	515	142	2	659
Foreign exchange	—	34	—	34
Interest rate	—	12	—	12
Derivative Instrument Liabilities				
Commodities	(478)	(242)	(13)	(733)
Foreign exchange	—	(213)	—	(213)
Interest rate	—	(76)	—	(76)
	37	(343)	(11)	(317)

1 There were no transfers from Level II to Level III for the year ended December 31, 2022.

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)	2023	2022
Balance at beginning of year	**(11)**	(6)
Net gains (losses) included in Net income (loss)	**(2)**	(10)
Net gains (losses) included in OCI	**—**	(3)
Transfers out of Level III	**2**	7
Settlements	**—**	1
Balance at End of Year[1]	**(11)**	(11)

1 Revenues include unrealized losses of $ 2 million attributed to derivatives in the Level III category that were still held at December 31, 2023 (2022 – unrealized losses of $ 10 million).

30. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian $)	2023	2022	2021
(Increase) decrease in Accounts receivable	**(394)**	(575)	(925)
(Increase) decrease in Inventories	**(56)**	(190)	(93)
(Increase) decrease in Other current assets	**618**	118	(141)
Increase (decrease) in Accounts payable and other	**(206)**	(83)	890
Increase (decrease) in Accrued interest	**245**	91	(18)
(Increase) Decrease in Operating Working Capital	**207**	(639)	(287)

31. ACQUISITIONS AND DISPOSITIONS

U.S. Natural Gas Pipelines

Disposition of Equity Interest

On October 4, 2023, the Company completed the sale of a40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf for $5.3 billion (US$3.9 billion). 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.

Liquids Pipelines

Northern Courier

In November 2021, TC Energy completed the sale of its remaining15 per cent equity interest in Northern Courier to a third party for gross proceeds of approximately $35 million resulting in a pre-tax gain of $13 million ($19 million after tax). The pre-tax gain was included in Net gain(loss) on sale of assets in the Consolidated statement of income.

Power and Energy Solutions

Texas Wind Farms

On March 15, 2023, TC Energy closed the acquisition of100 per cent of the Class B Membership Interests in the155 MW Fluvanna Wind Farm located in Scurry County, Texas for US$99 million, before post-closing adjustments. On June 14, 2023, the Company closed the acquisition of100 per cent of the Class B Membership Interests in the 148 MW Blue Cloud Wind Farm located in Bailey County, Texas for US$125 million, before post-closing adjustments. The Fluvanna and Blue Cloud assets have tax equity investors that own 100 per cent of the Class A Membership Interests, to which a percentage of earnings, tax attributes and cash flows are allocated.

32. 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 2023 were $397 million (2022 – $362 million; 2021 – $239 million).

The Company has entered into PPAs with solar and wind-power generating facilities ranging from 2024 to 2038 that require the purchase of generated energy and associated environmental attributes. At December 31, 2023, the total planned capacity secured under the PPAs is approximately 800 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, 2023, TC Energy had approximately $2.1 billion of capital expenditure commitments, primarily consisting of:

- $0.3 billion for its U.S. natural gas pipelines, primarily related to construction costs associated with ANR and other pipeline projects
- $1.3 billion for its Mexico natural gas pipelines related to construction of the Southeast Gateway pipeline.

Contingencies

TC Energy is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2023, the Company had accrued approximately $19 million (2022 – $20 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 amounts involved in such proceedings are not reasonably estimable as the final outcome of such legal proceedings cannot be predicted with certainty. 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, for which the claims are material and there is a reasonable possibility of loss, but have not been assessed as probable and a reasonable estimate of loss cannot be made, 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.

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:

SA Energy Group

Coastal GasLink LP is in arbitration with SA Energy Group (SAEG), which is one of the prime construction contractors on the Coastal GasLink pipeline. While still engaged as prime contractor, SAEG filed a request to arbitrate in February 2022, seeking damages for incremental costs resulting from alleged project delays. In order to mitigate cost, schedule and environmental risk while the project was in active construction, Coastal GasLink LP advanced without prejudice payments to SAEG which Coastal GasLink LP now seeks to recover via set off. By agreement among the parties, the scope of the arbitration is limited to damages for project work completed prior to December 29, 2022. In November 2023, SAEG filed materials purporting to seek damages in excess of $1.1 billion. Coastal GasLink LP continues to dispute the merits of SAEG's claims and to assert its right to set off. Arbitration is scheduled to proceed in late 2024. At December 31, 2023, the final outcome of this matter cannot be reasonably estimated.

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 November 2023, PAPC purports to seek at least $428 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 $1.2 billion. Arbitration is scheduled to proceed in late 2024. At December 31, 2023, the final outcome of this matter cannot be reasonably estimated.

Separately, Coastal GasLink LP has sought to draw down 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 has 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, which is the subject of further court proceedings.

Keystone XL

In 2021, TC Energy filed a Request for Arbitration to formally initiate a legacy North American Free Trade Agreement (NAFTA) claim to recover economic damages resulting from the revocation of the Presidential Permit for the Keystone XL pipeline project. In 2022, the International Centre for Settlement of Investment Disputes formally constituted a tribunal to hear TC Energy's request for arbitration under NAFTA. In April 2023, the tribunal suspended the proceeding, granting a request from the U.S. Department of State to decide the jurisdictional grounds of the case as a preliminary matter. A hearing on the jurisdictional matter is set to occur in second quarter of 2024. In April 2023, the Government of Alberta filed its own request for arbitration, which will proceed separately from the Company's claim. Termination activities undertaken in 2023, including asset dispositions and preservation, will continue through the first half of 2024. The Company will continue to coordinate with regulators, stakeholders and Indigenous groups to meet its environmental and regulatory commitments.

2016 Columbia Pipeline Acquisition Lawsuit

In 2023, the Delaware Chancery 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. The Court awarded US$1 per share in damages to the plaintiffs and total damages, which is presently estimated at US$400 million plus statutory interest. Post-trial briefing and argument has concluded and a decision from the Court allocating liability as between TC Energy and the CPG executives is expected sometime in the first half of 2024. Until the allocation of damages is known, the amount that TC Energy is liable for cannot be reasonably estimated, therefore, the Company has not accrued a provision for this claim at December 31, 2023. Management expects to proceed with an appeal following the Court's determination of total damages and TC Energy's allocated share.

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 construction services and the payment of liabilities. 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		**2023**		**2022**	
(millions of Canadian $)	**Term**	**Potential Exposure**[1]	**Carrying Value**	**Potential Exposure**[1]	**Carrying Value**
Sur de Texas	Renewable to 2053	**97**	**—**	100	—
Bruce Power	Renewable to 2065	**88**	**—**	88	—
Other jointly-owned entities	to 2043	**80**	**3**	81	3
		265	**3**	269	3

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

33. VARIABLE INTEREST ENTITIES

Consolidated VIEs

A significant portion of the Company's assets are held through VIEs in which the Company holds a100 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 $)	2023[1]	2022
ASSETS		
Current Assets		
Cash and cash equivalents	**190**	60
Accounts receivable	**476**	98
Inventories	**90**	32
Other current assets	**49**	14
	805	204
Plant, Property and Equipment	**27,649**	3,997
Equity Investments	**823**	748
Regulatory Assets	**12**	—
Goodwill	**439**	449
	29,728	5,398
LIABILITIES		
Current Liabilities		
Accounts payable and other	**1,135**	234
Accrued interest	**210**	18
Current portion of long-term debt	**28**	31
	1,373	283
Regulatory Liabilities	**280**	78
Other Long-Term Liabilities	**56**	1
Deferred Income Tax Liabilities	**22**	16
Long-Term Debt	**11,388**	2,136
	13,119	2,514

1 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 24, Non-controlling interests, and Note 31, 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 $)	2023	2022
Balance Sheet Exposure		
Equity investments		
Bruce Power	**6,241**	5,783
Pipeline equity investments and other	**1,411**	1,148
Off-Balance Sheet Exposure[1]		
Bruce Power	**1,538**	2,025
Coastal GasLink[2]	**855**	3,300
Pipeline equity investments	**58**	58
Maximum exposure to loss	**10,103**	12,314

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. At December 31, 2023, the total capacity committed by TC Energy under this subordinated loan agreement was $3,375 million (December 31, 2022 – $ 1,262 million). In the year ended December 31, 2023, $ 2,520 million was drawn on the subordinated loan, reducing the Company's funding commitment under the subordinated loan agreement to $855 million. Refer to Note 8, Coastal GasLink, for further information.

In July 2022, the Company entered into revised project agreements relating to its investment in Coastal GasLink LP and committed to make additional equity contributions, which did not result in a change in the Company's 35 per cent ownership. These revisions and additional equity contributions were determined to be a VIE reconsideration event for TC Energy's investment in Coastal GasLink LP. The Company performed a re-assessment of control and determined that Coastal GasLink LP continued to meet the definition of a VIE in which the Company held a variable interest. The re-assessment further determined that TC Energy was not the primary beneficiary of Coastal GasLink LP as the Company does not have the power, either explicit or implicit through voting rights or otherwise, to direct the activities that most significantly impact the economic performance of Coastal GasLink LP. Accordingly, the Company continued to account for its investment using the equity method of accounting. Refer to Note 8, Coastal GasLink, for additional information.

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the use of:

- our report dated February 15, 2024 on the consolidated financial statements of TC Energy Corporation (the "Company") which comprise the consolidated balance sheets as at December 31, 2023 and 2022, 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, 2023, and the related notes, and
- our report dated February 15, 2024 on the effectiveness of the Company's internal control over financial reporting as of December 31, 2023

each of which is included in the Annual Report on Form 40-F of the Company for the fiscal year ended December 31, 2023.

We also consent to the incorporation by reference of such reports in the:

- Registration Statements No. 333-5916, No. 333-8470, No. 333-9130, No. 333-151736, No. 333-184074, No. 333-227114 and No. 333-237979 on Form S-8 of TC Energy Corporation;
- Registration Statements No. 33-13564 and No. 333-6132 on Form F-3 of TC Energy Corporation;
- Registration Statements No. 333-208585, No. 333-250988 and No. 333-252123 on Form F-10 of TC Energy Corporation; and,
- Registration Statement No. 333-267323 and No. 333-276558 on Form F-10 of TransCanada PipeLines Limited.

/s/ KPMG LLP
Chartered Professional Accountants

February 15, 2024
Calgary, Canada

EXHIBIT 31.1

Certifications

I, François L. Poirier, certify that:

1. I have reviewed this annual report on Form 40-F of TC Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated February 16, 2024

/s/ FRANÇOIS L. POIRIER
François L. Poirier
President and Chief Executive Officer

Certifications

I, François L. Poirier, certify that:

1. I have reviewed this annual report on Form 40-F of TransCanada PipeLines Limited;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated February 16, 2024

/s/ FRANÇOIS L. POIRIER

François L. Poirier
President and Chief Executive Officer

Certifications

I, Joel E. Hunter, certify that:

1. I have reviewed this annual report on Form 40-F of TC Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated February 16, 2024

/s/ JOEL E. HUNTER

Joel E. Hunter
Executive Vice-President and Chief Financial Officer

Certifications

I, Joel E. Hunter, certify that:

1. I have reviewed this annual report on Form 40-F of TransCanada PipeLines Limited;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated February 16, 2024

/s/ JOEL E. HUNTER

Joel E. Hunter
Executive Vice-President and Chief Financial Officer

EXHIBIT 32.1

TC ENERGY CORPORATION

450 – 1st Street S.W.
Calgary, Alberta, Canada
T2P 5H1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
UNDER SECTION 906 OF SARBANES-OXLEY ACT OF 2002

I, François L. Poirier, the Chief Executive Officer of TC Energy Corporation (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify, in connection with the Company's Annual report as filed on Form 40-F for the fiscal year ended December 31, 2023 with the Securities and Exchange Commission (the "Report"), that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ FRANÇOIS L. POIRIER
François L. Poirier
Chief Executive Officer
February 16, 2024

TRANSCANADA PIPELINES LIMITED

450 – 1st Street S.W.
Calgary, Alberta, Canada
T2P 5H1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
UNDER SECTION 906 OF SARBANES-OXLEY ACT OF 2002

I, François L. Poirier, the Chief Executive Officer of TransCanada PipeLines Limited (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify, in connection with TC Energy Corporation's Annual report as filed on Form 40-F for the fiscal year ended December 31, 2023 with the Securities and Exchange Commission (the "Report"), that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ FRANÇOIS L. POIRIER
François L. Poirier
Chief Executive Officer
February 16, 2024

EXHIBIT 32.2

TC ENERGY CORPORATION

450 – 1st Street S.W.
Calgary, Alberta, Canada
T2P 5H1

CERTIFICATION OF CHIEF FINANCIAL OFFICER
UNDER SECTION 906 OF SARBANES-OXLEY ACT OF 2002

I, Joel E. Hunter, the Chief Financial Officer of TC Energy Corporation (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify, in connection with the Company's Annual report as filed on Form 40-F for the fiscal year ended December 31, 2023 with the Securities and Exchange Commission (the "Report"), that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ JOEL E. HUNTER
Joel E. Hunter
Chief Financial Officer
February 16, 2024

TRANSCANADA PIPELINES LIMITED

450 – 1st Street S.W.
Calgary, Alberta, Canada
T2P 5H1

CERTIFICATION OF CHIEF FINANCIAL OFFICER
UNDER SECTION 906 OF SARBANES-OXLEY ACT OF 2002

I, Joel E. Hunter, the Chief Financial Officer of TransCanada PipeLines Limited (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify, in connection with TC Energy Corporation's Annual report as filed on Form 40-F for the fiscal year ended December 31, 2023 with the Securities and Exchange Commission (the "Report"), that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ JOEL E. HUNTER
Joel E. Hunter
Chief Financial Officer
February 16, 2024



Incentive compensation recoupment and holdback policy.

Purpose and scope

The purpose of this Policy is to provide direction for the process of recouping Erroneously Awarded Compensation in order to satisfy the requirements of the NYSE Listing Standards and Rule 10D-1 as adopted by the U.S. SEC to implement Section 954 of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010.

This Policy will operate in addition to any legal requirements that may apply to the Company and its Employees, officers and directors. This Policy is in addition to any other action or remedy available to the Company against such individuals under applicable law, policy or contract, up to and including termination of employment and/or legal action for breach of fiduciary duty or fraud.

This Policy applies to all Covered Executives of TC Energy Corporation and their beneficiaries, heirs, executors, administrators or other legal representatives.

Policy

1 Recoupment event

1.1 If TC Energy Corporation is required to prepare a Restatement, then, as determined by the Human Resources Committee, the Covered Executive's Incentive-Based Compensation will be subject to forfeiture, recovery and recoupment, subject to the following:

a) This Policy applies to Incentive-Based Compensation received by a Covered Executive: (i) on or after October 2, 2023, (ii) after beginning services as a Covered Executive, and any subsequent changes in a Covered Executive's employment status, including retirement or termination of employment, do not affect the Company's rights to recoup Erroneously Awarded Compensation pursuant to this Policy, and (iii) if the Covered Executive served as a Covered Executive at any time during the performance period for such Incentive-Based Compensation.

b) The amount to be forfeited or recouped will equal the Erroneously Awarded Compensation. The Human Resources Committee will take actions necessary to recoup the Erroneously Awarded Compensation reasonably promptly following a Restatement. Where the amount of Erroneously Awarded Compensation is not subject to

mathematical recalculation directly from the information in the Restatement, the amount must be based on a reasonable estimate of the effect of the Restatement on stock price or total shareholder return upon which the Incentive-Based Compensation was received. The Company will maintain documentation of the determination of that reasonable estimate and provide such documentation to the New York Stock Exchange (NYSE). The amount of the Erroneously Awarded Compensation must not be reduced based on, or otherwise calculated with regard to, any taxes paid by the Covered Executive with respect to such amounts.

c) This Policy must only apply to Incentive-Based Compensation that was received during the Applicable Period and that was received (or would have been settled in the absence of an elective deferral of payment by the individual) while TC Energy Corporation has a class of securities listed on a U.S. national securities exchange or a national securities association. For purposes of this Policy, Incentive-Based Compensation is deemed received in the fiscal period during which the Financial Reporting Measure(s) specified in the applicable Incentive-Based Compensation is attained, even if the payment or grant of the Incentive-Based Compensation occurs after the end of such fiscal period.

1.2 In the event of a recoupment of Erroneously Awarded Compensation from a Covered Executive, the Human Resources Committee may also seek reimbursement of all reasonable costs, including legal fees, incurred in connection with the recoupment of the Erroneously Awarded Compensation from such Covered Executive.

2 Impracticability

2.1 The Company must recoup any Erroneously Awarded Compensation unless the conditions set forth in the following clauses (a), (b) or (c) are met and such recoupment would be impracticable, as determined by the Human Resources Committee in accordance with Rule 10D-1 and the NYSE Listing Standards. No recoupment will be required if:

a) the direct expense paid to a third party to assist in enforcing this Policy would exceed the amount to be recouped, provided that before concluding that it would be impractical to recoup any amount of Erroneously Awarded Compensation based on this clause (a), the Company must make a reasonable attempt to recoup such Erroneously Awarded Compensation, document such reasonable attempt(s) and provide such documentation to the NYSE;

b) recoupment would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to Employees of the Company, to fail to meet the applicable requirements of the U.S. Internal Revenue Code, or any successor provision thereof; or

c) recoupment would violate home country law where that law was adopted prior to November 28, 2022, provided that before concluding that it would be impractical to recoup any amount of Erroneously Awarded Compensation based on this clause (c), the Company must obtain an opinion of home country legal counsel, acceptable to the NYSE, that recoupment would result in such violation, and must provide such opinion to the NYSE.

3 No indemnification

3.1 The Company must not indemnify any current or former Covered Executive against the loss of Erroneously Awarded Compensation, and must not pay, or reimburse any Covered Executives for premiums, for any insurance policy to fund such Covered Executive's potential repayment obligations.

4 Other recoupment rights

4.1 The Human Resources Committee may require that any employment agreement, equity award agreement, or similar agreement entered into, amended or restated on or after the Effective Date must, as a condition to the grant of any benefit thereunder, require a Covered Executive to agree to abide by the terms of this Policy and the application of this Policy to any award made prior to the Effective Date.

5 Notification requirements

5.1 In the event of a Restatement or potential Restatement, the Financial Reporting department must notify the Corporate Secretarial Legal department and the Human Resources department as soon as reasonably possible.

6 Effective Date

6.1 This Policy is effective as of the Effective Date.

6.2 To the extent there are any inconsistencies, as of the Effective Date, this Policy supersedes all prior contracts, agreements and understandings, written or oral, with any Covered Executive. In the event any contract, agreement or understanding with any Covered Executive is inconsistent with the terms of this Policy, the terms of this Policy will govern.

6.3 The terms of this Policy must apply to any Incentive-Based Compensation that is received by a Covered Executive on or after October 2, 2023, even if such Incentive-Based Compensation was approved, awarded, granted or paid to the Covered Executive prior to October 2, 2023. Subject to applicable law, the Human Resources Committee may effect forfeiture or recoupment under this Policy from any amount of compensation approved, awarded, granted, payable or paid to the Covered Executive prior to, on or after October 2, 2023.

Your responsibility

Employees must follow all applicable provisions and the spirit and intent of this corporate governance document and support others in doing so. Employees must promptly report any suspected or actual violation of this corporate governance document through available channels so that TC Energy can investigate and address it appropriately. Employees who violate this corporate governance document or knowingly permit others under their supervision to violate it, may be subject to appropriate corrective action, up to and including termination of employment or contract, as applicable, in accordance with the Company's corporate governance documents, employment practices, contracts, collective bargaining agreements and processes.

Interpretation and administration

The Company has sole discretion to interpret, administer and apply this corporate governance document and to change it at any time to address new or changed legal requirements or business circumstances.

Non-retaliation

TC Energy supports and encourages Employees and Contractors to report suspected violations of corporate governance documents, applicable laws, regulations, and authorizations, as well as hazards, potential hazards, incidents involving health and safety or the environment, and near hits. Such reports can be made through available channels. TC Energy takes every report seriously and investigates it to identify facts and, when warranted, makes improvements to our corporate governance documents and practices. All Employees and Contractors making reports in good faith will be protected from retaliation, and all Employees and Contractors must report if they or someone they know is being or has been retaliated against for reporting. Good Faith Reporting will not protect Employees and Contractors who make intentionally false or malicious reports, or who seek to exempt their own negligence or willful misconduct by the act of making a report.

Definitions

Applicable Period means the three completed fiscal years prior to the earlier of:

- the date TC Energy Corporation's Board of Directors, a committee of the Board of Directors, or officer(s) authorized to take such action if action by the Board of Directors is not required, concludes, or reasonably should have concluded, that TC Energy Corporation is required to prepare a Restatement; or
- the date a court, regulator, or other legally authorized body directs TC Energy Corporation to prepare a Restatement.

In addition to the last three completed fiscal years described in the preceding sentence, the Applicable Period includes any transition period (that results from a change in TC Energy Corporation's fiscal year) within or immediately following those three completed fiscal years; provided, however, a transition period between the last day of TC Energy Corporation's previous fiscal year end and the first day of its new fiscal year that comprises a period of nine to 12 months would be deemed a completed fiscal year for purposes of the Applicable Period.

Covered Executive means all of TC Energy Corporation's current and former executive officers, as determined by the Human Resources Committee, in accordance with the Listing Standards and Rule 10D-1 and the definition of executive officer as defined in Rule 10D-1(d).

Effective Date means December 1, 2023.

Employee means full-time, part-time, temporary and student employees of the Company.

Erroneously-Awarded Compensation means the amount of Incentive-Based Compensation received by a Covered Executive that exceeds the amount of Incentive-Based Compensation that otherwise would have been received had it been determined based on the Restatements.

Exchange Act means the U.S. Securities Exchange Act of 1934, as amended.

Financial Reporting Measures means measures that are determined and presented in accordance with the accounting principles used in preparing TC Energy Corporation's financial statements, and any measures that are derived wholly or in part from such measures, including stock price and total shareholder return.

Good Faith Reporting means an open, honest, fair and reasonable report without malice or ulterior motive.

Human Resources Committee means the Human Resources Committee of the TC Energy Corporation Board of Directors.

Incentive-Based Compensation means all compensation, such as cash bonuses or other cash incentive awards (including any deferred element thereof), and vested and unvested equity awards (including options, restricted stock and restricted stock units, performance stock unit awards and performance stock awards) from the Company that is granted, earned, or vested based wholly or in part upon the attainment of a Financial Reporting Measure. For the avoidance of doubt, Incentive-Based Compensation does not include annual salary, compensation awarded based on completion of a specified period of service, or compensation awarded based on subjective standards, strategic measures, or operational measures, unless also based on attainment of a Financial Reporting Measure.

NYSE Listing Standards means Section 303A.14 of the New York Stock Exchange Listed Company Manual.

Restatement means an accounting restatement of TC Energy Corporation's financial statements due to material noncompliance with any financial reporting requirement under the U.S. federal securities laws, including any required accounting Restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements, or that

would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period.

Rule 10D-1 means Rule 10D-1 promulgated under the Exchange Act.

TC Energy or the **Company** means TC Energy Corporation and its wholly-owned subsidiaries and operated entities.

U.S. SEC means the United States Securities and Exchange Commission.

References

Related corporate governance and supporting documents

- Code of Business Ethics Policy

Other References

- Dodd-Frank Wall Street Reform
- NYSE Listing Standards
- U.S. Internal Revenue Code
- U.S SEC

How to contact us

- Policy Questions and Comments

TC Energy's reporting channels

- Ethics Helpline
- Corporate Compliance
- Internal Audit
- Human Resources
- Legal department
- Compliance Coordinators

EXHIBIT 99.1

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MAKING THE RIGHT CHOICES — DOING THE RIGHT THING

TC Energy's Code of Business Ethics (COBE) Policy



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MESSAGE FROM FRANÇOIS POIRIER

At TC Energy, we know what we do – and just as importantly – how we do it, matters. Our daily decisions and activities impact the Company and the communities we serve. That's why we must ensure our actions are aligned with our values. It is important that stakeholders, rightsholders and the public are confident they can count on us to act with integrity no matter the circumstances.

Our corporate values – safety, innovation, responsibility, collaboration and integrity – form the foundation of how we do business. Our Code of Business Ethics (COBE) helps us put those values into practice by clarifying what honest and ethical conduct look like in action.

Every member of the TC Energy team is expected to read, understand and comply with the principles and requirements set out in COBE and is required to complete annual COBE training and certification. We encourage people to refer regularly to COBE to help guide decisions in ethical situations they may face at work, since it offers clear guidelines and examples of expected behaviour. COBE also provides a framework for asking questions and highlights resources in place to report concerns.

Our reputation as a safe, reliable and honest company that moves, generates and stores the energy North America relies on is critical to our continued success. It will take all of us consistently living our values every day to ensure TC Energy continues to be a company that is trusted to make the right choices and do the right thing.

François Poirier
President & CEO



OUR EXPECTATIONS AND YOUR RESPONSIBILITIES

The Code of Business Ethics (COBE) Policy reinforces TC Energy Corporation's (the Company's or TC Energy's) requirements and expectations for conducting business and behaviours, and provides guidance to ensure our daily activities and decisions appropriately reflect, and are consistent with, our corporate values of safety, innovation, responsibility, collaboration and integrity. Doing business ethically, fairly and responsibly is not just a concept at TC Energy, it is a commitment we make every day.

The COBE Policy functions in conjunction with TC Energy's other policies and applies to all Employees, directors, officers and Contingent Workforce Contractors (CWCs) of TC Energy and its wholly-owned subsidiaries and/or operated entities in all countries in which TC Energy conducts business. In addition, TC Energy has a Contractor Code of Business Ethics (COBE) Policy that communicates the same requirements in the COBE Policy, as applicable.

You must understand these requirements and know how to meet TC Energy's standards. We expect compliance with all applicable laws, regulations, policies and rules.

Have a question? We're here to help. If you are unsure of what standard you need to comply with, ask. Contact information is located in the Resources section of this document.

Failure to comply with the requirements set out in this document, or any TC Energy policy, may lead to serious consequences and corrective action up to and including termination of employment or contract.

Look for this symbol throughout the COBE Policy to guide you to relevant policies available on our websites at TCEnergy.com/about/governance and on our Policy Listing 1TC webpage.



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ETHICS HELP LINE
Canada / U.S.: 1-888-920-2042
Mexico: 800-283-2783 (if calling from a cell phone)
0-800-283-2783 (if calling from a land line)
TCEnergy.com/about/governance/code-of-business-ethics

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OUR VALUES

Safety

We believe zero is real. All injuries and occupational illnesses are preventable. Our Personnel are expected to speak up about unsafe conditions and behaviours, take action to address concerns or stop unsafe work, and look out for each other 24/7.

Innovation

We do things differently – we turn challenge into opportunity and ideas into creative solutions. We challenge assumptions, show up curious and encourage new ideas.

Responsibility

We care for the environment and minimize our impact. We make a positive difference in our communities and consider sustainability in everything we do. We deliver for our customers and take personal accountability for results.

Collaboration

We engage others, participate in healthy debate and respect different perspectives. We work together to find better ways to solve problems and create value. We find win-win outcomes for our shareholders and our customers.

Integrity

We act with high ethical standards, treat others with honesty and respect and keep promises and commitments to stakeholders

Our Commitment Statement



LIVING OUR VALUES

- Making the right choices and doing the right thing
- Reporting safety, legal and ethical violations
- Leader responsibilities
- Zero is real: Protecting health, safety and the environment
- Life Saving Rules
- Alcohol and drug use and being fit for work
- Human rights
- Diversity and employment equity
- Harassment and violence-free workplace Protecting everyone from weapons in the workplace

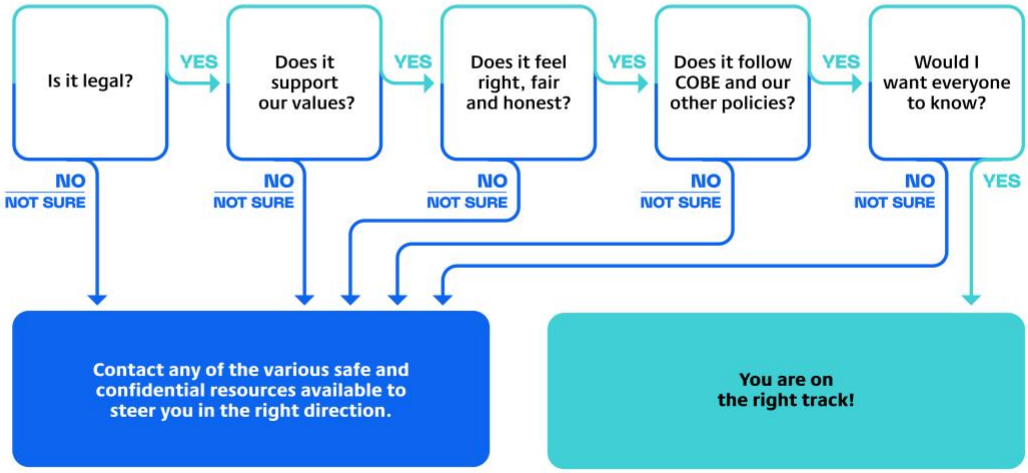


MAKING THE RIGHT CHOICES AND DOING THE RIGHT THING

At TC Energy, making the right choices and doing the right thing aren't just words – these are fundamental requirements to how we do business that all Personnel must carry out in everything we do. But, what does it really mean to make the right choices and do the right thing? At a minimum, it means following the principles set out in COBE, including:

- We report all health, safety and environment related hazards, potential hazards, incidents, near hits and unsafe acts
- We comply with the applicable legal requirements and policies that impact us in our daily work
- We report, through appropriate internal channels or the Ethics Help Line, any instances of actual or potential non-compliance with legal requirements or with our policies that we become aware of
- We do not retaliate against anyone for good-faith reporting
- We support others in making the right choices and doing the right thing

Even if we try our best to make the right choices and do the right thing, there are times when the right thing isn't completely clear. It's at those times that we need to ask ourselves some necessary questions. The below guide to making the right choices and doing the right thing is intended to help you identify the right path in those situations.



REPORTING SAFETY, LEGAL AND ETHICAL VIOLATIONS

We report actual or potential non-compliances with our policies or our legal requirements, so they can be addressed appropriately. Retaliation for Good Faith Reporting is prohibited at TC Energy and your confidentiality and identity will be protected to the greatest extent possible.

ETHICS HELP LINE

Canada / U.S.: 1-888-920-2042
Mexico: 800-283-2783 (if calling from a cell phone)
0-800-283-2783 (if calling from a land line)
TCEnergy.com/about/governance/code-of-business-ethics

How do I report an issue or seek guidance?

You are required to report any actual or suspected violation of the law or COBE and all health, safety and environment related hazards, potential hazards, incidents, near hits and unsafe acts of which you may become aware. We take every report seriously and provide immunity from disciplinary action for Good Faith Reporting of incidents and issues.

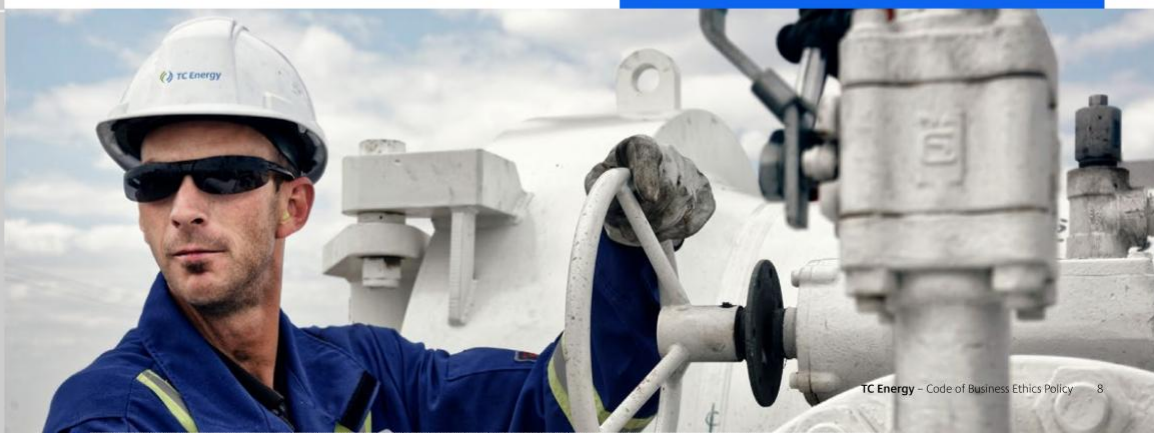
Resources

To report an issue, or if you would like guidance on how to make the right choices and do the right thing in a particular situation, the following resources are available to you:

- Your leader
- Your Human Resources Consultant
- Your Compliance Coordinator
- Corporate Compliance
- Internal Audit
- Legal department
- Privacy Office
- Harassment Investigation Coordinator
- Safety Personnel
- TC Energy's Environment Health and Safety Management (EHSM) Incident Management System

For contact information – click here.

If you are uncomfortable speaking to any of these resources or if you would like to remain anonymous, you can contact the Ethics Help Line.



ZERO IS REAL

Protecting health, safety and the environment

Our commitment to safety isn't just a mantra – it's how we work 24/7, 365 days of the year across our entire organization. What started as a foundational value within our safety department decades ago has now come to mean much more to our company. We believe zero is real, and today – for us – zero means: All harm, loss and incidents are preventable.

We expect all Personnel to share TC Energy's commitment to safety.

Whether you work in a field location or in an office setting, you must always ensure that you comply with all health, safety and environment related legal requirements, as well as the requirements set out by TC Energy in COBE and applicable policies.

If it isn't safe, we won't do it. By reinforcing a disciplined set of rules and providing rigorous training, we approach every day with our goal of a zero-incident workplace.

Zero is real



TC ENERGY'S LIFE SAVING RULES

TC Energy's Life Saving Rules guide the way we work and help us hold each other accountable to the highest possible safety standards.

TC Energy's Life Saving Rules are:

- Drive safely and without distraction
- Use the appropriate personal protective equipment (PPE)
- Conduct a pre-job safety analysis (JSA)
- Work with a valid work permit when required
- Obtain authorization before entering a confined space
- Verify isolation before work begins
- Protect ourselves against a fall when working at heights
- Follow prescribed lift plans and techniques
- Control excavations and ground disturbances

Committing to TC Energy's Life Saving Rules means meeting our goal of everyone going home safe from our offices, facilities and project sites, every day. Nothing is more important.

We report all health, safety and environment related hazards, potential hazards, incidents, near hits and unsafe acts. We take every report seriously, investigate to identify facts and ensure immunity from disciplinary action for the Good Faith Reporting of all incidents and issues.

QUESTION: *I'm working on a big project and it's very important to the Company that it be completed on-time and on-budget. I'm concerned that I might be injured if I rush my work, but I'm feeling a lot of pressure to do so. What should I do?*

ANSWER: *You should never compromise your or anyone else's safety. If someone is pressuring you to do so, you should report the issue.*



ALCOHOL AND DRUG USE AND BEING FIT FOR WORK

We do not compromise our ability to do our jobs or the safety of others through the use of intoxicants, including alcohol, drugs or medications, whether they are legal or not.

Given the nature of TC Energy's business, it is essential that all Personnel be fit to perform their jobs. The use of alcohol or drugs can impair your judgment and productivity and can lead to serious accidents and health and safety concerns – not only for yourself, but also for your coworkers and the public.

Alcohol and Drug Policy

TC Energy takes a zero-tolerance approach toward the use of alcohol, drugs and intoxication while working. You must always be fit for work while engaged in any TC Energy business. Inability to do so will result in serious consequences including being removed from our site(s) and subject to appropriate corrective action, up to and including termination of employment or contract.

What does being fit for work mean?

Fit for work means being able to safely and acceptably perform your assigned duties without any limitations due to the use or after-effects of any intoxicants. This can include legally-obtained medications (prescription and over the counter) which have the potential to change or adversely affect the way a person thinks, feels, or acts.



HUMAN RIGHTS

Consistent with Our Commitment Statement, TC Energy does not tolerate human rights abuses. In our business activities, including engaging with Indigenous groups and stakeholders across Canada, the United States and Mexico, we are committed to respecting human rights. We will not be complicit with, nor engage in, any business activity that supports or facilitates abuse of human rights.

As a participant in the United Nations (UN) Global Compact, TC Energy supports the Ten Principles of the UN Global Compact on human rights, labour, environment and anti-corruption. We are committed to making the UN Global Compact and its principles part of the strategy, culture and day-to-day operations of our company, and to engage in collaborative projects which advance the broader development goals of the UN, particularly the Sustainable Development Goals.

TC Energy considers the International Bill of Human Rights, which consists of the Universal Declaration of Human Rights, and the core International Labour Organization (ILO) Conventions when adopting human rights best practices. This enables the Company to comply with all applicable international standards, federal, provincial, state, and local laws, rules, regulations, orders, and ordinances, including, without limitation, environmental protection, energy, health and safety, and labor laws and regulations, as well as applicable industry codes and standards.

We stand firmly against the use of forced labour, including child labour, prison labour, bonded labour, military labour, modern forms of slavery, human trafficking and any form of physical or mental abuse within our business and operations, including the Contractors we do business with. TC Energy monitors and assesses its Contractors for compliance with human rights requirements, and may terminate business relationships in the event violations are confirmed.

In addition to TC Energy complying with applicable legislated compensation standards, such as minimum wage, wage payment, maximum work hours, mandatory holidays, progressive remuneration in case of overtime and benefits laws, we are committed to providing a fair living wage for all Employees. Employment of individuals below the minimum age permitted by local law is strictly prohibited.

Respect for human rights is covered in TC Energy's annual online Code of Business Ethics training and certification, as well as other related training, as required. Additional mandatory online training includes, but is not limited to, the following courses:

- Health and Safety Core training
- Inclusion and Unconscious Bias training
- Privacy and Protecting Personal Information training
- Respectful Workplace training

Our Commitment Statement



DIVERSITY, EMPLOYMENT EQUITY AND EQUAL OPPORTUNITY

TC Energy believes that our differences make us stronger and encourages a culture of diversity, inclusion and respect. We prohibit any form of discrimination and require reasonable accommodation of differences. We expect Personnel to create and reinforce an inclusive, creative and productive work environment in which everyone is accepted and respected.

HARASSMENT AND VIOLENCE–FREE WORKPLACE

Everyone deserves to do their job in a safe, respectful, and inclusive workplace, without fear of harassment or violence.

You must always be respectful to our Employees and Contractors and be sensitive to the way in which others may react to your behaviours, comments, gestures or contacts. Always try to resolve differences in a calm and respectful manner, without resorting to insults, threats or violence.

TC Energy prohibits any behaviour, including displaying any statements, messages, or images (e.g., on clothing, stickers on hard hats, decals on vehicles, etc.), that is:

- Intimidating
- Hostile
- Offensive
- Threatening
- Violent
- Demeaning or humiliating
- Of a sexual nature
- Creating an inappropriate work environment

TC Energy will take allegations of harassment and violence seriously and address them promptly in a respectful, fair and thorough manner by trained investigators. If required, TC Energy will take appropriate corrective action, up to and including termination of employment or contract.

TC Energy requires you to be tolerant, inclusive and to demonstrate respect for others.

TC Energy requires that we treat one another with dignity and respect, and we are committed to maintaining an inclusive and respectful work environment that is free of harassment and violence.

Equal Employment Opportunity and Non-Discrimination Policy

Harassment-Free Workplace Policy Canada • U.S. • Mexico

Reasonable Workplace Accommodation Policy

In particular, you must never take actions or make unwanted comments or gestures or discriminate against anyone on the basis of:

- Gender
- Race
- National or ethnic origin
- Colour
- Disability
- Religion
- Age
- Sexual orientation
- Gender identity
- Marital status
- Family status
- Veteran status
- National Guard or reserve unit obligations
- A criminal conviction



PROTECTING EVERYONE FROM WEAPONS IN THE WORKPLACE

Unless otherwise prohibited by law, we prohibit the possession, use, carrying and transportation of any dangerous or potentially dangerous weapons, as defined by TC Energy's Weapons in the Workplace Policy, when conducting Company business:

- On or off all Company owned or controlled premises
- In all Company vehicles (whether owned, leased or rented)
- In all personal vehicles being used while conducting Company business.

For individuals in jurisdictions that permit firearms to be kept in personal vehicles, the vehicle must be locked, firearms must be hidden from plain view and be kept within a locked case or container within the vehicle.

Weapons in the Workplace Policy

Individuals who are licensed to carry firearms (openly or in a concealed manner) are not exempt from our Policy.



ETHICAL BUSINESS CONDUCT

- Avoiding conflicts of interest
- Personal Relationships
- Gifts, invitations and entertainment
- Engaging Government Officials
- Political contributions and lobbying
- International trade
- Insider trading
- Complying with regulatory requirements
- Inter-affiliate interactions
- Competing fairly
- Accounting, financial reporting and fraud prevention
- Preventing money laundering



AVOIDING CONFLICTS OF INTEREST

We must act in the best interests of TC Energy, avoiding any situation that could place us in a conflict of interest, or create the perception of a conflict of interest. If, and when, a conflict of interest arises, you are required to report the conflict in a timely manner so it can be appropriately investigated and addressed.

You should never make or influence business decisions on behalf of TC Energy based on personal relationships, bias or the potential for personal gain.

Some examples of conflict of interest can include, but are not limited to:

- Gifts, invitations and entertainment
- Outside business activities
- Corporate opportunities
- Directorships or other board positions outside of TC Energy
- Director independence
- Personal Relationships
- Intimate Relationships

Conflict of Interest and Integrity Policy

Integrity is one of our core values. In simple terms this means making the right choices and doing the right thing – always. At TC Energy, this is part of who we are and how we do business, every day.

What is a conflict of interest?

Conflict of interest means a situation in which Personnel have private interests that could conflict with their ability to act in good faith and the best interests of the Company, or where they may improperly benefit from knowledge acquired at the Company which is not available to the general public.



PERSONAL RELATIONSHIPS

Personnel who have a Personal Relationship within the Company must not be in a direct or indirect reporting relationship with each other. In particular, the Company prohibits all Intimate Relationships between individuals in a direct or indirect reporting relationship.

If Personnel are not certain whether a Personal Relationship within the Company is permissible, they should immediately discuss their situation with their TC Energy leader, HR Business Partners, or HR Governance.

QUESTION: *I want to hire someone who I know has a family member already working for TC Energy. Is that allowed?*

ANSWER: *Yes, it is acceptable to hire someone (Employee or CWC) who has family members already working for TC Energy provided that doing so does not result in the person directly or indirectly (through other leader(s)) reporting to their family member. The onus is on all Personnel to notify HR Governance when they become aware of a Personal Relationship where there is a direct or indirect reporting relationship within the Company.*



OUTSIDE BUSINESS ACTIVITIES AND OUTSIDE DIRECTORSHIPS

Personnel must not engage in outside business activities (e.g., as a consultant, employee, or director) or Advisory Relationships that could conflict with, or be perceived to conflict with, or are detrimental to the interests of TC Energy, and which may include:

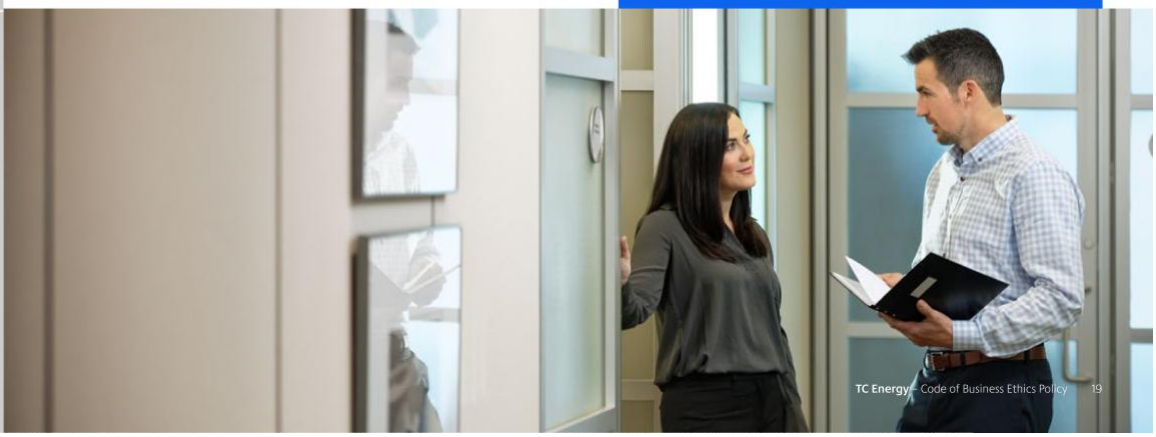
- Owning, controlling or directing a material financial interest (greater than one per cent) in a competitor, or in a vendor, supplier, customer or other business which does or seeks to do business with TC Energy
- Advising or being involved in a business that competes with TC Energy or that does or seeks to do business with TC Energy
- Outside business activities that interfere with Personnel's day-to-day responsibilities at TC Energy
- An outside business activity that requires Personnel to violate their confidentiality or other obligations to TC Energy

TC Energy Personnel who have a Family Relationship with a supplier or potential supplier to the Company must ensure that they are not involved in the selection process or in directing or influencing the work of the supplier to whom they are related.

In cases where the spouse, common law partner, or other family member of Personnel owns, controls, or directs a material financial interest in any of the outside business activities, that Personnel must contact the Corporate Compliance department for guidance.

Personnel must declare all outside business activities and Advisory Relationships that could conflict with or be perceived to conflict with the interests of TC Energy to the Corporate Compliance department for guidance. Any outside business activities must be conducted outside of TC Energy work hours since your time and attention during TC Energy work hours is expected to be directly related to your employment with TC Energy.

Personnel must declare all Outside Directorship positions on a board (e.g., board chair, treasurer, secretary, member, etc.) to Corporate Secretarial for review and approval, prior to accepting the position or upon joining the Company.



OTHER POTENTIAL CONFLICTS OF INTEREST

Corporate opportunities

Personnel must not take personal advantage of a business opportunity that you discover through the use of Company assets, property, information or your position with TC Energy, or use Company assets, property, information or your position with TC Energy for personal gain or to compete with TC Energy.

Political office, appointments to boards or tribunals

Personnel may not serve in a political office or on an administrative board or tribunal, if that office, board or tribunal has or may have decision-making authority in respect of any aspect of TC Energy's business (such as the approval of projects or the issuing of permits).

Executive leadership team - other business activities

In addition to the conditions set out in the outside business activities and outside directorships section above, prior to serving in any capacity in an unaffiliated organization, the Chief Executive Officer and any member of the Executive Leadership Team must obtain the consent of the Chair of the Governance Committee.

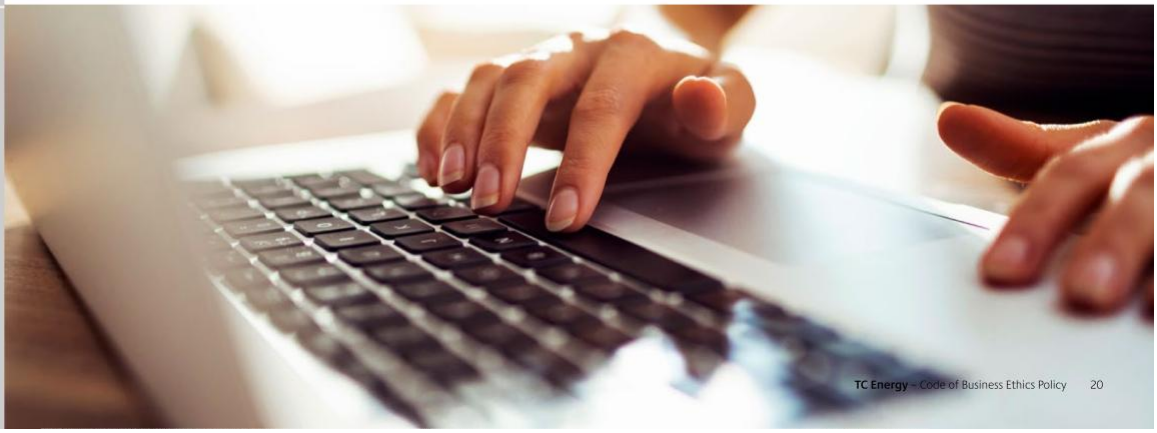
Directors' independence

To maintain their independence and to ensure that no relationships exist that may violate applicable corporate, securities and competition laws, all members of the Board of Directors of TC Energy must have their independence assessed:

- Annually
- In the event of a material change in their respective primary employment status
- When they wish to join another board of directors, whether private or public

All candidates to TC Energy's Board of Directors must declare to the Corporate Secretarial group any material interest that they may have in a contract or transaction.

All members of the TC Energy Board of Directors who have any material interest in a contract or transaction must recuse themselves from related deliberations and approval.



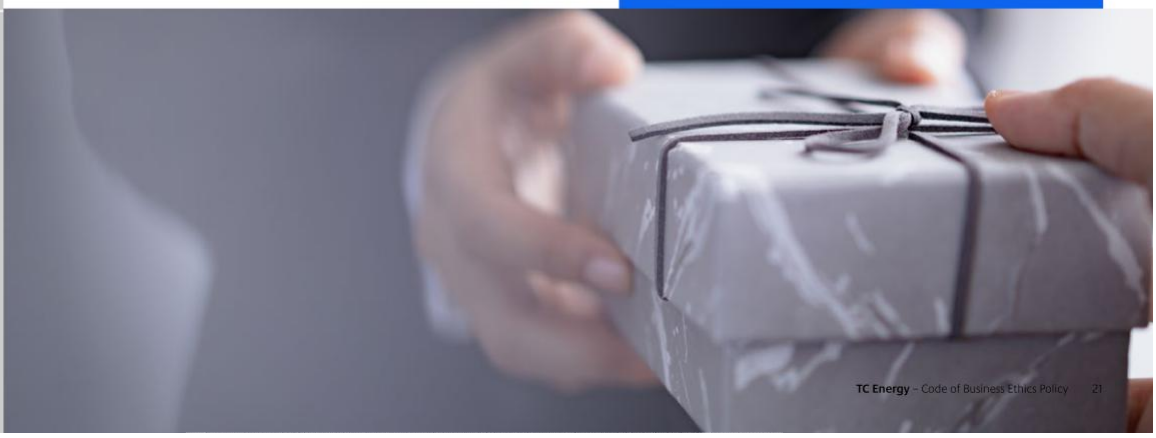
GIFTS, INVITATIONS AND ENTERTAINMENT

Local customs with respect to providing gifts and other benefits can change depending on where we are doing business; however, these local customs must never compromise, or appear to compromise, our ability to act legally, ethically and objectively.

While giving gifts can help to build and maintain strong business relationships, they can also cloud one's judgement or be seen to improperly influence decisions depending on the nature and context of the gift.

We must always be prudent in offering gifts, entertainment or anything of value to anyone or any organization that is a competitor, or that TC Energy does or seeks to do business with, or that TC Energy requires consent or approval from (e.g., a government authority).

Corruption in business and government prevents fair and open competition based on merit and it can have a negative impact for both the Company and the individual. To mitigate these negative impacts, we must all comply with TC Energy's Avoiding Bribery and Corruption Policy, Gift, Meals, Entertainment and Travel for Government Officials Standard, and Gifts and Entertainment Policy.



Accepting gifts, invitations and entertainment from suppliers

Accepting gifts or invitations from suppliers or potential suppliers can affect the way TC Energy is perceived and can run counter to our business objectives and values. We all have an obligation to conduct ourselves in a fair and impartial fashion in all business dealings with the supplier community.

Careful consideration must be taken when a supplier extends an invitation to a social event or offers a gift. Please see the Gifts and Entertainment Policy for more information.

Avoiding Bribery and Corruption Policy

Gifts and Entertainment Policy

Gift, Meals, Entertainment and Travel for Government Officials Standard

QUESTION: *I have been invited by a supplier to attend the rodeo at the Calgary Stampede. Can I accept the invitation and attend the event?*

ANSWER: *All Personnel must ensure they are acting in a manner which is fair and impartial to our supplier community and which does not create a real or perceived conflict of interest with those with whom we do business. As such, since this invitation would fall outside acceptable thresholds for gifts and entertainment, attendance at this event would only be acceptable if prior written approval is obtained from your Vice-President or Senior Vice-President.*

QUESTION: *I sometimes receive items such as coffee mugs and pens from a company that I have a relationship with and which is a supplier to TC Energy. Am I able to accept these items?*

ANSWER: *Employees may accept occasional promotional gifts (such as pens, coffee mugs, calendars) as a customary business courtesy, provided that the gift does not exceed a value of CAD $150/ USD $150/ MXN $1000 per instance or total more than CAD $300/ USD $300/ MXN $2000 in aggregate for the calendar year. All dollar amounts for occasional promotional gifts are in local currency where they are being accepted.*

QUESTION: *One of our existing auto leasing suppliers has invited me to attend their annual product roll-out, which will be held in Las Vegas. It is a big event that all customers are invited to. The supplier has offered to pay for all flights and accommodation, in addition to the meals that will be provided as part of the event. The supplier's contract is not currently up for renewal, and I am not the person responsible for making the decision whether to renew. Can I attend?*

ANSWER: *Since we have an existing business relationship with the supplier and the Company is not currently involved in any renewal or other negotiations, and since the event is a business-related event attended by many customers as well as supplier representatives, you may attend with the approval of your Vice-President or Senior Vice-President. However, given the location of the event, the business benefit to TC Energy should be carefully considered and discussed with your leader. Additionally, since the value of the event is significant, the supplier's payment for flights and accommodation could create a perception of conflict and/or an obligation on the part of TC Energy. As a result, flights and accommodation should be paid for by TC Energy. You may accept the meals provided by the supplier as part of the event.*

ENGAGING GOVERNMENT OFFICIALS

Engaging with Government Officials is an important part of TC Energy's business, and during those engagements, expenses for Government Officials may be incurred. You should never provide Government Officials with bribes, payments, kickbacks, gifts or anything else of value for the purpose of improperly influencing their actions or decisions in TC Energy's favour. These benefits can include entertainment, private parties, charitable contributions or employment opportunities.

Even if there is no intent to influence, you should not provide a payment or benefit to any third party if it could appear to be improper.

- **Avoiding Bribery and Corruption Policy**
- **Gifts and Entertainment Policy**
- **Community Investment Standard**
- **Gift, Meals, Entertainment and Travel for Government Officials Standard**

We are prohibited from offering, paying, promising or authorizing a compensation, payment or benefit to any Government Official, directly or indirectly, to secure any contract, concession or other improper advantage for TC Energy. Such action is prohibited even if the intent is not to influence a Government Official(s), as it could appear to be improper.

With the exception of Mexico, many anti-corruption laws allow reasonable gifts or entertainment for Government Officials in limited circumstances. Only gifts, meals, and entertainment that are reasonable, do not influence business decisions and are not otherwise prohibited may be offered. All gifts, meals or entertainment must be provided in accordance with local laws and regulations, be appropriately recorded in TC Energy's books and records, and follow the appropriate approval processes and thresholds as set out in TC Energy's Gift, Meals, Entertainment and Travel for Government Officials Standard.



INTERNATIONAL TRADE

When engaging in international business and procuring products from the global marketplace, TC Energy complies with all applicable international trade laws, as well as all customs and taxation requirements. International trade laws prohibit or restrict trade with certain countries that are subject to embargoes or sanctions, as well as with certain individuals and organizations (e.g., entities that have ties to actual or suspected terrorists or drug traffickers). These laws also prohibit or restrict imports and exports of certain types of goods, information and technologies and often impose stringent reporting obligations.

Customs and Trade Policy

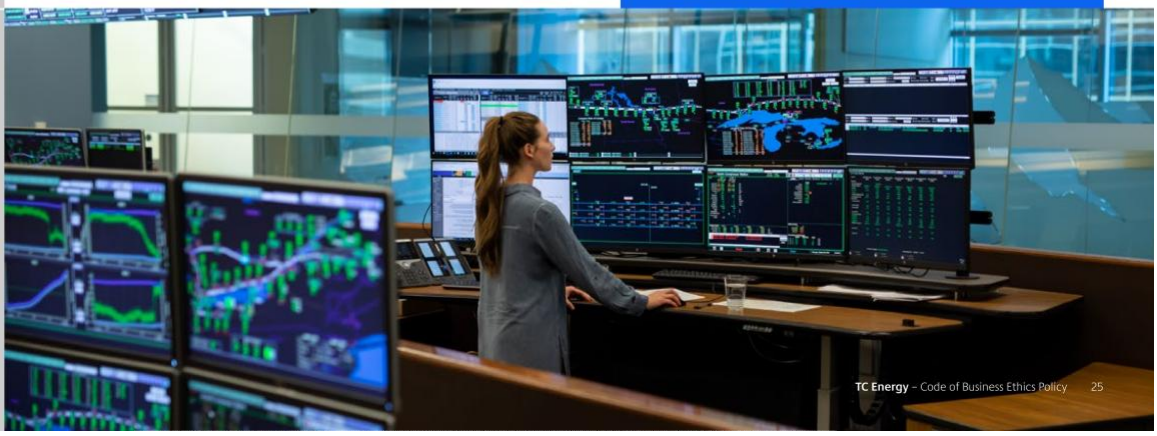
Prior to engaging in any transaction, you must ensure:

- **that it is legally permitted**
- **that all applicable licensing requirements and reporting and customs obligations are met**

And consider:

- **the types and use of the goods, information or technology**
- **The counterparty with which you are dealing**
- **The country in which the counterparty is located**

Even if TC Energy does not have ownership of a product we have purchased when it crosses a border (e.g., because we take ownership, or title, on delivery), we may nevertheless be responsible for import and/or export compliance based on certain terms of the purchase contract. It is important to ensure the contract does not contain terms that result in TC Energy inadvertently taking on these obligations.



INSIDER TRADING

We engage only in transactions that have a legitimate business purpose, and we do not interfere with the normal functioning of the markets in which we operate and transact. We also report transactions in accordance with all legal requirements.

Through the course of your work with TC Energy, you may have access to non-public information regarding TC Energy, our customers, Contractors and other business partners.

You must always maintain the confidentiality of any non-public information encountered through the course of business with TC Energy. To the extent non-public information that you are aware of could be material to a decision to buy or sell shares in TC Energy or another company:

- You and your immediate family members must not trade TC Energy shares or other securities based on that information.
- You must not share material non-public information with another person, except as necessary in the course of business, as outlined in the Public Disclosure Policy.

Trading Policy

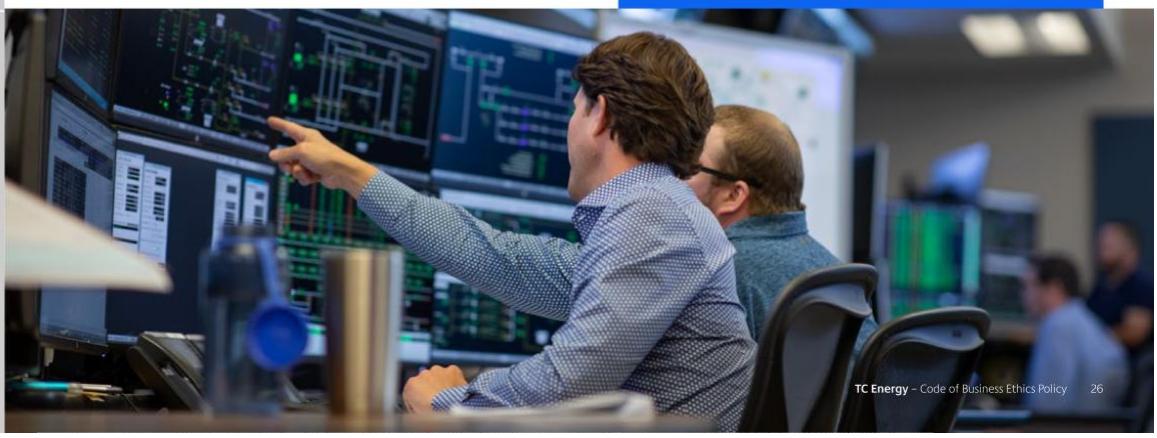
Public Disclosure Policy

We conduct business in a way that promotes a fair, efficient and openly competitive operation of markets we participate in and which complies with market manipulation laws.

QUESTION: *I own units of a mutual fund that invests in shares of one of our suppliers. Is that a problem?*

ANSWER: *Your ownership of mutual fund units is likely not a problem. If your investment in the supplier is through a mutual fund, you would need to ensure that you do not own more than one per cent of the stock of the supplier; however, because of the indirect nature of the investment, it is also less of a concern than if you owned the shares directly.*

Insider trading is a serious offence and can have significant reputational and legal impacts. For Securities and Insider trading inquiries contact Corporate Secretarial Filing Desk.



COMPLYING WITH REGULATORY REQUIREMENTS

TC Energy is committed to meeting our obligations under all regulations and tariffs.

As a regulated company, TC Energy is subject to many regulatory requirements, including those of the Canada Energy Regulator (CER), the Federal Energy Regulatory Commission (FERC), the North American Energy Reliability Corporation (NERC), and the Comisión Nacional de Hidrocarburos, among others. In addition, TC Energy's transmission providers are subject to tariffs that we must comply with.

Although it is impossible to list all of these requirements here, you must ensure you are familiar with the specific requirements applicable to you in your job. These can include reporting requirements and compliance with technical or other standards.

To the extent the requirements of more than one jurisdiction apply, you must comply with the highest of the various standards.



INTER-AFFILIATE INTERACTIONS

As a transmission provider, TC Energy is subject to the Canadian Gas Pipelines Code of Conduct (Code) in Canada, the FERC Standards of Conduct (SOC) in the U.S., and the TC Energía Code of Conduct in Mexico (Inter-Affiliate Codes/Standards of Conduct). These Inter- Affiliate Codes/Standards of Conduct are intended to ensure that our non-regulated affiliates do not receive an unfair advantage over other customers, whether as a result of discriminatory treatment or the improper sharing of information, Personnel or resources. The Inter-Affiliate Codes/Standards of Conduct also prohibit cross-subsidization at the expense of our transmission customers.

In order to ensure compliance with the Inter-Affiliate Codes/Standards of Conduct, you must observe the following rules in your day-to-day activities:

All customers must be treated equally

Regulated transmission providers cannot give undue preference to any customer, whether affiliated with a TC Energy entity or not.

Independent functioning

Regulated Personnel must function independently of non-regulated Personnel (e.g., they cannot perform the same jobs).

No conduit of information

Regulated and shared Personnel must not share, or act as a conduit for the sharing of regulated information* with non-regulated Personnel.

Pay fair share

Non-regulated entities must pay their fair share of any costs incurred by our regulated transmission providers, so as not to burden our transmission customers with costs our non-regulated entities benefit from.

Reporting violations

Any violations of the Inter-Affiliate Codes/Standards of Conduct must be reported to the Corporate Compliance department, since TC Energy may be legally required to either publicly post such information on its web site or report it to our regulators.

**Regulated information (which may not be shared with non-regulated Personnel or affiliates) includes commercial, financial, strategic, planning, operational and customer information of our transmission providers.*

TC Energy's Inter-affiliate Codes/Standards of Conduct



COMPETING FAIRLY

A competitive marketplace in the energy and transmission services that TC Energy provides helps ensure fair prices and customer choice and, in turn, results in the industry as a whole providing more effective and better service. We believe in vigorous, fair competition and comply with all laws designed to protect the ability of companies to compete freely.

You should never enter into agreements to:

- Fix prices
- Decrease capacity or volume available to customers
- Allocate customers or markets among competitors
- Boycott certain customers or Contractors

You need to be very careful whenever you have contact with competitors (whether in trade association meetings, at conferences, through participation in benchmarking groups or in negotiating or otherwise dealing with actual or potential joint venture partners who are also TC Energy competitors) to avoid sharing competitively sensitive information. You must never enter into an agreement to reduce competition, or that is likely to have that effect.

QUESTION: *While at a trade association meeting recently, a few competitors I was sitting with at dinner started talking about their pricing. I knew it wasn't appropriate, so I didn't say anything. Did I do the right thing?*

ANSWER: *While you were right not to participate in the discussion, when in such a situation, it's a good idea to take the further step of making clear to everyone that the discussion is inappropriate and that you will not participate. If the inappropriate discussion continues, you should excuse yourself from the situation. You should also document what happened and report the matter. This will help to protect you and TC Energy in case anyone ever points to the fact that you were part of a group in which an inappropriate discussion took place.*



ACCOUNTING, FINANCIAL REPORTING AND FRAUD PREVENTION

TC Energy ensures that our accounting, financial records and reporting are fair, accurate, understandable and complete, and we do not falsify financial documents or records, or misstate or misrepresent the nature of costs or expenditures.

You must ensure all transactions that you engage in, or that you approve, whether under a TC Energy contract or as an individual business expense, are true and reported accurately, completely and in compliance with all applicable accounting and legal requirements. You must also follow TC Energy's corporate policies and other requirements respecting the transaction (for example, obtaining of approvals).

You must never engage in "off-the-record" or other transactions or accounts that do not fully and accurately state the nature and amount of specific transactions.

You must also never falsify any invoice, expenditure, time sheet or other document related to Company cost or revenue. Doing so constitutes fraud and may result in appropriate corrective action, up to and including termination of employment or contract.

Avoiding Bribery and Corruption Policy

Business Expense Policy

TC Energy's Business Expense Policy

The Business Expense Policy outlines proper management of low cost and low risk expenses incurred while conducting business on TC Energy's behalf and sets expectations regarding Employee use of the corporate credit card for such expenses.

These expectations include a prohibition on splitting transactions to circumvent credit card limits or incurring costs for other Employees. If there is more than one Employee from the same business unit included in the expense, the most senior Employee present must always incur the expense.



PREVENTING MONEY LAUNDERING AND TERRORIST FINANCING

We expect all our Personnel to be vigilant in ensuring the payments we make and the methods of payment we use are legitimate and legal.

Legal requirements concerning money laundering and terrorist financing are in place to deter criminal and terrorist activities of those with whom we might do business.

To ensure compliance with these legal requirements you must:

- Exercise care before agreeing to do business with a third-party, including ensuring that they were reviewed as part of Supply Chain's qualification process
- Ensure the third-party is legitimate and reputable
- Recognize and report any suspicious payments or transactions

Ignoring the signs that a transaction or payment initiated by a third party is not legitimate can result in TC Energy being found complicit in any illegal activity that may be associated with the transaction, even if the Company did not expressly authorize it or even know about it.

Examples of suspicious payments or transactions include:

- Any request by a third-party to have a payment deposited into a personal account rather than a business account
- Transactions with entities other than those involved in the underlying contract or business deal
- Payments or other transactions involving a country other than that in which the parties to the contract or business deal are located

Payments of cash, unusual financing arrangements, fictitious invoices or other efforts by a third party to conceal the true purpose of a payment or transaction also raise concerns.



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COMMUNICATION

- Being socially responsible
- Being a good ambassador of TC Energy
- Social media and communication with the public
- Public disclosure of information
- Dealing fairly with customers, Contractors and other stakeholders
- Dealing fairly with competitors



BEING SOCIALLY RESPONSIBLE

TC Energy is committed to being a good neighbour and supporting and enhancing the communities in which we live and work.

Some of the most important communities our business impacts are Indigenous communities. We are committed to working with these communities, to develop positive, long-term relationships based on mutual trust and respect, and recognizing their diversity and the importance they place on the land, their culture and their traditional way of life.

In addition to working with Indigenous communities, we also work hard to build and maintain relationships with landowners. We recognize the importance of farming to their communities, and actively support farming-related organizations.

TC Energy understands the importance that community, charitable and similar non-governmental organizations play in making the communities in which we live and work better places. We actively support these organizations and encourage our Personnel to become involved by volunteering and contributing to charitable and other community-based organizations, including during work hours if approved by your leader.

Our Commitment Statement

Indigenous Relations Policy



BEING A GOOD AMBASSADOR OF TC ENERGY

We recognize that we are ambassadors of TC Energy and conduct ourselves in a manner that is respectful and appropriate, and that will not harm TC Energy's reputation.

You must always keep in mind that you are a representative of TC Energy. The things you say and do should reflect the Company's core values. You should not speak publicly on behalf of TC Energy unless authorized to do so. Any posting or statement on an external website, including personal sites or in other media, should be considered a public statement.

Even on your personal time, you must not participate in any illegal or inappropriate statements or activities that could be detrimental to the Company or its reputation.

Public Disclosure Policy

Communications Policy



SOCIAL MEDIA AND COMMUNICATIONS WITH THE PUBLIC

In the age of social media, it is easy to broadly and publicly communicate information. You need to be particularly aware of your obligations and our expectations when it comes to the disclosure of Company information and ensuring it is in accordance with legal and internal requirements.

When sharing information on social media, keep the following requirements in mind:

- Do not speak on behalf of, or giving the impression that you are speaking on behalf of, TC Energy unless you have been authorized to do so
- Never falsely represent yourself
- Do not post anything that reflects negatively on TC Energy and ensure posts are not discriminatory, offensive, or in poor taste
- Share only approved TC Energy content, add value to the conversation, and be accurate
- Do not post pictures of TC Energy's facilities or operations unless you are authorized to do so



PUBLIC DISCLOSURE OF INFORMATION

TC Energy ensures that public statements regarding the Company are provided in a timely manner, are fair, accurate and complete, comply with legal requirements and corporate policies, and preserve and protect our reputation and brand.

TC Energy has prescribed Personnel who are authorized to speak on our behalf. If you receive an inquiry for information or comment, you should direct it to the appropriate Company representative for response.

If you are not sure who the appropriate company representative is to respond, please direct the inquiry to our media line 1-800-608-7859.

Public Disclosure Policy

Communications Policy

Use of company name for personal gain

You must never use the Company's name or purchasing power or your employment status to obtain personal discounts or rebates from Contractors unless those discounts or rebates are available to all Employees.



DEALING FAIRLY WITH CUSTOMERS, CONTRACTORS AND OTHER STAKEHOLDERS

We consider the impact of our actions on stakeholders, rightsholders, the environment and the communities in which we operate. We follow the requirements of our policies, procedures and commitment statements to make sure we act responsibly to protect us, our co-workers, our workplace and assets and the communities we work in. We act as responsible stewards of the environment and manage risk, share knowledge and best practices to ensure continual improvement.

You should never make business decisions on behalf of TC Energy based on personal relationships, unfair bias or the potential for personal gain.

We are fair and honest in our dealings with customers, Contractors and other stakeholders and we honour our obligations and commitments to them.

Treating customers, Contractors and other stakeholders fairly requires that you:

- Enter into business relationships based on merit
- Use objective criteria to evaluate them, such as:
  - Price
  - Quality
  - Service

It also requires that you are honest and forthright when dealing with others (never omitting important facts, manipulating another person or situation, or misrepresenting yourself or TC Energy), and that you honour TC Energy's contractual, regulatory and other commitments.



DEALING FAIRLY WITH COMPETITORS

You must ensure that you use only legitimate means (such as searches of public information) to obtain competitive intelligence.

You must never use deceit or misrepresent yourself to obtain such information, and you should never take advantage of information you receive in error, for example:

- Emails or faxes received in error
- Physical documents left in a meeting room or in a public place or which have been sent to you in error
- Information you overheard



ASSETS AND INFORMATION

- Protecting confidential information
- Protecting personal information
- Managing and maintaining the security of information
- Protecting and respecting intellectual property rights
- Use and protection of TC Energy assets



PROTECTING CONFIDENTIAL INFORMATION

We protect TC Energy's confidential information, and that of our customers, Contractors and other stakeholders, from improper disclosure and use.

We all have access to confidential information. TC Energy confidential information includes all TC Energy non-public information that may be of use to competitors or harmful to TC Energy or its customers, Contractors or other stakeholders, if disclosed.

Confidential information can include:

- Information regarding TC Energy's business, operations, finances, strategies, business plans, or projects
- Proposed mergers, acquisitions and divestitures
- Engineering designs and reports
- Legal proceedings, contracts
- Environmental reports
- Land and lease information
- Technical and economic data
- Marketing information and field notes
- Sketches and photographs
- Electronic information assets (including emails, voicemails, and text messages)
- Computer records or software, specifications, models
- Other information which is or may be either applicable to or related in any way to the assets, business or affairs of TC Energy

Confidential information about TC Energy's projects and operations, such as project delays, costs or outage timing and the resulting system capacity impacts can influence the decisions of participants in the gas market. Such information must be disclosed to all customers and other gas market participants at the same time through our typical communication protocols, such as a bulletin.

Because such information is commercially sensitive and can be used by competitors or others to TC Energy's detriment, it must be protected. You must not disclose such information to anyone who does not need to know the information for legitimate business purposes (including within TC Energy).

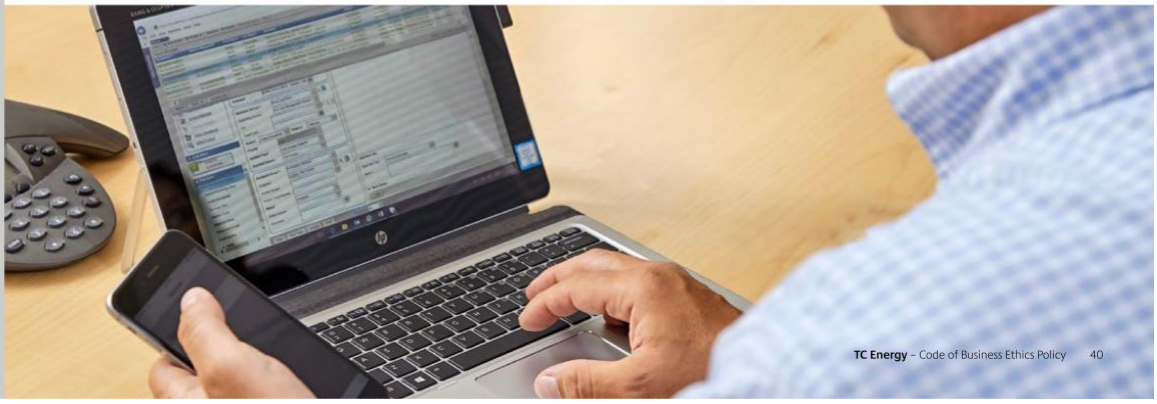
All confidential information should be protected from unauthorized access. When disposing of confidential information, you should do so in a secure manner, which may include shredding of hard copies.

See additional information in the Use and Protection of TC Energy's Assets and the Managing and Maintaining the Security of Information sections.

Information Management Policy

Cybersecurity Policy

Records Retention Schedule



PROTECTING PERSONAL INFORMATION

TC Energy takes seriously the fact that its Employees, Contractors, customers and other stakeholders have entrusted the Company with their personal information.

Some examples of personal information include an individual's name, home address, telephone number, identification numbers (such as an Employee number or social insurance/social security number), financial information, and medical information.

You should never collect, store, access, use, or disclose personal information for an inappropriate purpose or by inappropriate or illegal means. Use of personal information must be limited to the business purposes for which the information was provided. To the extent that you have personal information of any individual as a result of your work with TC Energy, whether the individual is an Employee, Contractor, landowner or a shareholder (to name just a few examples), you may not disclose that personal information to others, nor may you use it for a purpose other than that for which it was collected, either within or outside TC Energy, without the express approval of TC Energy's Privacy Officer or the individual's written consent.

TC Energy is committed to protecting personal information in compliance with all legal requirements and requires that our Contractors share this commitment to information security.

If you are ever unsure if information can be disclosed or used for a new purpose, check with TC Energy's Privacy Office before taking any action.

For more information, please see the Protection of Personal Information Policy.

Protection of Personal Information Policy

You should also protect and safeguard personal information from inappropriate access by keeping it in a locked cabinet, or in a password protected or otherwise restricted folder, memory stick or other similar storage device, if the information is electronic.



MANAGING AND MAINTAINING THE SECURITY OF INFORMATION

Company records are valuable assets of TC Energy and you must ensure appropriate and reasonable efforts are made to manage, protect and preserve these assets.

All of these information assets are important Company records that TC Energy may be required to produce in the event of a legal or regulatory proceeding, audit or investigation. It is important that you manage and retain these assets in accordance with all legal requirements and TC Energy's corporate policies. In particular, you must never destroy an information asset in the event of a legal hold or an actual or pending legal or regulatory proceeding.

Information Management Policy

Cybersecurity Policy

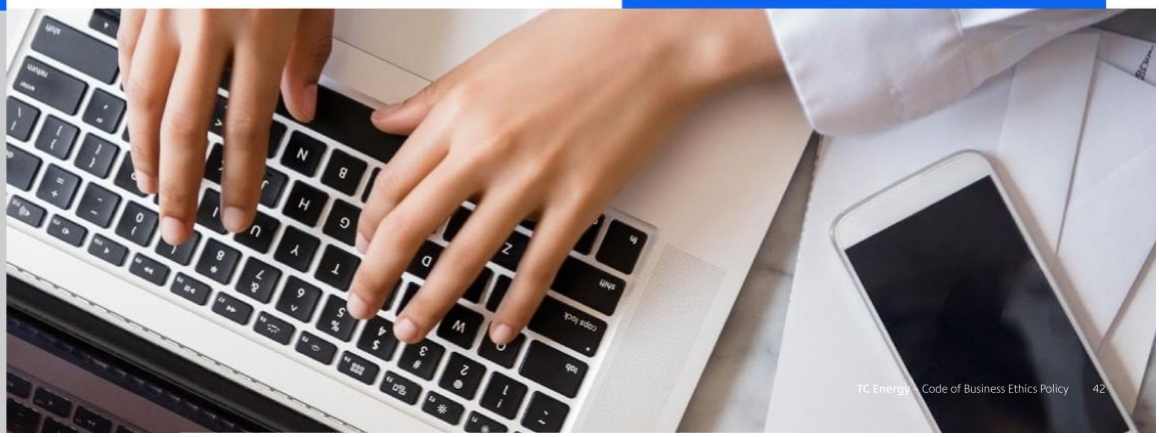
What are information assets?

- Memos
- Emails
- Accounting records
- Invoices and contracts
- Technical drawings
- Recordings of trade-related phone calls
- Records of safety or other incidents
- Marketing literature
- Other similar types of records

What form can an information asset take?

An information asset can take any form or on any media, including:

- Paper
- CD
- DVD
- Voice or video recordings
- Text and instant messages
- Other electronic formats



PROTECTING AND RESPECTING INTELLECTUAL PROPERTY RIGHTS

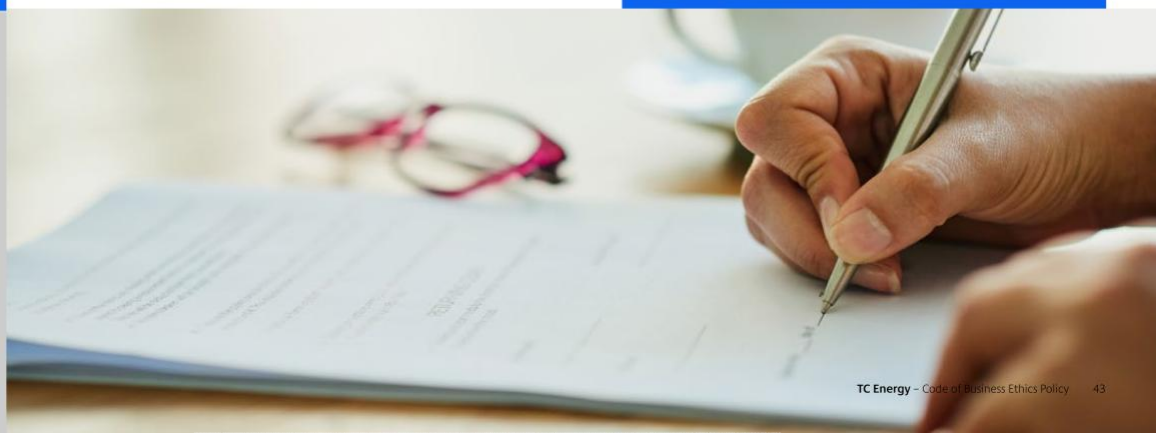
We preserve TC Energy's intellectual property rights and respect and honour those of third parties.

Intellectual property can include trade secrets, which is any information that gives the owner an economic advantage over its competitors and that the owner takes reasonable steps to keep confidential, as well as copyrights, trademarks and patents, and also includes inventions, innovations, discoveries and copyrighted material developed while employed by TC Energy.

We must take steps to protect intellectual property rights. This includes keeping trade secrets confidential, consistently using TC Energy's trademarks solely as authorized, and respecting the intellectual property rights of third parties.

TC Energy respects and honours intellectual property rights by:

- Complying with the terms of license agreements that TC Energy has entered into with Contractors
- Complying with copyright legislation
- Not using improper means to obtain third-party information or trade secrets
- Using confidential third-party information only for the purpose for which it was provided



USE AND PROTECTION OF TC ENERGY'S ASSETS

TC Energy assets that you have access to for the completion of your duties must be protected and only used for legitimate business purposes.

You have an obligation to be a good steward of the assets that TC Energy provides to you in the course of your work and you must protect these assets from loss, theft, damage and misuse.

Additionally, using Company facilities, equipment and/or Company time to work on your personal assets, for personal activities or to store personal assets is not allowed.

Limited personal use of Company assets such as accessing Internet or printing is acceptable provided that it does not interfere with your job duties. TC Energy regularly monitors Company internet use, and individuals should not assume any right of privacy with respect to either their use of or data stored on TC Energy's computer systems. Any misuse of Company assets or services, including inappropriate use of TC Energy's computer equipment and systems, may lead to serious consequences including appropriate corrective action up to and including termination of employment or contract.

Acceptable Use Policy

Corporate Security Policy

QUESTION: *I sometimes use my Company computer to access Facebook or Twitter during my lunch break and I post about my personal life. Is that allowed?*

ANSWER: *Limited personal use of Company assets to access social media during a break is acceptable; however, you need to keep in mind that you are using a Company computer and accessing the Internet through a TC Energy IP address., You must ensure that you do not post content that is inappropriate or could reflect poorly on TC Energy. The Company regularly monitors the use of its equipment and systems and you should not expect your personal use of TC Energy assets to be private. Any inappropriate or offensive use of Company assets by Personnel may result in disciplinary action.*

What are Company assets?

Company assets can include:

- Company time
- Equipment
- Facilities
- Furniture
- Computers
- Telephones
- Supplies
- Tools
- Personal protective equipment
- Corporate credit cards
- Other resources

What can Company assets NOT be used for?

Company assets must not be used for:

- Engaging in hate-based activities
- Downloading illegal material
- Viewing pornography
- Other inappropriate uses

QUESTION: *I send my claims to TC Energy benefits providers and use my TC Energy address to receive trade publications, contact lenses and books for the book club that I started with my coworkers. Is that allowed?*

ANSWER: *Personal shipments and mail must not be sent to your TC Energy address. Personal shipments include:*

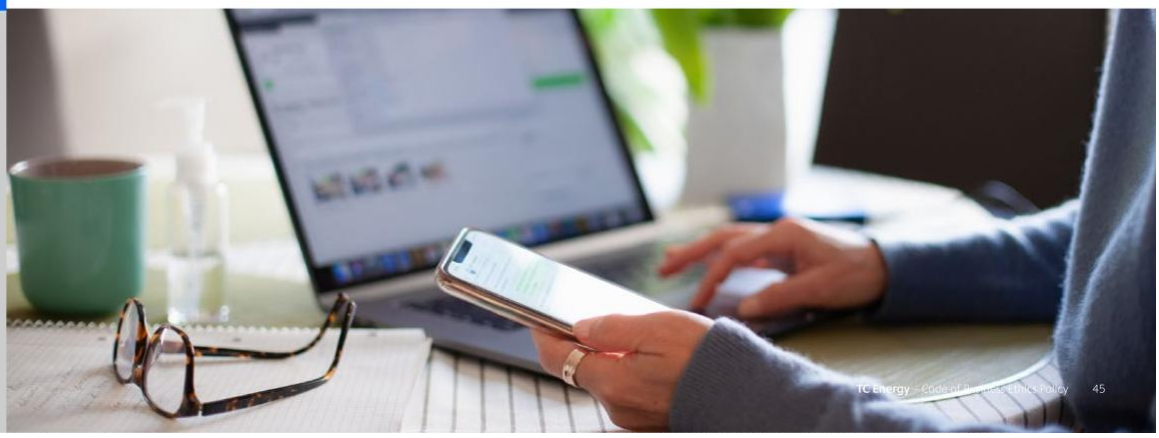
- *Personal online purchases, such as electronics, clothing, footwear, hygiene/beauty products, food, contact lenses/glasses, book of the month/wine of the month or any other shipments for interest group meetings, including those created by and for Personnel*
- *Personal magazine and newspaper subscriptions, except for business correspondence, trade publications and vendor catalogues*
- *Gifts from friends and family, except for flower deliveries and gifts from Contractors which must comply with all applicable TC Energy corporate policies*

AS an exception to this rule, Personnel may send their claims to TC Energy benefits providers (e.g., Sun Life Financial and MetLife) or send personal mail with the appropriate postage affixed through Company mailrooms.

QUESTION: *I live in a very small condominium and keep my bike chained to an outside bike rack except for winters, when I store it in a paid facility. My co-worker told me about an empty shed in one of the Company's field sites near my condo. Would it be acceptable for me to keep my bike in the Company's shed for winter?*

ANSWER: *Storing your bike in the Company's shed for the winter is not acceptable. Storing personal property that is not required during work hours, such as motorized and nonmotorized vehicles, including but not limited to bicycles, motorcycles, RVs and boats, on the Company premises is generally prohibited. There are two exceptions:*

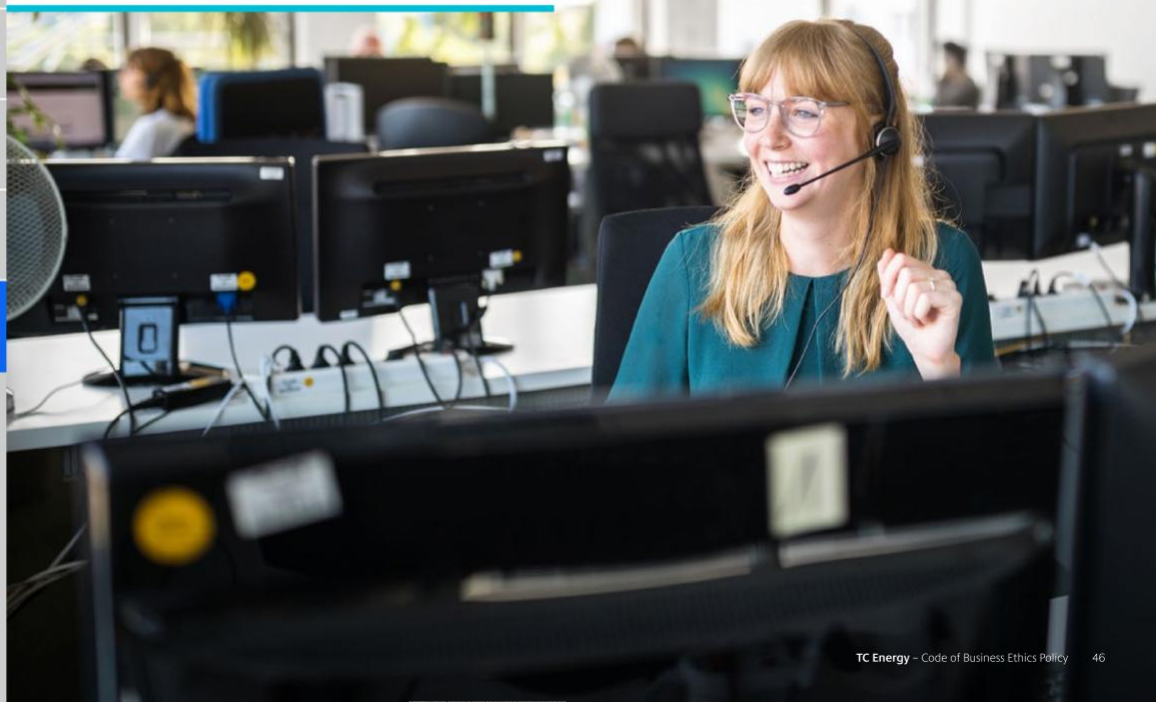
- *Subject to the site management's approval, Personnel who commute to remote worksites to perform their job duties may park their personal vehicle used to reach the site on the Company premises for the duration of their work shift*
- *Parking spaces on the Company premises that are either designated or paid for by Personnel may be used to park a personal vehicle, subject to notices to vacate the parking space for seasonal cleaning, maintenance or repairs.*



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HAVE A QUESTION? WE'RE HERE TO HELP

+ Your responsibility and non-retaliation
+ Asking questions and reporting concerns



TC Energy

YOUR RESPONSIBILITY

Personnel must follow all applicable provisions and the spirit and intent of this corporate governance document and support others in doing so. Personnel must promptly report any suspected or actual violation of this corporate governance document through available channels so that TC Energy can investigate and address it appropriately. Personnel who violate this corporate governance document or knowingly permit others under their supervision to violate it, may be subject to appropriate corrective action, up to and including termination of employment or contract, as applicable, in accordance with the Company's corporate governance documents, employment practices, contracts, collective bargaining agreements and processes.

INTERPRETATION AND ADMINISTRATION

The Company has sole discretion to interpret, administer and apply this corporate governance document and to change it at any time to address new or changed legal requirements or business circumstances.

NON-RETALIATION

TC Energy supports and encourages Employees and Contractors to report suspected violations of corporate governance documents, applicable laws, regulations, and authorizations, as well as hazards, potential hazards, incidents involving health and safety or the environment, and near hits. Such reports can be made through available channels. TC Energy takes every report seriously and investigates it to identify facts and, when warranted, makes improvements to our corporate governance documents and practices. All Employees and Contractors making reports in good faith will be protected from retaliation, and all Employees and Contractors must report if they or someone they know is being or has been retaliated against for reporting. Good Faith Reporting will not protect Employees and Contractors who make intentionally false or malicious reports, or who seek to exempt their own negligence or willful misconduct by the act of making a report.



GLOSSARY

Advisory Relationship means a relationship where one provides advice, counsel, suggestions, recommendations, intelligence, guidance or any other similar types of information or opinion.

Contingent Workforce Contractor (CWC) means an individual who:

- is employed by a third party to work on behalf of TC Energy;
- uses TC Energy's assets (e.g., workstation, email, phone) and corporate services;
- is compensated on an hourly or daily rate basis (Canada and the U.S.) and monthly (Mexico); and
- works under the direction of a TC Energy leader.

Contractor means a third party hired by TC Energy to perform services for or supply equipment, materials, or goods to the Company. Contractors include, without limitation, Contingent Workforce Contractors and Excluded Contractors.

Employee means full-time, part-time, temporary and student employees of TC Energy.

Excluded Contractor means a third party or individual employed by a third party who:

- delivers services, equipment, materials, or goods to the Company using their own tools and assets (e.g., work station, laptop, email, phone, PPE, vehicle);
- does not increase TC Energy corporate headcount and overhead costs;
- does not use TC Energy's assets and corporate services; and
- direct their own work or receives direction from their employer.

Family Relationship means relatedness or connection by blood, marriage or adoption and includes, but is not limited to:

- a marriage/common law spouse;
- parent and grandparent;
- child and grandchild;
- sibling;
- aunt and uncle;
- niece and nephew;
- first cousin; and
- any "step", "common law", or "in law" variations of the above relationships.

Good Faith Reporting means an open, honest, fair and reasonable reporting without malice or ulterior motive.

Government Officials means any appointed, elected, or honorary official or any employee of a government, of a government owned or controlled company, or of a public or international organization. This definition encompasses officials in all branches and at all levels of government: federal, state/provincial or local. This definition also includes political parties and party officials and candidates for political office. Indigenous officials may also be considered Government Officials. A person does not cease to be a Government Official by claiming to act in a private capacity or by the fact that he/she serves without compensation.

Examples of Government Officials relevant to TC Energy's business include:

- government ministers and their staff;
- members of legislative bodies or other elected officials;
- officials or employees of government departments;
- employees of regulatory agencies;
- judges and judicial officials;
- employees of state-owned oil companies, or other government-owned or controlled corporations;
- customs, immigration, tax, and police personnel;
- Indigenous government officials; and
- employees of public international organizations, such as the United Nations or World Bank.

Intimate Relationship means any romantic and/or dating and/or sexual relationship, including casual encounters.

Personal Relationship means all Family Relationships and Intimate Relationships and any other personal relationship that is sufficiently close to create a real or perceived conflict of interest.

Personnel means full-time, part-time and temporary Employees and Contingent Workforce Contractors of TC Energy.

TC Energy or the **Company** means TC Energy Corporation and its wholly-owned subsidiaries and/or operated entities.

MAKING THE RIGHT CHOICES — DOING THE RIGHT THING



TC Energy

July 2023