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, 2021

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 Section 15(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, 2021, 980,815,927 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;
10,000,000 Cumulative Redeemable First Preferred Shares, Series 11; and
40,000,000 Cumulative Redeemable First Preferred Shares, Series 15
of TC Energy Corporation were issued and outstanding.

At December 31, 2021, 940,063,806 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. ☒

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	333-151781
F-10	333-161929
F-10	333-208585
F-10	333-250988
F-10	333-252123
F-10	333-253333
F-10	333-261533

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 ANNUAL 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 2021 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 Annual Financial Statements

For audited consolidated financial statements, including the auditors' report, see pages 121 through 202 of the TC Energy 2021 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 120 of the TC Energy 2021 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 121 of the TC Energy 2021 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 105 of the TC Energy 2021 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 and Mr. Thierry Vandal have been designated audit committee financial experts and are 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 and Mr. Vandal as audit committee financial experts does not make Ms. Power or Mr. Vandal "experts" for any purpose, impose any duties, obligations or liability on Ms. Power or Mr. Vandal that are 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 2021, the Code was updated with amendments for avoiding conflicts of interest; providing and receiving gifts, entertainment and invitations; accounting, financial reporting and fraud prevention; social media and communications; weapons in the workplace; values and expectations more prominently highlighted; as well as changes throughout to update the branding, tone, and readability of the document.

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 2021 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 38 of the TC Energy 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 29 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 90 of the TC Energy 2021 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 each Audit committee as of February 14, 2022 (unless otherwise indicated) are:

Chair:	**U. Power**
Members:	**M.R. Culbert**
	W.D. Johnson[1]
	S.C. Jones
	R. Limbacher
	D.M.G. Stewart[2]
	T. Vandal

[1] Mr. Johnson was appointed as a member of the Audit Committee on June 14, 2021.

[2] Mr. Stewart was appointed as a member of the Audit Committee on May 7, 2021.

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, including portfolio management
- expected dividend growth
- expected access to and cost of capital
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures, contractual obligations, commitments and contingent liabilities
- expected regulatory processes and outcomes
- statements related to our greenhouse gas emissions reduction goals
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- the expected impact of future tax and accounting changes
- expected industry, market and economic conditions
- the expected impact of COVID-19.

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 and energy transition
- regulatory decisions and outcomes
- planned and unplanned outages and the use of our pipeline, 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
- inflation rates and commodity prices
- interest, tax and foreign exchange rates
- nature and scope of hedging
- expected impact of COVID-19.

Risks and uncertainties

- realization of expected benefits from acquisitions and divestitures
- our ability to successfully implement our strategic priorities and whether they will yield the expected benefits
- our ability to implement a capital allocation strategy aligned with maximizing shareholder value
- the operating performance of our pipeline, power and storage assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the amount of capacity payments and revenues from our power generation assets due to plant availability
- production levels within supply basins
- construction and completion of capital projects
- cost and availability of labour, equipment and materials
- the 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 and COVID-19
- our ability to realize the value of tangible assets and contractual recoveries, including those specific to the Keystone XL pipeline project
- competition in the businesses in which we operate
- unexpected or unusual weather
- acts of civil disobedience
- cyber security and technological developments
- environmental, social and governance 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, including COVID-19 and the unexpected 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, 2021.
13.2	Management's discussion and analysis (included on pages 9 through 120 of the TC Energy Corporation 2021 Management's discussion and analysis and audited consolidated financial statements to shareholders).
13.3	2021 Audited consolidated financial statements (included on pages 121 through 202 of the TC Energy Corporation 2021 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, 2021.
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.
99.1	A copy of 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 14, 2021, 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 15, 2022

TC Energy Corporation

2021 Annual information form

February 14, 2022

Contents

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, 2021 (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 14, 2022 (MD&A) are incorporated by reference into this AIF as stated below. The MD&A can be found on SEDAR (www.sedar.com) under TC Energy's profile.

Financial information is presented in accordance with United States (U.S.) generally accepted accounting principles (GAAP). We use certain financial measures that do not have any standardized meaning under GAAP and therefore they may not be comparable to similar measures presented by other entities. Refer to the *About this document – Non-GAAP measures* section of the MD&A for more information about the non-GAAP measures we use and a reconciliation to their GAAP equivalents, which section of the MD&A is incorporated by reference herein.

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, including portfolio management
- expected dividend growth
- expected access to and cost of capital
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures, contractual obligations, commitments and contingent liabilities
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- the expected impact of future tax and accounting changes
- expected industry, market and economic conditions
- the expected impact of COVID-19.

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 and energy transition
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- our ability to realize the value of tangible assets and contractual recoveries, including those specific to the Keystone XL pipeline project
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- unexpected or unusual weather
- acts of civil disobedience
- cyber security and technological developments
- ESG 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, including COVID-19 and the unexpected 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.

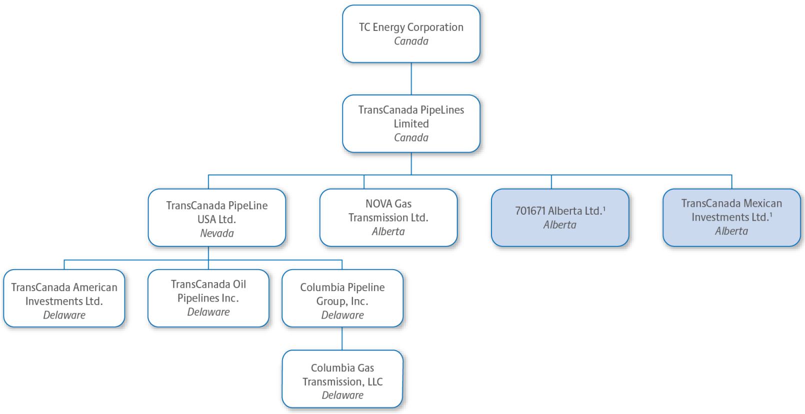
TC Energy Corporation

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. 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.

General development of the business

We operate in three core businesses – Natural Gas Pipelines, Liquids Pipelines and Power and Storage. 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 Storage. 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.

Natural Gas Pipelines and Liquids Pipelines are principally comprised of our respective natural gas and liquids pipelines in Canada, the U.S. and Mexico, as well as our regulated natural gas storage operations in the U.S.

Power and Storage includes our power operations and our unregulated natural gas storage business in Canada.

Summarized below are significant developments that have occurred in our Natural Gas Pipelines, Liquids Pipelines and Power and Storage 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 2022. Further information about developments in our business, including changes that we expect will occur in 2022, can be found in the *Natural Gas Pipelines Business, Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines* and *Power and Storage* sections of the MD&A, which sections of the MD&A are incorporated by reference herein.

NATURAL GAS PIPELINES

Developments in the Canadian Natural Gas Pipelines Segment

Date	Description of development
CANADIAN REGULATED PIPELINES	
NGTL System - 2021 and 2022 Expansion Programs	
2019	We pursued applications to the CER (formerly the NEB, see the *Business of TC Energy - Regulation of Natural Gas Pipelines and Liquids Pipelines* section below) on two expansion programs within our natural gas gathering and transportation system for the WCSB (NGTL System): (1) the NGTL System 2021 Expansion Program (2021 Expansion Program); and (2) the NGTL System 2022 Expansion Program (2022 Expansion Program).
2020	The 2021 Expansion Program application was concluded in fourth quarter 2020. We received regulatory approval of the 2021 Expansion Program and began progressing construction activities.
2021	Construction activities on the 2021 Expansion Program continue to progress with approximately $0.9 billion in facilities placed in service to date. The program, with a total estimated capital cost of $3.2 billion, consists of 345 km (217 miles) of new pipeline, three compressor units and associated facilities. Final completion of the program is expected in second quarter 2022. In 2021, we received regulatory approval for the 2022 Expansion Program. With an estimated capital cost of $1.2 billion, the 2022 Expansion Program consists of approximately 166 km (103 miles) of new pipeline, one new compressor unit and associated facilities and will provide incremental capacity of approximately 773 TJ/d (722 MMcf/d) to meet firm-receipt and intra-basin delivery requirements with eight-year terms. Construction activities began in September 2021 with anticipated in-service dates commencing in fourth quarter 2022.
2023 NGTL System Intra-Basin Expansion	
2020	In 2020, we approved the NGTL System Intra-Basin Expansion, subject to required regulatory approval, for a contracted incremental intra-basin delivery capacity of 331 TJ/d (309 MMcf/d) for 15-year terms at an estimated capital cost of $0.9 billion.
2021	In 2021, we received regulatory approval to construct and operate the NGTL System Intra-Basin Expansion Program, consisting 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. Based on the outcome of the 2021 Capacity Optimization Open Season, changes in expected supply have reduced the scope of the program which now has an estimated capital cost of $0.6 billion. The NGTL System Intra-Basin Expansion is expected to be placed in service commencing in 2023.
NGTL System/Foothills West Path Delivery Program	
2019	In 2019, we approved the West Path Delivery Program, an expansion of the NGTL System and Foothills pipeline system for contracted incremental export capacity on the Gas Transmission Northwest pipeline system (GTN System), subject to regulatory approval.
2020	We filed applications to construct and operate certain of the associated facilities with an estimated capital cost of $0.8 billion and received CER approval to construct and operate $0.2 billion of such facilities.
2021	The Canadian portion of the expansion program has an estimated capital cost of $1.2 billion as a result of refined cost estimates and increased construction costs and consists of approximately 107 km (66 miles) of pipeline and associated facilities with in-service dates in fourth quarter 2022 and fourth quarter 2023. The program is underpinned by approximately 275 TJ/d (258 MMcf/d) of new firm-service contracts with terms that exceed 30 years. Regulatory approvals to construct and operate $0.4 billion of the facilities have been received and applications for the remaining facilities have been submitted with approvals anticipated in first and fourth quarter 2022.
NGTL System - North Montney Mainline (NMML)	
2019	In March 2019, the NGTL System Rate Design and Services Application was filed with the NEB which addressed rate design, terms and conditions of service for the NGTL System and a tolling methodology for the NMML.
2020	In March 2020, the CER issued a decision approving all elements of the NGTL System Rate Design and Services Application as filed. In January 2020, the $1.1 billion Aitken Creek section of the North Montney project was placed into service with the final section of the project, Kahta South, placed into service in May 2020. All compressor stations, pipeline sections and 11 of the 13 meter stations are complete and operational.
2021	In 2021, the final two meter stations were placed in service.

Date	Description of development
NGTL System - Revenue Requirement Settlements	
2019	During 2019, the NGTL System operated under the 2018-2019 Revenue Requirement Settlement (2018-2019 Settlement), which was approved by the NEB in June 2018. The 2018-2019 Settlement, which fixed ROE at 10.1 per cent on 40 per cent deemed common equity and increased the composite depreciation rate from 3.18 per cent to 3.45 per cent, expired on December 31, 2019.
2020	Following the expiration of the 2018-2019 Settlement, the NGTL System operated under interim tolls until, in August 2020, the CER approved the NGTL System's 2020-2024 Revenue Requirement Settlement Application. Effective January 1, 2020, the NGTL System is operating under the 2020-2024 Revenue Requirement Settlement (2020-2024 Settlement) which includes an 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.
Canadian Mainline - Long-Term Fixed-Price Services	
2019	In January 2019, we filed an application with the NEB for approval of 670 TJ/d (625 MMcf/d) of new 15-year natural gas transportation contracts to provide customers with transportation services from the WCSB on the Canadian Mainline. This application was approved in May 2019 resulting in associated enhancements to the Canadian Mainline at a capital cost of $104 million.
Canadian Mainline Settlement	
2019 - 2020	In March 2019, the NEB approved the tolls as filed in the January 2019 compliance filing related to the Canadian Mainline toll review, which was completed by the NEB in December 2018. In 2019 and 2020, the Canadian Mainline operated under the terms of the 2015-2030 Tolls Application, which was approved in 2014 and expired on December 31, 2020. The terms of the 2015-2030 Tolls Application included an ROE of 10.1 per cent on deemed common equity of 40 per cent.
2020	In April 2020, the CER approved a six-year unanimously supported negotiated settlement (2021-2026 Mainline Settlement) between the Canadian Mainline, its customers and other stakeholders.
2021	Effective January 1, 2021, 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.
LNG PIPELINE PROJECTS	
Coastal GasLink	
2019	In response to a previous legal proceeding challenging the BCEAO's jurisdiction over the pipeline project in July 2019, the NEB issued its decision affirming provincial jurisdiction for Coastal GasLink. In addition, in December 2019, the B.C. Supreme Court granted the project an interlocutory injunction confirming the legal right to pursue its permitted and authorized activities through to completion.
2020	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 pipeline. Effective with closing, we commenced recognition of development fee revenue earned during the construction of the pipeline for management and financial services provided and began accounting for our remaining 35 per cent investment using equity accounting. In conjunction with the equity sale, Coastal GasLink LP entered into project-level credit facilities which will fund the majority of the construction costs of Coastal GasLink. Due to COVID-19, in December 2020, the British Columbia Provincial Health Officer issued an order restricting the number of workers on site for industrial projects in the Northern Health Authority region of British Columbia. Industrial projects must submit restart plans to the Provincial Health Officer detailing steps to resume site work. Coastal GasLink LP has worked with the provincial health authorities to safely resume construction activities in accordance with the objectives and timelines defined in the order.

Date	Description of development
2021	The project is currently more than 59 per cent complete. The entire route has been cleared, grading is more than 70 per cent complete and more than 240 km (149 miles) of pipeline has been installed, with reclamation activities underway in many areas. 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 from late December 2020 until mid-April 2021, we continue to expect project costs to increase significantly along with a delay to project completion compared to the original project cost and schedule. Coastal GasLink has sought to mitigate cost increases and schedule delays and will continue to do so. Coastal GasLink is in dispute with LNG Canada with respect to the recognition of certain costs and the impacts on schedule; however, the parties are in active and constructive discussions toward a resolution of this matter. We do not expect any suspension of construction activities while discussions continue. The ultimate level of debt financing and the amounts to be contributed as equity by Coastal GasLink LP partners, including us, will be determined by the substance of a resolution with LNG Canada. During this time, in addition to using funds from its $6.8 billion project-level credit facility and the recovery of construction carrying costs from LNG Canada, construction is also being funded in part by a subordinated demand revolving facility with TC Energy which has a current capacity of $500 million and provides the project with additional short-term funding and financial flexibility. At December 31, 2021, $1 million was outstanding on this revolving facility. In fourth quarter 2021, as a further 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. This financing will be provided through a combination of interest-bearing loans and loans that are subject to a return to TC Energy under certain conditions at the time the final cost of the project is determined. At December 31, 2021, $238 million was outstanding on these loans.

Developments in the U.S. Natural Gas Pipelines Segment

Date	Description of development
U.S. NATURAL GAS PIPELINES - COLUMBIA PIPELINE GROUP	
Sale of Columbia Midstream Assets	
2019	In August 2019, we finalized the sale of certain Columbia Midstream assets to UGI Energy Services, LLC for proceeds of approximately US$1.3 billion, before post-closing adjustments. The sale resulted in a pre-tax gain of $21 million ($152 million after-tax loss), which included the release of $595 million of Columbia goodwill allocated to these assets that is not deductible for income tax purposes. This sale did not include any interest in Columbia Energy Ventures Company, which is our minerals business in the Appalachian basin.
Columbia Gas Transmission, LLC (Columbia Gas) - Mountaineer XPress	
2019	The Mountaineer XPress project was phased into service over first quarter 2019. The project was designed to transport supply from the Marcellus and Utica shale plays to points along the system and to the Leach interconnect with Columbia Gulf. The project consists of 275 km (171 miles) of 36-inch greenfield pipeline, 10 km (six miles) of 24-inch lateral pipeline, 0.6 km (0.4 miles) of 30-inch replacement pipeline, 114.1 MW (153,000 hp) of greenfield compression and 55.9 MW (75,000 hp) of brownfield compression. Project costs were revised upwards to US$3.6 billion reflecting the impact of delays of various regulatory approvals from the FERC and other agencies, increased contractor construction costs due to unusually high demand for construction resources in the region, unusually high instances of inclement weather throughout construction, and modifications to contractor work plans to mitigate construction delays associated with these impacts.
Columbia Gas Section 4 Rate Case	
2020	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, subject to refund upon completion of the rate proceeding.
2021	In July 2021, Columbia Gas notified FERC that it reached a settlement-in-principle with its customers addressing all remaining issues in the case, including but not limited to the resolution of rates and continuation of Columbia Gas's modernization program. In October 2021, Columbia Gas filed its settlement with FERC, and is now awaiting approval, with 2021 revenues expected to be generally consistent with estimates recorded to date. In December 2021, the presiding Administrative Law Judge recommended the settlement for approval and certified it as uncontested to FERC for its review and approval. While there is no timeframe in which FERC must act on the settlement, in line with other recent rate case settlement approval timelines, we expect to receive approval of the settlement in early 2022.
Columbia Gas - VR Project	
2021	In July 2021, we approved the VR Project, a delivery market project on Columbia Gas that will replace and upgrade certain facilities while reducing emissions along portions of the Columbia Gas pipeline system in principal delivery markets. The enhanced facilities are expected to improve reliability of the system and allow for additional transportation services to address growing demand under long-term contracts while reducing direct carbon dioxide (CO_2e) emissions. The estimated US$0.7 billion project is targeted to be placed in service during the second half of 2025. The VR Project is subject to customary conditions precedent and normal-course regulatory approvals.
Columbia Gas - Modernization II	
2018 - 2020	Columbia Gas and its customers entered into a settlement arrangement, approved by the FERC, which provides recovery and return on investment to modernize its system, improve system integrity, and enhance service reliability and flexibility. The Modernization II program includes, among other things, replacement of aging pipeline and compressor facilities, enhancements to system inspection capabilities, and improvements in control systems. The Modernization II program was approved for up to US$1.1 billion of work starting in 2018 and to be completed through 2020. As per the terms of the arrangement, facilities in service by October 31 of each year collect revenues effective February 1 of the following year until the arrangement is terminated upon new rates becoming effective once Columbia Gas files a Section 4 rate case under the Natural Gas Act. Capital spend on the Modernization II program was completed in fourth quarter 2020.
Columbia Gas - Modernization III	
2021	Subject to FERC approval as part of the Columbia Gas uncontested rate settlement, Columbia Gas and its customers entered into a settlement arrangement (Modernization III) which provides recovery and return on investment to modernize its system, 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 to be completed through 2024. As per the terms of the arrangement, facilities in service by November 30 of each year collect revenues effective April 1 of the following year until the arrangement is terminated. New rates will become effective once Columbia Gas files a subsequent Section 4 rate case under the Natural Gas Act.

Date	Description of development
Columbia Gulf - Rate Settlement	
2019	In December 2019, FERC approved the uncontested Columbia Gulf rate settlement which set new recourse rates for Columbia Gulf effective August 1, 2020 and instituted a rate moratorium through August 1, 2022.
Columbia Gulf - Gulf XPress	
2019	The US$0.6 billion project was phased into service over first quarter 2019. The project is associated with the Mountaineer XPress expansion to move Appalachian supply to the Gulf Coast by the addition of seven greenfield mid-point compressor stations along the Columbia Gulf route.
Columbia Gulf - Louisiana XPress	
2019	The Louisiana XPress project will connect supply directly to U.S. Gulf Coast LNG export markets with the addition of three greenfield mid-point compressor stations along Columbia Gulf. The FERC certificate for the Louisiana XPress project was filed in July 2019. Interim service for Louisiana XPress shippers commenced in November 2019. The estimated US$0.4 billion project is expected to be placed in service in 2022.
OTHER U.S. NATURAL GAS PIPELINES	
ANR Pipeline Company (ANR Pipeline) - Grand Chenier XPress	
2019	In July 2019, we approved the Grand Chenier XPress project which will connect 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 the ANR Pipeline. The FERC certificate for the project was filed in October 2019.
2021	Phase I of Grand Chenier XPress, an expansion project on ANR connecting supply directly to U.S. Gulf Coast LNG export facilities, went into service in April 2021. Phase II was placed in service in January 2022.
ANR Pipeline - Alberta XPress	
2020	In February 2020, we approved the Alberta XPress project, an expansion project on ANR that 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. The anticipated in-service date is in the second half of 2022 with an estimated project cost of US$0.2 billion.
ANR Pipeline - Elwood Power Project/ANR Horsepower Replacement	
2020	In July 2020, we approved the Elwood Power Project/ANR Horsepower Replacement that will replace, upgrade and modernize certain facilities while reducing emissions along a highly utilized section of the ANR pipeline system. The enhanced facilities are expected to improve reliability of the ANR pipeline system and also allow for additional contracted transportation services of approximately 132 TJ/d (123 MMcf/d) to be provided to an existing power plant near Joliet, Illinois. The anticipated in-service date of the combined project is the second half of 2022 with an estimated cost of US$0.4 billion.
ANR Pipeline - Wisconsin Access	
2020	In October 2020, we approved the Wisconsin Access project that will replace, upgrade and modernize certain facilities while reducing emissions along portions of the ANR pipeline system. The enhanced facilities are expected to improve reliability of the ANR pipeline system and also allow for additional contracted transportation services of approximately 77 TJ/d (72 MMcf/d) to be provided to utilities serving the midwestern U.S. under long-term contracts. The anticipated in-service date of the combined project is the second half of 2022 with an estimated cost of US$0.2 billion.
ANR Pipeline - WR Project	
2021	In November 2021, we approved the WR Project, a delivery market project on ANR that will replace and upgrade certain facilities while reducing emissions along portions of the ANR pipeline system in principal delivery markets. The enhanced facilities are expected to improve reliability of the system and allow for additional transportation services to address growing demand in the midwestern U.S. under long-term contracts while also reducing CO_2e emissions. The estimated US$0.8 billion project is expected to be placed in service in fourth quarter 2025.
ANR Section 4 Rate Case	
2022	ANR filed a Section 4 rate case with FERC in January 2022 requesting an increase to ANR's maximum transportation rates effective August 1, 2022, subject to refund upon completion of rate proceedings. As the rate case process progresses, we expect to engage in a collaborative process to achieve settlement with our customers, FERC and other stakeholders.

Date	Description of development
Gas Transmission Northwest LLC (GTN) - GTN XPress	
2019	In October 2019, TC Pipelines, LP (TCLP) approved the GTN XPress project which is an integrated reliability and expansion project on the GTN System that will provide for the transport of additional volumes enabled by the NGTL System's West Path Delivery Program, estimated at US$0.3 billion (see the *Developments in the Canadian Natural Gas Pipelines Segment – Canadian Regulated Pipelines – NGTL System/Foothills West Path Delivery Program* section above).
2021	The GTN XPress expansion project filed its FERC certificate application in fourth quarter 2021 and is expected to be placed in service in the second half of 2023.
GTN Rate Case Settlement	
2021	In September 2021, GTN filed an uncontested rate settlement which would set new recourse rates for GTN effective January 1, 2022 and institute a rate moratorium through December 31, 2023. The uncontested rate settlement was approved by FERC in November 2021. The revised rates are not expected to have a significant impact on our U.S. Natural Gas Pipelines segment comparable earnings. In addition, GTN must file for new rates no later than April 1, 2024.
TC PipeLines, LP	
2021	In March 2021, we completed the acquisition of all of the outstanding common units of TCLP not beneficially owned by TC Energy, resulting in TCLP becoming an indirect, wholly-owned subsidiary of TC Energy. Upon close of the transaction and in accordance with the acquisition terms, TCLP common unitholders received 0.70 common shares of TC Energy for each issued and outstanding publicly-held TCLP common unit resulting in the issuance of 38 million TC Energy common shares valued at approximately $2.1 billion, net of transaction costs.

Developments in the Mexico Natural Gas Pipelines Segment

Date	Description of development
MEXICO NATURAL GAS PIPELINES	
Tula	
2019	The CFE initiated arbitration in June 2019, disputing fixed capacity payments due to force majeure events. Arbitration proceedings are suspended while management holds settlement discussions with the CFE. The east section of the Tula pipeline was fully commissioned and available for interruptible transportation services. We received capacity payments under force majeure provisions up to June 2019 but have not commenced recording revenue for accounting purposes.
2021	We are working to procure necessary land access on the west section of the Tula pipeline to finalize its construction. The central segment construction has been delayed due to pending Indigenous consultation processes under the responsibility of the Secretary of Energy. In 2021, we advanced the resolution of disputed contract terms with the signing of a Memorandum of Understanding (MOU) in July 2021 outlining main settlement principles. Feasibility assessments commenced with the CFE under the MOU to jointly evaluate potential alternatives to complete the Tula pipeline.
Villa de Reyes	
2019	The CFE initiated arbitration in June 2019, disputing fixed capacity payments due to force majeure events. Arbitration proceedings are suspended while management holds settlement discussions with the CFE. We received capacity payments under force majeure provisions up to May 2019. Payments received prior to in-service are not recognized as revenue for accounting purposes.
2021	In 2021, we advanced the resolution of disputed contract terms with the signing of an MOU in July 2021 outlining main settlement principles. Villa de Reyes construction is ongoing but completion has been delayed due to COVID-19 contingency measures and challenges gaining access to land in certain local communities. Management is working closely with state and local governments to complete negotiations and achieve access to land so that construction can be completed. We expect to complete the construction of Villa de Reyes in phases during 2022, subject to timely receipt of pending authorizations and land access to critical pipeline sections.
Sur de Texas	
2019	The Sur de Texas pipeline began commercial operation in September 2019 following execution of the amending agreement with the CFE. The original Sur de Texas agreement had a fluctuating toll profile over a 25-year contract term. As a result of the amendment, the contract has been extended 10 years and the CFE will receive transportation services for 35 years under a levelized toll structure based on actual construction costs with an initial fixed toll applicable for the first 25 years of the contract term and a higher fixed toll over the last 10 years of the contract. All other terms and conditions of the contract remain substantially unchanged. Monthly revenues for this pipeline will be recognized at a levelized average rate over the 35-year contract term.
2020	In March 2020, we recorded US$55 million of revenue related to fees associated with the successful completion of the Sur de Texas pipeline.

Further information about developments in the Natural Gas Pipelines business, including changes that we expect will occur in 2022, can be found in the MD&A in the *Natural Gas Pipelines Business* section; *Canadian Natural Gas Pipelines – Understanding our Canadian Natural Gas Pipelines Segment*, *Significant events*, *Financial results* and *Outlook* sections; *U.S. Natural Gas Pipelines – Understanding our U.S. Natural Gas Pipelines Segment*, *Significant events*, *Financial results* and *Outlook* sections; and *Mexico Natural Gas Pipelines – Understanding our Mexico Natural Gas Pipelines Segment*, *Significant events*, *Financial results* and *Outlook* sections, which sections of the MD&A are incorporated by reference herein.

LIQUIDS PIPELINES

Developments in the Liquids Pipelines Segment

Date	Description of development
Keystone Pipeline System	
2019	In early February 2019, the Keystone pipeline was temporarily shut down after a leak was detected near St. Charles, Missouri. The pipeline was restarted the same day while the segment between Steele City, Nebraska and Patoka, Illinois was restarted in mid-February 2019. In October 2019, the Keystone pipeline was temporarily shut down after a leak was detected near Edinburg, North Dakota. The pipeline was restarted in November 2019 following the approval of the repair and restart plan by PHMSA.
Keystone XL	
2019	In March 2019, the U.S. President issued a new U.S. Presidential Permit (2019 Presidential Permit) for the Keystone XL pipeline which superseded a Presidential Permit that was issued in 2017 (2017 Presidential Permit). This resulted in the dismissal of certain legal claims related to the 2017 Presidential Permit and an injunction barring certain pre-construction activities and construction of the project. The lawsuits were expanded to include challenges to the 2019 Presidential Permit, and proceeded in federal district court in Montana. In August 2019, the Nebraska Supreme Court affirmed the November 2017 decision by the Nebraska Public Service Commission approving the Keystone XL pipeline route through the state. The DOS issued a final supplemental environmental impact statement (SEIS) for the project in December 2019. The final SEIS supplements the 2014 Keystone XL SEIS and underpins the U.S. Bureau of Land Management (BLM) and U.S. Army Corps of Engineers (USACE) permits.
2020	In February 2020, we received approval from the BLM allowing for the construction of the Keystone XL pipeline across federally managed lands in Montana and land managed by the USACE at the Missouri River. In March 2020, we announced that we would proceed with construction of the Keystone XL pipeline which commenced in April 2020. We advanced construction of 180 km (112 miles) of pipeline and five pump stations in Canada, 12 pump stations in the United States, and completed the U.S./Canada border crossing in June 2020. As part of the Keystone XL pipeline funding plan, the Government of Alberta invested approximately US$0.8 billion in equity as of December 31, 2020 which substantially funded construction costs through the end of 2020. In August 2020, we announced that the Keystone XL pipeline had committed to construct the project using all union labour in the U.S. along with committing in excess of $10 million to create a Green Jobs Training Fund to help train union workers on renewable energy projects. In November 2020, we signed an agreement with Natural Law Energy, which included a potential investment by five First Nations in Alberta and Saskatchewan, of up to $1.0 billion in Keystone XL and future liquids projects.
2021	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. The Keystone XL investment was evaluated for impairment in 2021 along with our investments in related capital projects including Heartland Pipeline, TC Terminals and Keystone Hardisty Terminal. We determined that the carrying amount of these assets was no longer fully recoverable. As a result, we 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 ended December 31, 2021 which was excluded from comparable earnings. Although we recorded a $2.1 billion after-tax asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations related to the Keystone XL pipeline project termination activities, a significant portion of this amount 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 to 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 2022. We will coordinate with regulators, stakeholders and Indigenous groups to meet our environmental and regulatory commitments and ensure a safe exit from the Keystone XL pipeline project. The majority of these associated costs were funded through a final drawdown on the project-level credit facility which occurred in June 2021, subsequent to which the project-level credit facility was fully repaid by the Government of Alberta and terminated. We continue to manage legacy challenges to the 2019 Presidential Permit and the BLM Grant of Right-of-Way, which remain pending before the federal district court in Montana in a manner consistent with the termination of the project. In November 2021, we filed a Request for Arbitration to formally initiate a legacy NAFTA claim to recover economic damages resulting from the revocation of the 2019 Presidential Permit for the Keystone XL pipeline project. We will be seeking to recover more than US$15 billion in damages as a result of the U.S. Government's breach of its NAFTA obligations. This claim is in a preliminary stage with the timing and ultimate outcome unknown at present.

Date	Description of development
Northern Courier	
2019	In July 2019, we completed the sale of an 85 per cent equity interest in Northern Courier to AIMCo for gross proceeds of $144 million, before post-closing adjustments, resulting in a pre-tax gain of $69 million after recording our remaining 15 per cent interest at fair value. The after-tax gain of $115 million reflects the utilization of prior years' previously unrecognized tax loss benefits. Preceding the equity sale, Northern Courier issued $1.0 billion of long-term, non-recourse debt, the proceeds from which were paid to TC Energy resulting in aggregate gross proceeds to TC Energy of $1.15 billion from this asset monetization. We remain the operator of the Northern Courier pipeline and are using the equity method to account for our remaining 15 per cent interest in our Consolidated financial statements.
2021	In November 2021, we received $35 million in proceeds from the monetization of our remaining 15 per cent equity interest in Northern Courier to Astisiy Limited Partnership, a partnership comprised of Suncor Energy Inc. and eight Indigenous communities in the Regional Municipality of Wood Buffalo.
Port Neches	
2021	In March 2021, we entered a joint venture with Motiva Enterprises (Motiva) to construct the US$152 million Port Neches Link pipeline system which will 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 will also include facilities to tie in additional liquids terminals to the Keystone Pipeline System with other downstream infrastructure and is expected to be in service in the second half of 2022.

Further information about developments in the Liquids Pipelines business, including changes that we expect will occur in 2022, can be found in the MD&A in the *Liquids Pipelines – Understanding our Liquids Pipelines business*, *Significant events*, *Financial results* and *Outlook* sections, which sections of the MD&A are incorporated by reference herein.

POWER AND STORAGE

Developments in the Power and Storage Segment

Date	Description of development
CANADIAN POWER	
Ontario Natural Gas-Fired Power Plants	
2019	In March 2019, Napanee experienced an equipment failure while progressing commissioning activities which delayed the initial startup. In July 2019, we entered into an agreement to sell our Halton Hills and Napanee power plants as well as our 50 per cent interest in Portlands Energy Centre (PCE) to a subsidiary of Ontario Power Generation Inc. (OPG).
2020 - 2021	In March 2020, we placed the Napanee power plant into service. In April 2020, we completed the sale of our Halton Hills and Napanee power plants as well as our 50 per cent interest in PCE to a subsidiary of OPG for net proceeds of approximately $2.8 billion before post-closing adjustments. The total pre-tax loss of $676 million ($470 million after tax) on this transaction includes losses accrued during 2019 while classified as an asset held for sale and a 2021 post-close adjustment as well as utilization of previously unrecognized tax loss benefits. This loss may be amended in the future upon the settlement of existing insurance claims.
Sharp Hills Wind Power Purchase Agreement (PPA)	
2021	In September 2021, we executed a 15-year PPA for 100 per cent of the power produced and the rights to all environmental attributes from the 297 MW Sharp Hills Wind Farm located in eastern Alberta. The Sharp Hills Wind Farm is anticipated to be operational in 2023, subject to customary regulatory approvals and conditions.
Bruce Power	
2019	In April 2019, Bruce Power's contract price increased from approximately $68 per MWh to a final adjusted contract price of approximately $78 per MWh including flow-through items, reflecting capital to be invested under the Unit 6 MCR program and the Asset Management program as well as annual inflation adjustments.
2020	Bruce Power's Unit 6 MCR outage commenced in January 2020 and is expected to be completed in 2023. In late March 2020, as a result of COVID-19 impacts, Bruce Power declared force majeure under its contract with the IESO. This force majeure notice covered the Unit 6 MCR and certain Asset Management work. In May 2020, work on the Unit 6 MCR and Asset Management programs were restarted with additional prevention measures in place for worker safety related to COVID-19. The impact of the force majeure will ultimately depend on the recovery of any impacts in accordance with the force majeure provisions of the IESO contract. In October 2020, the Unit 6 MCR project achieved a major milestone with the completion of the preparation phase and commencement of the Fuel Channel and Feeder Replacement Program. Operations on the remaining units continue as normal with the scheduled outages successfully completed on Unit 3, 4 and 5 in second quarter of 2020 and on Unit 8 in fourth quarter 2020. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available for Bruce Power and the IESO.
2021	In mid-2021, as part of the planned inspections, testing, analysis and maintenance activities at Bruce Power during the current 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. Bruce Power will be incorporating additional inspections as part of their normal surveillance programs to address the new 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 program continues on schedule and on budget; however, COVID-19 may have an impact on cost and schedule contingency. As applicable, Bruce Power will seek recovery of any impacts in accordance with the force majeure provisions of the IESO contract. The program is nearing the end of the Inspection Phase and has entered the Installation Phase. Preparation of the Unit 3 MCR program, which is the next scheduled MCR outage, continues and Bruce Power submitted its final cost and schedule duration estimate to the IESO in December 2021. As well, Bruce Power submitted its initial preliminary cost and schedule duration estimate for the Unit 4 MCR program, which is the next unit scheduled after Unit 3. 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.

Date	Description of development
Ontario Pumped Storage Project	
2021	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 Ontario Pumped Storage project, an energy storage facility located near Meaford, Ontario that would provide 1,000 MW of flexible, clean energy to Ontario's electricity system using a process known as pumped hydro storage. Two key milestones on the Ontario Pumped Storage project were reached in 2021. 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 will store emission-free energy when available and provide it 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.
Coolidge Generating Station	
2019	In May 2019, we completed the sale of the Coolidge generating station to Salt River Agriculture Improvement and Power District as per the terms of their right of first refusal, for proceeds of US$448 million, before post-closing adjustments, resulting in a pre-tax gain of $68 million ($54 million after tax).
TransCanada Turbines Ltd.	
2020	In November 2020, we acquired the remaining 50 per cent ownership interest in TransCanada Turbines Ltd. for cash consideration of US$67 million.
U.S. POWER	
2021	Through a request for information (RFI) process 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 to meet the electricity needs of the U.S. portion of the Keystone Pipeline System assets. 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. We received a significant number of responses to our RFI and are currently evaluating proposals and expect to finalize contracts during the first half of 2022.
Monetization of U.S. Northeast Power Business	
2019	In May 2019, we sold our remaining U.S. Northeast power marketing contracts. This transaction concludes the wind-down of our U.S. Northeast power marketing business, following the sale of our U.S. power retail contracts in 2018.

Further information about developments in the Power and Storage business, including changes that we expect will occur in 2022, can be found in the MD&A in the *Power and Storage – Understanding our Power and Storage Business*, *Significant events*, *Financial results* and *Outlook* sections, which sections of the MD&A are incorporated by reference herein.

OTHER ENERGY TRANSITION DEVELOPMENTS

Our vision is to be the premier energy infrastructure company in North America today and in the future. That future includes embracing the energy transition that is underway and contributing to a lower-carbon energy world. As energy transition continues to evolve, we recognize a significant opportunity to reduce our emissions footprint, in addition to being a partner to our customers and other industries which are also looking for low-carbon solutions. Currently, it is uncertain how the energy mix will evolve and at what pace. We continue to observe a reliance on the existing sources of natural gas, crude oil and electricity, for which we currently provide services to our customers.

We are targeting five focus areas to reduce the emissions intensity of our operations, while also capturing growth opportunities that meet the energy needs of the future:

- modernize our existing system and assets
- decarbonize our energy consumption
- drive digital solutions and technologies
- leverage carbon credits and offsets
- invest in low-carbon energy and infrastructure, such as renewables along with emerging fuels and technology.

Further information about developments in our business, including changes that we expect will occur in 2022 around these developments, can be found in the *About our business - Capital Program - Other Energy Transition Developments* section of the MD&A, which section of the MD&A is incorporated by reference herein.

Business of TC Energy

Our business is made up of pipeline and storage assets that transport, store or deliver natural gas and crude oil as well as power generation assets that produce electricity to support businesses and communities across the continent.

Our vision is to be the premier energy infrastructure company in North America today and in the future, focused on transporting and delivering the energy people need every day. Our goal is to develop and build a portfolio of infrastructure assets that will enable us to prosper irrespective of the pace and direction of energy transition. Refer to the *About our business – 2021 Financial highlights - Consolidated results* section of the MD&A for our revenues from operations by segment, for the years ended December 31, 2021 and 2020, which section of the MD&A is incorporated by reference herein.

The following is a description of each of TC Energy's three core businesses.

NATURAL GAS PIPELINES

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.

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 535 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.

A description of the natural gas pipelines and regulated natural gas storage assets we operate in addition to further information about our pipeline holdings, developments and opportunities, significant regulatory developments and competitive position which relate to our Natural Gas Pipelines business can be found in 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 of the MD&A are incorporated by reference herein.

LIQUIDS PIPELINES

Our existing liquids pipelines infrastructure connects Alberta crude oil supplies to U.S. refining markets in Illinois, Oklahoma and the U.S. Gulf Coast as well as U.S. crude oil supplies from the key market hub at Cushing, Oklahoma to the U.S. Gulf Coast. We also provide intra-Alberta liquids transportation.

A description of pipelines and properties we operate, in addition to further information about our pipeline holdings, developments and opportunities, significant regulatory developments and competitive position which relate to our Liquids Pipelines business can be found in the MD&A in the *Liquids Pipelines* section, which section of the MD&A is incorporated by reference herein.

REGULATION OF NATURAL GAS PIPELINES AND LIQUIDS PIPELINES

Canada

Natural Gas Pipelines

With the exception of Coastal GasLink (which is currently under construction), all of our major Canadian natural gas pipeline systems are regulated by the CER (formerly, the NEB) under the *Canadian Energy Regulator Act*.

The CER regulates the construction and operation of facilities for these systems. TC Energy project applications are assessed by the CER, and depending on the project scope, may also require approval of the federal government. Should TC Energy propose a major project that is designated under the *Impact Assessment Act*, it would require assessment by an integrated review panel of the Impact Assessment Agency of Canada and the CER, as well as federal government approval.

The CER also regulates the terms and conditions of services, including rates, for these systems. The CER approves tolls and services that provide TC Energy the opportunity to recover costs of transporting natural gas, including the return of capital (depreciation) and return on the average investment base for our Canadian natural gas pipeline systems. Generally, Canadian natural gas pipelines request the CER to approve the pipeline's cost of service and tolls once a year, and recover or refund the variance between actual and expected revenues and costs in future years. Net earnings may be affected by changes in investment base, ROE and regulated capital structure as well as by the terms of toll settlements approved by the CER.

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. Further information relating to the 2020-2024 Settlement can be found in the *General development of the business - Natural Gas Pipelines – Developments in the Canadian Natural Gas Pipelines Segmen*t - *Canadian Regulated Pipelines - NGTL System - Revenue Requirement Settlements* section above and in the *Canadian Natural Gas Pipelines - Financial Results* and *Other information - Quarterly Results - Highlights by business segment* sections of the MD&A, which section of the MD&A is incorporated by reference herein.

The Canadian Mainline is operating under a six-year toll settlement for 2021-2026 which includes an incentive to decrease costs and increase revenues. Further information relating to the Canadian Mainline Settlement can be found in the *General development of the business - Natural Gas Pipelines – Developments in the Canadian Natural Gas Pipelines Segment - Canadian Regulated Pipelines - Canadian Mainline Settlement* section above and in the *Canadian Natural Gas Pipelines – Financial Results* section of the MD&A, which section of the MD&A is incorporated by reference herein.

Coastal GasLink Pipeline Project

The Coastal GasLink natural gas pipeline project is being developed primarily under the regulatory regime administered by the OGC and the BCEAO. The OGC is responsible for overseeing oil and gas operations in B.C., including exploration, development, pipeline transportation and reclamation. The BCEAO is an agency that manages the review of proposed major projects in B.C., as required by the B.C. *Environmental Assessment Act*.

Liquids Pipelines

The CER regulates the terms and conditions of service, including rates, construction and operation of the Canadian portion of the Keystone Pipeline System. The rates for transportation service on the Keystone Pipeline System are calculated in accordance with a methodology agreed to in transportation service agreements between Keystone pipeline and its shippers, and approved by the CER. The White Spruce and Grand Rapids pipelines are regulated by the AER. The AER regulates the construction and operation of pipelines and associated facilities in Alberta.

United States

Natural Gas Pipelines

TC Energy is subject to regulation by various federal, state and local governmental agencies, including those specifically described below.

The Company's wholly-owned and partially-owned U.S. pipelines and natural gas storage facilities are considered *natural gas companies* subject to the jurisdiction of the FERC. The *Natural Gas Act of 1938* grants the FERC authority over the construction, acquisition and operation of pipelines and related facilities utilized in the transportation and sale of natural gas in interstate commerce, including the extension, enlargement or abandonment of service using such facilities. The FERC also has authority to regulate rates and charges for transportation and storage of natural gas in interstate commerce. Pipeline safety is regulated by PHMSA. Natural gas pipelines that cross the international border between Canada and the U.S., such as the Great Lakes Gas Transmission Limited Partnership (Great Lakes), GTN System and Portland Natural Gas Transmission System pipelines, require a Presidential Permit from the DOS.

Liquids Pipelines

The FERC regulates the terms and conditions of service, including transportation rates, of interstate liquids pipelines, including the U.S. portion of the Keystone Pipeline System and Marketlink. The siting and construction of pipeline facilities are regulated by the specific state regulator in which the pipeline facilities are located. Pipeline safety is regulated by PHMSA. Liquids pipelines that cross the international border between Canada and the U.S., such as the Keystone pipeline, require a Presidential Permit. Liquids pipeline projects that cross federal lands or waters of the U.S. require additional federal permits.

Mexico

Natural Gas Pipelines

TC Energy's pipelines in Mexico are regulated by the Comisión Reguladora de Energía (CRE) who authorizes the transmission services of all gas pipeline infrastructure. Accordingly, our Mexican pipelines have CRE-approved tariffs, services and related rates; however, the contracts underpinning the construction and operation of these facilities are long-term negotiated fixed-rate contracts. Our contractual rates are only subject to change under specific circumstances such as changes in law.

POWER AND STORAGE

Our power business includes approximately 4,300 MW of generation capacity located in Alberta, Ontario, Québec and New Brunswick, using natural gas and nuclear fuel sources and is generally supported by long-term contracts. Additionally, we are pursuing generation assets and PPA opportunities in Canada and the United States.

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

Further information about Power and Storage assets we operate and those currently under construction, along with our Power and Storage holdings, significant developments, and opportunities in relation to our Power and Storage business, can be found in the MD&A in the *Power and Storage* section, which section of the MD&A is incorporated by reference herein.

General

EMPLOYEES

At Year End, TC Energy's principal operating subsidiary, TCPL, had 7,017 employees, substantially all of whom were employed in Canada and the U.S., as set forth in the following table.

Calgary	2,653
Western Canada (excluding Calgary)	634
Eastern Canada	232
Houston	807
U.S. Midwest	766
U.S. Northeast	201
U.S. Southeast/ Gulf Coast (excluding Houston)	1,136
U.S. West Coast	80
Mexico	508
Total	**7,017**

HEALTH, SAFETY, SUSTAINABILITY AND ENVIRONMENTAL PROTECTION AND SOCIAL POLICIES

The Board of Directors' (the Board) Health, Safety, Sustainability and Environment (HSSE) Committee oversees operational risk, occupational and process safety, sustainability, security of personnel, environmental and climate change related risks and monitors development and the 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, programs and procedures.

Our management system, TOMS, is modeled after international standards, including the International Organization for Standardization (ISO) standard for environmental management systems, ISO 14001, and the Occupational Health and Safety Assessment Series for occupational health and safety. TOMS also conforms to applicable industry standards and complies with applicable regulatory requirements. It covers the lifecycle of our assets and follows a continuous improvement cycle organized into four key areas:

- Plan – risk and regulatory assessment as well as objective and target setting, which includes establishing total recordable case rate targets while striving for zero incidents plus defining roles and responsibilities
- Do – development and implementation of programs, procedures and standards to manage operational risk
- Check – incident reporting, investigation, assurance activities, including internal and external audits and performance monitoring
- Act – non-conformance, non-compliance and opportunities for improvement are managed and assessed by management.

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

- overall HSSE corporate governance
- operational performance and preventative maintenance metrics
- asset integrity programs
- environment programs
- significant occupational safety, process safety and asset integrity incidents
- emergency preparedness, incident response and evaluation
- occupational and process safety performance metrics
- 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, that 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, Reconciliation Action Plan, ESG Data Sheet and GHG Emissions Reduction Plan
- our Occupational Health and Hygiene Program, which includes physical and mental health and psychological safety.

The HSSE Committee also receives updates on any specific areas of operational and construction risk management review being conducted by management and the results and corrective action plans flowing from internal and third party audits. Information about the financial and operational effects of environmental protection requirements on the capital expenditures, profit or loss and competitive position of TC Energy can be found in the MD&A in the *Other information – Enterprise risk management – Health, safety, sustainability and environment* section, which section of the MD&A is incorporated by reference herein. Generally, each year the HSSE Committee or the HSSE Committee Chair tours one of our existing assets or projects under development as part of its responsibility to monitor and review our health, safety, sustainability and environmental practices. Additionally, the Board and the HSSE Committee typically have an opportunity to have a joint site visit annually.

Health and Safety

As one of our corporate values, safety is an integral part of the way our employees work. Each year we develop goals predicated on achieving year over year sustainable improvement in our safety performance, and meeting or exceeding industry benchmarks.

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

We annually conduct emergency response exercises to practice effective coordination between the Company, local emergency responders, regulatory agencies and government officials in the event of an emergency. TC Energy uses the Incident Command System (ICS), a standardized approach to command, control and coordinate emergency responses. The ICS model supports a unified approach to emergency response with these community members. We also provide annual training to all field staff in the form of table top exercises, online and vendor lead training.

Environmental risk, compliance and liabilities

TOMS provides requirements for our day-to-day work to protect employees, contractors, our workplace and assets, the communities in which we work and the environment. It conforms to external industry consensus standards and voluntary programs plus complies with applicable legislative requirements. Under TOMS, mandated programs set requirements to manage specific risk areas for TC Energy, including the Environment Program, which is a documented set of processes and procedures that identifies our requirements to proactively and systematically manage environmental hazards and risks throughout the lifecycle of our assets. As part of our Environment Program, 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. To conserve and protect the environment during construction, information gathered for an environmental impact assessment is used to develop project-specific environmental protection plans. Additionally, the Environment Program, which applies to all of our operations, includes practices and procedures to manage potential adverse environmental effects to these resources during the full lifecycle of our facilities.

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, that 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, that 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.

Through the implementation of our Environment Program, we 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.

Social Policies

We have a number of corporate governance documents including commitment statements, policies and standards to help manage Indigenous and stakeholder relations. 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. All employees (including executive officers) and directors must certify their compliance with COBE.

Our approach to Indigenous and stakeholder engagement is based on building relationships, mutual respect and trust while recognizing the unique values, needs and interests of each community. Our Indigenous Relations and Stakeholder Engagement Commitment Statements provide the structure to 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.

Our Indigenous Relations Policy is informed by our guiding principles and corporate values to ensure meaningful and respectful engagement and dialogue based on a principled and transparent approach. We work together with Indigenous groups to find mutually acceptable solutions to address concerns and identify opportunities to foster long-term relationships in support of TC Energy's business and sustainability objectives. This policy recognizes the diversity of Indigenous groups, their unique connection to land, and the imperative of building relationships based on mutual respect and trust. We strive to be considered as a partner of choice for Indigenous groups. We seek to play a meaningful role in reconciliation with Indigenous Peoples and groups through our efforts.

We also have an Avoiding Bribery and Corruption Program which includes an Avoiding Bribery and Corruption Policy, annual online training provided to all personnel, face to face 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.

We work to understand and mitigate the complexity of ESG issues, and the interconnectivity of these issues as they relate to our business. These issues 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 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 United States and Mexico, we support access to basic human rights such as 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 Storage – Business risks* and *Other information – Enterprise risk management* sections, which sections of the MD&A 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, 2022, are set out in the MD&A under the heading *About our business – 2021 Financial highlights – Dividends* section, which section of the MD&A 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 of the MD&A 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 ensure, to the extent possible, that all shareholders of TC Energy are treated fairly in connection with any take-over bid for the Company. 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 2019 annual and special 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 2022 annual meeting of TC Energy shareholders.

Under TC Energy's 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 acquired on the open market at 100 per cent of the weighted average purchase price. Refer to the *About our business - 2021 Financial highlights – Dividends - Dividend Reinvestment Plan* section of the MD&A, which section of the MD&A is incorporated by reference herein.

TC Energy also has a stock based compensation plan that allows some employees to acquire common shares of TC Energy upon exercise of options granted thereunder. Option exercise prices are equal to the closing price on the TSX on the last trading day immediately preceding the grant date. Options granted under the plan are generally fully exercisable after three years and expire seven years after the date of grant.

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 directors if TC Energy fails to pay dividends on that series of preferred shares for any period as may be so determined by the directors. 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, 11 and 15 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 (subject, in the case of the Series 15 preferred shares, to a fixed minimum reset rate of 4.90 per cent) and have the right to convert their shares into cumulative redeemable Series 2, 4, 6, 8, 10, 12 and 16 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, 11 and 15 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, 12 and 16 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, 11 and 15 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, 12 and 16 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, 12, 15 and 16 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 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
Series 13 preferred shares[2]	May 31, 2021	May 31, 2021	—
Series 14 preferred shares[3]	—	—	—
Series 15 preferred shares	May 31, 2022	May 31, 2022 and every fifth year thereafter	3.85
Series 16 Preferred shares	—	May 31, 2027 and every fifth year thereafter	3.85

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.

[2] On May 31, 2021, TC Energy redeemed all of its issued and outstanding Series 13 preferred shares. Subsequent to the redemption, the Series 13 preferred shares ceased to be listed on the TSX and were canceled.

[3] Prior to the redemption of the Series 13 preferred shares, Series 14 preferred shares were issuable upon conversion of the Series 13 preferred shares, subject to certain conditions, on previously set conversion dates. At the time of the redemption and cancellation of the Series 13 preferred shares, there were no Series 14 preferred shares outstanding.

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 Baa2 with a stable outlook, S&P has assigned an issuer credit rating of BBB+ with a stable outlook, and Fitch has assigned a long-term issuer default rating of A- 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	Baa1	BBB+	A-	A (low)
TCPL - Junior subordinated notes	Baa2	BBB-	Not rated	BBB
TransCanada Trust - Subordinated trust notes	Baa3	BBB-	BBB	Not rated
TC Energy Corporation - Preferred shares	Not rated	P-2 (Low)	BBB	Pfd-2 (low)
Commercial paper (TCPL and TCPL guaranteed)	P-2	A-2	F2	R-1 (low)
Trend/ rating outlook	Stable	Stable	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 Baa1 rating assigned to TCPL's senior unsecured debt is 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 Baa2 rating assigned to TCPL's junior subordinated notes and the Baa3 rating assigned to the TransCanada Trust subordinated trust notes, are in the fourth highest of nine rating categories for long-term obligations, with the junior subordinated notes ranking higher within the Baa rating category with a modifier of 2 as opposed to the modifier of 3 on the subordinated trust notes. 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.

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.

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 A- rating assigned to TCPL's senior unsecured debt is in the third highest of 11 rating categories for long-term obligations. An A rating indicates that expectations of default risk are low and that the obligor's capacity to meet its financial commitment is strong; however, the obligation is somewhat more vulnerable to the adverse effects of changes in circumstances and economic conditions than obligations in higher rated categories. The BBB rating assigned to the TransCanada Trust subordinated trust notes and TC Energy's preferred shares is in the fourth highest of 11 rating categories for long-term obligations. A BBB rating indicates that expectations of default risk are low and that the capacity for payment of financial commitments is considered adequate, however, adverse economic conditions or adverse business conditions are more likely to impair the capacity of the obligor to meet its financial commitment on the obligation. 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 payments of short-term debt obligations.

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 A (low) rating assigned to TCPL's senior unsecured debt is in the third highest of 10 categories for long-term debt and indicates good credit quality. The capacity for the payment of financial obligations is substantial, but of lesser credit quality than that of higher rating categories. Long-term debt rated A may be vulnerable to future events but qualifying negative factors are considered manageable. The BBB rating assigned to junior subordinated notes is in the fourth highest of the 10 categories for long-term debt and indicates adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, but may be vulnerable to future events. The Pfd-2 (low) rating assigned to TC Energy's preferred shares is in the second highest of six rating categories for preferred shares. Preferred shares rated Pfd-2 are generally of good credit quality. Protection of dividends and principal is still substantial; however, earnings, the balance sheet and coverage ratios are not as strong as Pfd-1 rated companies. In general, Pfd-2 ratings correspond with companies whose long-term debt is rated in the A category. The R-1 (low) rating assigned to TCPL's Canadian commercial paper program is in the third highest of 10 rating categories for short-term debt issuers and indicates good credit quality. The capacity for payment of short-term financial obligations as they fall due is substantial, although the overall strength is not as favourable as higher rating categories. Short-term debt rated R-1 (low) may be vulnerable to future events, but qualifying negative factors are considered manageable.

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
Series 15 preferred shares	November 21, 2016	TRP.PR.K

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, 11, 13 and 15 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 2021	$60.99	$57.71	$58.83	116,558,117	$47.77	$44.77	$46.54	38,930,922
November 2021	$67.68	$59.61	$59.92	63,321,436	$54.71	$46.58	$46.91	34,642,447
October 2021	$68.20	$60.26	$66.95	116,092,860	$55.34	$47.73	$54.10	28,635,375
September 2021	$64.13	$59.94	$60.96	129,420,010	$50.71	$47.47	$48.09	37,024,025
August 2021	$61.44	$57.80	$59.90	39,210,208	$49.12	$44.83	$47.48	24,519,602
July 2021	$62.78	$59.34	$60.82	72,892,076	$50.39	$46.46	$48.73	22,859,123
June 2021	$65.44	$60.93	$61.34	128,638,936	$53.65	$49.21	$49.52	41,596,853
May 2021	$62.93	$59.63	$60.92	48,852,530	$51.92	$49.28	$51.06	29,318,491
April 2021	$61.26	$57.42	$60.81	100,124,398	$49.85	$45.63	$49.47	35,979,853
March 2021	$60.48	$53.40	$57.61	169,806,343	$48.07	$42.17	$45.75	79,102,586
February 2021	$58.11	$53.20	$53.30	48,495,888	$45.69	$41.89	$41.93	43,279,456
January 2021	$57.55	$51.26	$54.81	84,712,087	$45.61	$40.17	$42.93	49,067,319

TC Energy Corporate ATM program

In December 2020, we established a new ATM program that allows us to issue common shares from treasury having an aggregate gross sales price of up to $1.0 billion, or the U.S. dollar equivalent, to the public from time to time, at our discretion, at the prevailing market price when sold through the TSX, the NYSE, or any other applicable existing trading market for TC Energy common shares in Canada or the U.S. While not a component of our base funding plan, the ATM program, which is effective for a 25-month period, provides additional financial flexibility in support of our consolidated credit metrics and capital program and may be activated if, and as, deemed appropriate. No common shares were issued under the program in 2021 or 2020. Further information about our ATM program can be found in the *Financial Condition - TC Energy Corporate ATM program* section of the MD&A, which section of the MD&A is incorporated by reference herein.

PREFERRED SHARES

Month	Series 1	Series 2	Series 3	Series 4	Series 5	Series 6	Series 7	Series 9	Series 11	Series 13[4]	Series 15
December 2021											
High	$18.83	$18.50	$14.45	$13.78	$15.99	$16.00	$21.75	$21.73	$24.24	—	$25.65
Low	$17.62	$16.30	$13.15	$12.80	$14.60	$13.67	$20.59	$20.39	$22.68	—	$25.14
Close	$18.83	$18.24	$14.45	$13.78	$15.99	$15.30	$21.60	$21.50	$24.23	—	$25.57
Volume Traded	120,365	46,846	51,770	20,219	120,682	8,292	157,797	172,266	92,435	—	228,948
November 2021											
High	$20.20	$18.87	$14.99	$15.00	$16.60	$16.50	$22.60	$22.48	$24.72	—	$25.77
Low	$18.91	$18.23	$13.96	$13.54	$15.32	$15.15	$21.30	$21.11	$23.00	—	$25.15
Close	$18.95	$18.25	$13.99	$13.55	$15.51	$15.15	$21.30	$21.11	$23.41	—	$25.15
Volume Traded	118,535	74,852	220,511	25,100	149,783	15,263	127,016	135,023	108,447	—	226,844
October 2021											
High	$20.08	$18.80	$14.81	$14.49	$16.34	$16.25	$22.55	$22.40	$24.81	—	$25.73
Low	$18.76	$17.00	$13.57	$13.16	$15.59	$14.99	$21.43	$21.10	$24.18	—	$25.56
Close	$20.08	$18.64	$14.81	$14.49	$16.34	$15.83	$22.55	$22.33	$24.73	—	$25.70
Volume Traded	134,019	32,973	171,780	18,127	309,787	6,400	305,581	154,955	93,003	—	259,325
September 2021											
High	$18.91	$17.44	$13.70	$13.50	$15.70	$14.84	$21.45	$21.27	$24.24	—	$25.71
Low	$18.11	$16.27	$12.92	$12.50	$14.44	$14.36	$20.65	$20.52	$23.45	—	$25.34
Close	$18.83	$17.22	$13.60	$13.15	$15.48	$14.82	$21.44	$21.18	$24.04	—	$25.67
Volume Traded	193,221	50,340	165,365	15,933	182,520	3,522	165,672	338,729	91,068	—	391,511
August 2021											
High	$19.99	$17.10	$13.50	$13.75	$15.29	$14.96	$21.46	$21.00	$24.08	—	$25.79
Low	$18.21	$16.40	$13.05	$12.70	$14.42	$13.95	$20.27	$20.07	$23.04	—	$25.42
Close	$18.60	$16.93	$13.26	$13.10	$14.67	$14.63	$21.13	$20.90	$23.85	—	$25.73
Volume Traded	168,613	75,100	69,320	21,620	314,121	6,446	198,315	105,124	88,296	—	384,428
July 2021											
High	$19.13	$17.90	$13.86	$13.75	$15.30	$15.20	$21.19	$21.09	$24.25	—	$25.80
Low	$18.20	$16.54	$13.10	$12.06	$14.42	$13.65	$20.40	$20.01	$23.44	—	$25.40
Close	$18.84	$17.20	$13.50	$13.01	$15.25	$14.91	$21.19	$21.09	$23.88	—	$25.75
Volume Traded	184,503	44,755	89,137	16,300	175,831	2,877	344,818	286,203	358,985	—	219,123
June 2021											
High	$19.54	$17.59	$14.41	$13.90	$15.77	$15.50	$22.18	$22.03	$24.24	—	$25.95
Low	$17.99	$16.51	$13.46	$12.80	$14.85	$14.00	$20.57	$20.53	$23.33	—	$25.41
Close	$18.79	$17.13	$13.56	$13.17	$15.08	$14.95	$20.57	$20.53	$23.70	—	$25.52
Volume Traded	624,480	38,908	64,920	16,435	275,574	15,793	228,877	161,717	280,885	—	773,498
May 2021											
High	$18.31	$17.00	$14.02	$13.90	$15.18	$14.88	$21.55	$21.45	$23.45	$25.34	$25.82
Low	$17.04	$15.45	$12.99	$12.15	$14.23	$13.40	$19.30	$19.30	$22.10	$24.98	$25.35
Close	$18.06	$16.57	$13.96	$13.20	$15.18	$14.56	$21.55	$21.45	$23.34	$24.99	$25.69
Volume Traded	210,890	38,671	99,124	25,200	206,485	2,971	498,336	347,006	282,845	880,873	938,406
April 2021											
High	$17.13	$16.14	$13.52	$12.90	$14.51	$14.25	$19.48	$19.78	$22.06	$25.32	$25.81
Low	$16.50	$15.22	$12.50	$11.62	$13.65	$12.99	$18.63	$18.48	$20.73	$25.25	$25.18
Close	$17.13	$15.55	$13.10	$12.35	$14.36	$13.61	$19.45	$19.38	$22.05	$25.32	$25.81
Volume Traded	413,994	345,460	512,184	30,499	113,486	5,136	321,806	186,429	152,441	1,046,286	552,717
March 2021											
High	$17.42	$16.74	$12.83	$13.00	$14.15	$14.06	$19.75	$19.68	$21.44	$25.48	$25.71
Low	$15.40	$14.05	$11.59	$10.73	$12.87	$12.30	$18.50	$18.09	$19.93	$25.20	$25.07
Close	$16.84	$15.42	$12.50	$11.70	$13.58	$13.25	$19.05	$19.01	$20.85	$25.29	$25.30
Volume Traded	705,745	605,625	379,257	25,603	198,072	7,550	648,154	404,070	357,973	1,568,531	459,576
February 2021											
High	$15.75	$14.47	$11.98	$11.68	$12.99	$12.55	$18.82	$18.39	$19.95	$25.50	$26.11
Low	$13.80	$12.17	$9.96	$8.92	$10.90	$10.51	$16.25	$15.92	$17.40	$25.15	$24.91
Close	$15.68	$14.15	$11.69	$10.95	$12.80	$12.26	$18.51	$18.20	$19.85	$25.25	$25.50
Volume Traded	548,196	125,963	542,852	64,489	270,794	12,404	357,991	341,923	193,909	327,955	949,173
January 2021											
High	$13.98	$12.64	$10.48	$9.79	$11.34	$10.95	$16.69	$16.34	$18.08	$25.83	$25.39
Low	$13.15	$11.36	$9.43	$8.41	$10.41	$10.27	$14.93	$14.82	$16.80	$25.25	$24.80
Close	$13.89	$12.49	$10.01	$9.47	$10.95	$10.51	$16.30	$16.02	$17.37	$25.34	$24.95
Volume Traded	403,896	44,537	307,429	34,513	171,273	22,136	309,594	208,014	84,200	124,611	536,067

[4] TC Energy's cumulative redeemable first preferred shares, Series 13, were listed on the TSX under the symbol TRP.PR.J until their redemption on May 31, 2021.

Directors and officers

As of February 14, 2022, 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 370,174 common shares, constituting 0.04 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 14, 2022, 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
Stéphan Crétier Dubai, United Arab Emirates	Chairman, President and Chief Executive Officer (CEO), GardaWorld Security Corporation (GardaWorld) (private security services) and director of a number of GardaWorld's direct and indirect subsidiaries, since 1999.	2017
Michael R. Culbert Calgary, Alberta Canada	Corporate director. Director, 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. Director and President, Pacific NorthWest LNG LP (PNW LNG LP) (liquified natural gas liquefaction and export facilities) from June 2012 to May 2017. Co-founder, Director, President and CEO, Progress Energy Ltd. (Progress Energy) (oil and gas, exploration and production) from November 2001 to November 2016.	2020
William D. Johnson Knoxville, Tennessee U.S.A.	Corporate director. President and CEO, Pacific Gas & Electric Corporation (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, ARC Resources Ltd. (ARC) (previously Seven Generations Energy Ltd.) (oil and gas, exploration and production) since May 2020. 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. Chief Legal Officer, Agrium Inc. (agriculture) from March 2015 to December 2017.	2020
Randy Limbacher Houston, Texas U.S.A.	CEO, Meridian Energy, LLC (Meridian) (oil and gas exploration and production) since June 2017. Executive Vice-President of Strategy of Alta Mesa Resources, Inc. (Alta Mesa) (oil and gas, exploration and production) from September 2019 to May 2020. Director, CARBO Ceramics Inc. (CARBO) from July 2007 to July 2020. Interim President, Alta Mesa from January to September 2019. Vice Chairman and director, Samson Resources Corporation (Samson) (oil and gas exploration and production) from December 2015 to March 2017.	2018
John E. Lowe Houston, Texas U.S.A.	Non-executive Chair of the Board, Apache Corporation (Apache) (oil and gas) since May 2015. Director, Apache since July 2013. Director, Phillips 66 Company (energy infrastructure) since May 2012. 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[5]	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. Senior Vice-President, Strategy and Corporate Development (Corporate Services Division), TCPL from October 2015 to January 2017.	2021
Una Power Vancouver, British Columbia Canada	Corporate director. Director, Teck Resources Limited (Teck) (diversified mining) since April 2017. Director, The Bank of Nova Scotia (Scotiabank) (chartered bank) since April 2016. Director, Kinross Gold Corporation (gold producer) from April 2013 to May 2019. Director, Nexen Energy ULC (Nexen) (oil and gas, exploration and production) from February 2013 to March 2016.	2019
Mary Pat Salomone Naples, Florida U.S.A.	Corporate director. Director, Intertape Polymer Group (manufacturing) since November 2015. 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, Stelco Holdings Inc. (manufacturing) since May 2018. Director, Magna International Inc. (automotive manufacturing) since May 2014 and Scotiabank (chartered bank) since May 2008. Member, selection panel for Canada's outstanding CEO since 2013.	2016
D. Michael G. Stewart Calgary, Alberta Canada	Corporate director. Director, Bonterra Energy Corporation (Bonterra) (oil and gas, exploration and production) since March 2021. Director, Pengrowth Energy Corporation (Pengrowth) (oil and gas, exploration and production) from December 2010 to January 2020. Director, CES Energy Solutions Corp. (CES Energy) (oilfield services) from January 2010 to June 2019.	2006
Siim A. Vanaselja Toronto, Ontario Canada	Corporate director. Chair of the Board, TC Energy since May 2017. Director, Power Corporation (financial services) since May 2020. Director, Power Financial Corporation (financial services) since May 2018. Director, RioCan Real Estate Investment Trust (real estate) since May 2017. Director, Great-West Lifeco Inc. (financial services) since May 2014. Director, Maple Leaf Sports and Entertainment Ltd. (sports, property management) from August 2012 to June 2017.	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) since 2015. Director, Royal Bank of Canada (RBC) (chartered bank) since 2015. Member, International Advisory Board of École des Hautes Etudes Commerciales Montréal since October 2017.	2017

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.

[5] 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.

In September 2019, Alta Mesa and six affiliated debtors each filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas. In conjunction with the bankruptcy, Alta Mesa was subsequently delisted from NASDAQ in September 2019. Mr. Limbacher was Interim President of Alta Mesa from January to September 2019 and was Executive Vice-President of Strategy from September 2019 to May 2020.

In March 2020, CARBO filed a voluntary petition for reorganization under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas. As part of the process, the company entered into an agreement with Wilks Brothers, LLC (Wilks Brothers) and Equify Financial, LLC under which Wilks Brothers acquired CARBO through a debt-for-equity exchange in July 2020. Mr. Limbacher was a director of CARBO from July 2007 to July 2020.

Samson filed a plan of reorganization in Delaware Bankruptcy Court in September 2015. Mr. Limbacher was the CEO of Samson from 2013 through 2015 and remained a director of Samson until it emerged from bankruptcy in March 2017.

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 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 14, 2022, 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
Stéphan Crétier		ü		ü
Michael R. Culbert	ü		ü	
William D. Johnson	ü			ü
Susan C. Jones	ü			ü
Randy Limbacher	ü		ü	
John E. Lowe		Chair	ü	
David MacNaughton		ü	ü	
Una Power	Chair		ü	
Mary Pat Salomone		ü	Chair	
Indira Samarasekera		ü		ü
D. Michael G. Stewart	ü			ü
Siim A. Vanaselja (Chair)		ü		ü
Thierry Vandal	ü			Chair

OFFICERS

With the exception of Stanley G. Chapman, III, Corey N. Hessen and Patrick C. Muttart, 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. Prior to February 2017, Senior Vice-President, Strategy and Corporate Development (Corporate Services Division).
Stanley G. Chapman, III Texas, U.S.A.	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. Prior to April 2017, Senior Vice-President and General Manager, U.S. Natural Gas Pipelines (Natural Gas Pipelines Division).
Dawn E. de Lima	Executive Vice-President, Corporate Services	Prior to December 2020, Chief Shared Services Officer, TransAlta Corporation (TransAlta). Prior to February 2019, Chief Officer, Business and Operational Services, TransAlta. Prior to July 2018, Chief Administrative Officer, TransAlta.
Corey N. Hessen Maryland, U.S.A.	Executive Vice-President and President, Power, Storage and Origination	Prior to January 2022, Senior Vice-President and President, Power and Storage. Prior to January 2021, Senior Vice-President, Power & Storage (Power and Storage Division). Prior to September 2020, Senior Vice-President, Fuels, Exelon Corporation.
Joel E. Hunter	Executive Vice-President and Chief Financial Officer	Prior to August 2021, Senior Vice-President, Capital Markets. Prior to December 2017, Vice-President, Finance and Treasurer.
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)). Prior to April 2017, Vice-President, Commercial West (Natural Gas Pipelines Division).
Jawad A. Masud	Senior Vice-President, Technical Centre	Prior to January 2022, Senior Vice-President, Operations and Project Execution (Natural Gas Pipelines Division (Canada)). Prior to April 2020, Vice-President, Commercial Services, Optimization & Design (Natural Gas Pipelines Division (Canada)). Prior to February 2018, Director, Commercial West Markets, Industry Collaboration and Rates.
Patrick C. Muttart Texas, U.S.A.	Senior Vice-President, Stakeholder Relations	Prior to September 2021, Director External Affairs, PMI Global Services.
Tracy A. Robinson	Executive Advisor	Prior to January 2022, Executive Vice-President and President, Canadian Natural Gas Pipelines. Prior to January 2019, Executive Vice-President, Canadian Natural Gas Pipelines. Prior to September 2018, Senior Vice-President, Canadian Natural Gas Pipelines. Prior to November 2017, Senior Vice-President, Canada (Natural Gas Pipelines Division (Canada)). Prior to April 2017, Senior Vice-President, Canada (Natural Gas Pipelines Division). Prior to March 2017, Vice-President, Supply Chain (Corporate Services Division).
Bevin M. Wirzba	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
Gloria L. Hartl	Vice-President, Risk Management	Prior to February 2019, Director, Corporate Planning. Prior to December 2017, Manager, Short-Term Planning & Forecasting.
Dennis P. Hebert	Vice-President, Taxation	Prior to June 2017, Vice-President, Tax and Insurance, Spectra Energy.
Jonathan E. Wrathall	Vice-President, Finance and Evaluations	Prior to July 2021, Director, Capital Markets. Prior to December 2020, Director, Corporate Planning. Prior to March 2019, Senior Manager, Capital Markets.
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. Prior to December 2017, Director, Corporate Planning and Evaluations.
Christine R. Johnston	Vice-President, Law and Corporate Secretary	Vice-President, Law and Corporate Secretary.
G. Glenn Menuz	Vice-President and Controller	Vice-President and Controller.

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 executive leadership team must receive Governance Committee consent for all outside business activities.

Under COBE, directors must also declare any material interest that he or she 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 2021.

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 our 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 Governance Committee. All other employees must receive the consent of the Corporate Secretary or his or her 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 internal 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 14, 2022 are Una Power (Chair), Michael R. Culbert, William D. Johnson, Susan C. Jones, Randy Limbacher, D. Michael G. Stewart and Thierry Vandal.

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 and Mr. Vandal are *Audit Committee Financial Experts* as that term is defined under U.S. securities laws. The Board has made these determinations 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 also serves on the board of directors and as audit committee Chair for both Teck and Scotiabank. Ms. Power was previously the Chief Financial Officer of Nexen, 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.

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 where he was also a member of the audit committee. He was a director and Vice Chair of PETRONAS, director and President of PNW LNG LP and former co-founder, director, President and CEO of Progress Energy.

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 ARC and was a member of the audit and finance committee of Seven Generations Energy Ltd. prior to its merger with ARC. She also serves as a director of Piedmont Lithium Limited. 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.

Randy Limbacher

Mr. Limbacher holds a Bachelor of Science degree from Louisiana State University. He is currently the CEO of Meridian. Mr. Limbacher previously served on the board of directors and audit committee for CARBO and was the Executive Vice-President and Interim President of Alta Mesa. He was previously the Chairman, President and CEO of Rosetta Resources, Inc. and President, CEO and Vice Chairman of Samson.

D. Michael G. Stewart

Mr. Stewart earned a Bachelor of Science in Geological Sciences with First Class Honours from Queen's University. He currently serves on the board of directors of Bonterra and is a member of its audit committee. He previously served as a director of Pengrowth and CES Energy. He has also previously served on the board of directors of several other public companies and organizations and was on the audit committee and Chair of the audit committee of certain of those boards. Mr. Stewart held a number of senior executive positions with Westcoast Energy Inc. including Executive Vice-President, Business Development.

Thierry Vandal

Mr. Vandal earned a Bachelor of Engineering degree from École Polytechnique de Montréal and a Master of Business Administration in Finance from the École des Hautes Etudes Commerciale Montréal. He is the President of Axium U.S. and serves on the board of directors for Axium and on the international advisory boards of École des Hautes Études Commerciale Montréal and McGill University. He also serves on the board of directors for RBC where he was previously designated as RBC's audit committee's financial expert. Mr. Vandal previously served on the audit committee for Veresen Inc. and has over nine years' experience of serving with Hydro-Québec where he also held the position of President and CEO.

PRE-APPROVAL POLICIES AND PROCEDURES

TC Energy's Audit Committee has adopted a pre-approval policy with respect to permitted non-audit services. Under the policy, the Audit Committee has granted pre-approval for specified non-audit services. For 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 engagements of $250,000 or more, pre-approval of the Audit Committee is required. In all cases, regardless of the dollar amount involved, where there is a potential for a conflict of interest involving the external auditor to arise on an engagement, the Audit Committee must pre-approve the assignment.

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)	2021	2020
Audit fees	**12.3**	12.8
• 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	**0.2**	0.2
• French translation services		
• services related to the audit of the financial statements of TC Energy pipeline abandonment trusts and certain post-retirement plans		
Tax fees	**0.9**	1.1
• Canadian and international tax planning and tax compliance matters, including the review of income tax returns and other tax filings		
All other fees	**0.1**	—
• ESG advisory services		
Total fees	**13.5**	14.1

Legal proceedings and regulatory actions

Legal proceedings, arbitrations and actions are part of doing business. While we cannot predict the final outcomes of proceedings and actions with certainty, management does not expect any current or potential proceeding or action to have a material impact on our consolidated financial position or results of operations.

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, Halifax 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, 2021, nor has it entered into any material contracts outside the ordinary course of business prior to the year ended December 31, 2021 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.sedar.com).
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

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

ATM	An at-the-market program allowing us to issue common shares from treasury at the prevailing market price
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, 2021

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)
CBCA	*Canada Business Corporations Act*
CER	Canadian Energy Regulator (formerly the National Energy Board (Canada))
CFE	Comisión Federal de Electricidad (Mexico)
CRE	Comisión Reguladora de Energía (Mexico)
DOS	U.S. Department of State
FERC	Federal Energy Regulatory Commission (U.S.)
IESO	Independent Electricity System Operator
NEB	National Energy Board (Canada)
NYSE	New York Stock Exchange
OGC	Oil and Gas Commission (British Columbia)
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.

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; and

   (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; and

(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; and

(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; and

(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; and

(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 for independent 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 14, 2022

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, 2021.

This MD&A should also be read in conjunction with our December 31, 2021 audited Consolidated financial statements and notes for the same period, which have been prepared in accordance with U.S. GAAP.

Contents

About this document

Throughout this MD&A, the terms we, us, our and TC Energy mean TC Energy Corporation and its subsidiaries. Abbreviations and acronyms that are not defined in the document are defined in the glossary on page 120. All information is as of February 14, 2022 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, including portfolio management
- expected dividend growth
- expected access to and cost of capital
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures, contractual obligations, commitments and contingent liabilities
- 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
- the expected impact of future tax and accounting changes
- expected industry, market and economic conditions
- the expected impact of COVID-19.

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 and energy transition
- regulatory decisions and outcomes
- planned and unplanned outages and the use of our pipeline, 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
- inflation rates and commodity prices
- interest, tax and foreign exchange rates
- nature and scope of hedging
- expected impact of COVID-19.

Risks and uncertainties

- realization of expected benefits from acquisitions and divestitures
- our ability to successfully implement our strategic priorities and whether they will yield the expected benefits
- our ability to implement a capital allocation strategy aligned with maximizing shareholder value
- the operating performance of our pipeline, power and storage assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the amount of capacity payments and revenues from our power generation assets due to plant availability
- production levels within supply basins
- construction and completion of capital projects
- cost and availability of labour, equipment and materials
- the 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 and COVID-19
- our ability to realize the value of tangible assets and contractual recoveries, including those specific to the Keystone XL pipeline project
- competition in the businesses in which we operate
- unexpected or unusual weather
- acts of civil disobedience
- cyber security and technological developments
- ESG 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, including COVID-19 and the unexpected 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.sedar.com).

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.

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 and comparable earnings before interest, taxes, depreciation and amortization (comparable EBITDA) are consistent with the factors that impact net income attributable to common shares and segmented earnings, respectively, 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
- certain fair-value adjustments relating to risk management activities
- legal, contractual and bankruptcy settlements
- impairment of goodwill, plant, property and equipment, investments and other assets
- acquisition and integration costs
- restructuring costs.

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. As a result, the 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. We also exclude from comparable measures the unrealized foreign exchange gains and losses on the loan receivable from affiliate as well as the corresponding proportionate share of Sur de Texas foreign exchange gains and losses, as these amounts do not accurately reflect the gains and losses that will 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
comparable EBIT	segmented earnings
comparable earnings	net income attributable to common shares
comparable earnings per common share	net income per common share
funds generated from operations	net cash provided by operations
comparable funds generated from operations	net cash provided by operations

Comparable EBITDA and comparable EBIT

Comparable EBITDA represents segmented earnings adjusted for certain specific items, excluding non-cash 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 earnings before interest and taxes (comparable EBIT) represents segmented earnings 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.

Comparable earnings and comparable earnings per common share

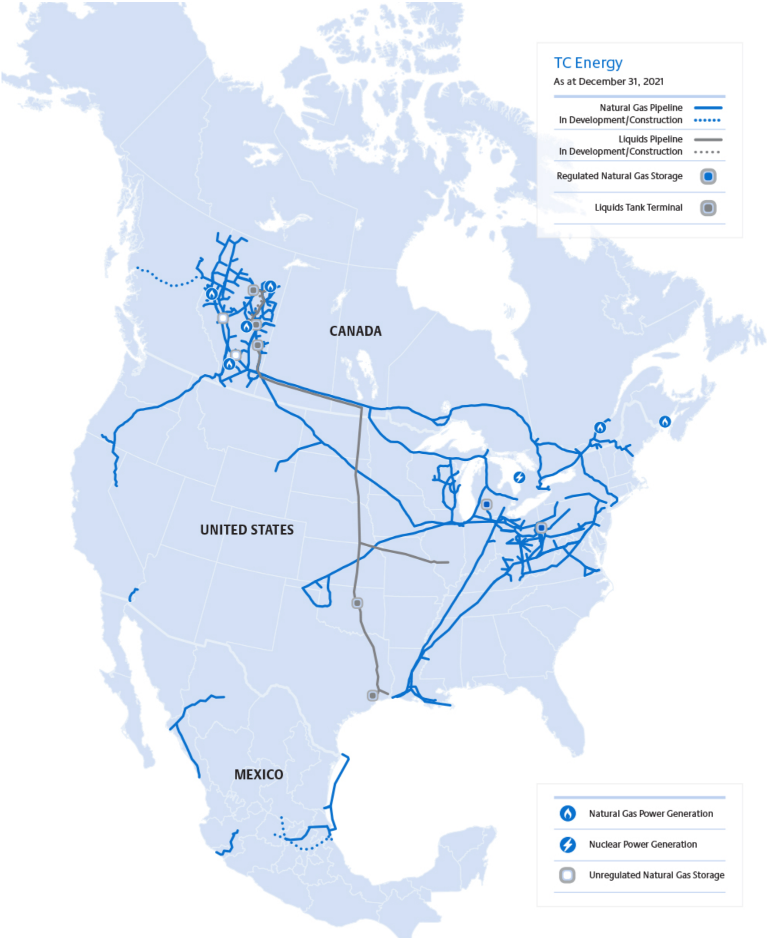
Comparable earnings represents earnings attributable to common shareholders on a consolidated basis, adjusted for specific items. Comparable earnings is comprised of segmented earnings, Interest expense, AFUDC, Interest income and other, Income tax expense, Non-controlling interests and Preferred share dividends, adjusted for specific items. Refer to the Financial highlights section for reconciliations to Net income attributable to common shares and Net income 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 (working capital). The components of changes in working capital are disclosed in Note 27, Changes in operating working capital, of our 2021 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.

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 Storage. 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 Storage. 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 $)	2021	2020
Total assets by segment		
Canadian Natural Gas Pipelines	**25,213**	22,852
U.S. Natural Gas Pipelines	**45,502**	43,217
Mexico Natural Gas Pipelines	**7,547**	7,215
Liquids Pipelines	**14,951**	16,744
Power and Storage	**6,563**	5,062
Corporate	**4,442**	5,210
	104,218	100,300

year ended December 31 (millions of $)	2021	2020
Total revenues by segment		
Canadian Natural Gas Pipelines	**4,519**	4,469
U.S. Natural Gas Pipelines	**5,233**	5,031
Mexico Natural Gas Pipelines	**605**	716
Liquids Pipelines	**2,306**	2,371
Power and Storage	**724**	412
	13,387	12,999

year ended December 31 (millions of $)	2021	2020
Comparable EBITDA by segment[1]		
Canadian Natural Gas Pipelines	**2,675**	2,566
U.S. Natural Gas Pipelines	**3,856**	3,638
Mexico Natural Gas Pipelines	**666**	786
Liquids Pipelines	**1,526**	1,700
Power and Storage	**683**	677
Corporate	**(24)**	(16)
	9,382	9,351

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, focused on transporting and delivering the energy people need every day. Our goal is to develop and build a portfolio of infrastructure assets that will enable us to prosper irrespective of the pace and direction of energy transition.

Our business consists of natural gas and crude oil transportation, storage and delivery systems in addition to power generation assets that produce electricity. These long-life infrastructure assets cover strategic North American corridors and are supported by long-term commercial arrangements and/or rate regulation, generating predictable and sustainable cash flows and earnings, the cornerstones of our low-risk 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
- crude oil will remain an important part of the fuel mix
- the need for renewables along with reliable, on-demand energy sources to support grid stability will grow significantly
- the value of existing infrastructure assets will become more valuable given the challenges to develop new greenfield, linear-energy infrastructure, in particular, pipelines.

These beliefs drive our capital allocation framework and we will seek to intentionally migrate our portfolio composition over time.

Allocation of comparable EBITDA[1]

year ended December 31	2021
Comparable EBITDA by segment	
Canadian Natural Gas Pipelines	**29 %**
U.S. Natural Gas Pipelines	**41 %**
Mexico Natural Gas Pipelines	**7 %**
Liquids Pipelines	**16 %**
Power and Storage	**7 %**
	100 %

1 Refer to Note 4, Segmented information, of our 2021 Consolidated financial statements for an allocation of segmented earnings by business segment.

Future investments will alter our business mix as energy transition unfolds with the following anticipated shifts in capital allocation:

- Power and Storage weighting in our portfolio is expected to grow
- Natural Gas Pipelines will continue to attract capital
- Liquids Pipelines investment will be targeted and tied to maximizing the value of our asset base
- Measured investment in new technology without taking significant commodity price or volumetric risk.

Key components of our strategy, set out below, support our ability to be competitive, responsible and innovative, enhance the value proposition for our shareholders and safely deliver the energy people need today and in the future.

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 $24 billion in secured projects. As well, our noted projects under development are, or are expected to be, largely commercially supported. These investments will contribute to incremental earnings and cash flows as they are placed in service
- Our existing extensive footprint offers significant in-corridor growth opportunities. This includes possible future opportunities to deploy low-emissions infrastructure technologies such as renewables, hydrogen and carbon capture, which will help reduce our and our customers' carbon footprint and also supports extending the longevity of our existing assets
- We continue 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 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 ESG 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, enhances future resilience under a changing energy mix, and diversifies access to attractive supply and market regions within our risk preferences. Refer to the Enterprise risk management section for an overview of our enterprise risks
- We focus on commercially 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 energy transition growth initiatives, to full development and construction when market conditions are appropriate and project risks and returns are acceptable
- We monitor trends specific to energy supply and demand fundamentals, in addition to analyzing how our portfolio performs under different energy mix scenarios considering the recommendations of the Financial Stability Board's Task Force on Climate-related Financial Disclosures. 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 and ESG 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. A strong focus on talent management ensures that we have the necessary capabilities to execute and deliver on our strategy.

Our competitive advantage

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, 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: our low-risk and enduring business model offers the scale and presence to provide essential and highly competitive infrastructure services that enable us to maximize the full-life value of our long-life assets and commercial positions throughout all points of the business cycle. Our portfolio of assets support transporting both molecules and electrons, providing us flexibility to allocate capital towards electrification or other emerging low-carbon technologies in support of any energy transition scenario

- disciplined operations: our values-centred 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 investment balanced with common share dividend growth while preserving financial flexibility to fund our operations in all market conditions. 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 and re-purposing the underutilized Canadian Mainline pipeline capacity from natural gas to crude oil service
- commitment to sustainability and ESG: 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. The 2021 Report on Sustainability builds on our commitment to establishing clear metrics and targets for 10 sustainability commitments from last year. We have also committed to reduce GHG emissions intensity from our operations by 30 per cent by 2030 and position us to achieve zero emissions from our operations, on a net basis, by 2050
- open communication: we carefully manage relationships with our customers and stakeholders and offer clear, candid communication of our prospects 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 portfolio management to finance new initiatives. Reserve common equity issuances for transformational opportunities.
Known and acceptable project risks
• Select investments with known, acceptable and manageable project execution risk, including stakeholder considerations.
Business underpinned by strong fundamentals
• Invest in assets that are investment-grade on a stand-alone basis with stable cash flows supported by strong underlying macroeconomic fundamentals, conducive regulation 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.

2021 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 22 and 82 as well as the business segment Financial results sections for reconciliations to the most directly comparable GAAP measures.

year ended December 31 (millions of $, except per share amounts)	**2021**	**2020**	**2019**
Income			
Revenues	**13,387**	12,999	13,255
Net income attributable to common shares	**1,815**	4,457	3,976
per common share – basic	**$1.87**	$4.74	$4.28
Comparable EBITDA[1]	**9,382**	9,351	9,366
Comparable earnings	**4,153**	3,945	3,851
per common share	**$4.27**	$4.20	$4.14
Cash flows			
Net cash provided by operations	**6,890**	7,058	7,082
Comparable funds generated from operations	**7,406**	7,385	7,117
Capital spending[2]	**7,134**	8,900	8,784
Proceeds from sales of assets, net of transaction costs	**35**	3,407	2,398
Balance sheet[3]			
Total assets	**104,218**	100,300	99,279
Long-term debt, including current portion	**38,661**	36,885	36,985
Junior subordinated notes	**8,939**	8,498	8,614
Redeemable non-controlling interest[4]	**—**	393	—
Preferred shares	**3,487**	3,980	3,980
Non-controlling interests	**125**	1,682	1,634
Common shareholders' equity	**29,784**	27,418	26,783
Dividends declared			
per common share	**$3.48**	$3.24	$3.00
Basic common shares (millions)			
– weighted average for the year	**973**	940	929
– issued and outstanding at end of year	**981**	940	938

1 Additional information on Segmented earnings, the most directly comparable GAAP measure, can be found on page 20.
2 Includes Capital expenditures, Capital projects in development and Contributions to equity investments. Refer to Note 4, Segmented information, of our 2021 Consolidated financial statements for the financial statement line items that comprise total capital spending.
3 As at December 31.
4 At December 31, 2020, redeemable non-controlling interest was classified in mezzanine equity and subsequently repurchased in 2021.

Consolidated results

year ended December 31 (millions of $, except per share amounts)	2021	2020	2019
Canadian Natural Gas Pipelines	**1,449**	1,657	1,115
U.S. Natural Gas Pipelines	**3,071**	2,837	2,747
Mexico Natural Gas Pipelines	**557**	669	490
Liquids Pipelines	**(1,600)**	1,359	1,848
Power and Storage	**628**	181	455
Corporate	**(46)**	70	(70)
Total segmented earnings	**4,059**	6,773	6,585
Interest expense	**(2,360)**	(2,228)	(2,333)
Allowance for funds used during construction	**267**	349	475
Interest income and other	**200**	213	460
Income before income taxes	**2,166**	5,107	5,187
Income tax expense	**(120)**	(194)	(754)
Net income	**2,046**	4,913	4,433
Net income attributable to non-controlling interests	**(91)**	(297)	(293)
Net income attributable to controlling interests	**1,955**	4,616	4,140
Preferred share dividends	**(140)**	(159)	(164)
Net income attributable to common shares	**1,815**	4,457	3,976
Net income per common share – basic	**$1.87**	$4.74	$4.28

Net income attributable to common shares in 2021 was $1.8 billion or $1.87 per share (2020 – $4.5 billion or $4.74 per share; 2019 – $4.0 billion or $4.28 per share), a decrease of $2.6 billion or $2.87 per share compared to the same period in 2020 primarily due to the $2.1 billion after-tax asset impairment of the Keystone XL pipeline project, net of expected contractual recoveries and other contractual and legal obligations recorded in 2021. The decrease in Net income per common share in 2021 also reflects the impact of common shares issued for the acquisition of the remaining ownership interests in TC PipeLines, LP. The increase in Net income per common share in 2020 of $0.46 per share compared to 2019 reflected higher net income in 2020 and the dilutive impact of common shares issued under our DRP in 2019.

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

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 20, 2021 revocation of the Presidential Permit. Refer to the Liquids Pipelines – Significant events section for additional information
- a $48 million after-tax expense with respect to transition payments incurred as part of the Voluntary Retirement Program (VRP)
- preservation and storage 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 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.

The Keystone XL pipeline project asset impairment charge does not reflect offsetting amounts with respect to the Government of Alberta's investment in Keystone XL nor their repayment of the project's guaranteed credit facility without recourse to TC Energy, both of which were accounted for within the Consolidated statement of equity in 2021 and served to reduce our net financial impact from the Keystone XL pipeline project termination. Refer to the Liquids Pipelines – Significant events section for additional information.

2020

- an after-tax loss of $283 million related to the Ontario natural gas-fired power plants sold in April 2020. The total after-tax loss on this transaction to the end of 2020 was $477 million including losses accrued in 2019 upon classification of the assets as held for sale
- an after-tax gain of $402 million related to the sale of a 65 per cent equity interest in Coastal GasLink Pipeline Limited Partnership (Coastal GasLink LP)
- an income tax valuation allowance release of $299 million following our reassessment of deferred tax assets that were deemed more likely than not to be realized in 2020
- an additional $18 million income tax recovery related to state income taxes on the sale of certain Columbia Midstream assets.

2019

- an after-tax gain of $115 million related to the sale of an 85 per cent equity interest in Northern Courier
- an after-tax loss of $194 million related to the Ontario natural gas-fired power plant assets held for sale
- an income tax valuation allowance release of $195 million related to certain prior years' U.S. income tax losses resulting from our reassessment of deferred tax assets that were deemed more likely than not to be realized
- an after-tax loss of $152 million related to the sale of certain Columbia Midstream assets in 2019
- an after-tax gain of $54 million related to the sale of the Coolidge generating station
- a deferred income tax benefit of $32 million related to the impact of an Alberta corporate income tax rate reduction on our Canadian businesses not subject to RRA
- an after-tax loss of $6 million related to the sale of the remainder of our U.S. Northeast power marketing contracts.

Refer to the Financial results sections in each business segment and the Financial condition section of this MD&A for further discussion of these highlights.

Net income in all periods included unrealized gains and losses from changes in risk management activities which we exclude, along with the above noted items, to arrive at comparable earnings. A reconciliation of Net income attributable to common shares to comparable earnings is shown in the following table.

Reconciliation of net income to comparable earnings

year ended December 31 (millions of $, except per share amounts)	2021	2020	2019
Net income attributable to common shares	**1,815**	4,457	3,976
Specific items (net of tax):			
Keystone XL asset impairment charge and other	**2,134**	—	—
Voluntary Retirement Program	**48**	—	—
Keystone XL preservation and other	**37**	—	—
Gain on sale of Northern Courier	**(19)**	—	(115)
(Gain)/loss on sale of Ontario natural gas-fired power plants	**(7)**	283	194
Gain on partial sale of Coastal GasLink LP	**—**	(402)	—
Income tax valuation allowance releases	**—**	(299)	(195)
(Gain)/loss on sale of Columbia Midstream assets	**—**	(18)	152
Gain on sale of Coolidge generating station	**—**	—	(54)
Alberta corporate income tax rate reduction	**—**	—	(32)
U.S. Northeast power marketing contracts	**—**	—	6
Risk management activities[1]	**145**	(76)	(81)
Comparable earnings	**4,153**	3,945	3,851
Net income per common share	**$1.87**	$4.74	$4.28
Keystone XL asset impairment charge and other	**2.19**	—	—
Voluntary Retirement Program	**0.05**	—	—
Keystone XL preservation and other	**0.04**	—	—
Gain on sale of Northern Courier	**(0.02)**	—	(0.12)
(Gain)/loss on sale of Ontario natural gas-fired power plants	**(0.01)**	0.30	0.21
Gain on partial sale of Coastal GasLink LP	**—**	(0.43)	—
Income tax valuation allowance releases	**—**	(0.32)	(0.21)
(Gain)/loss on sale of Columbia Midstream assets	**—**	(0.02)	0.16
Gain on sale of Coolidge generating station	**—**	—	(0.06)
Alberta corporate income tax rate reduction	**—**	—	(0.03)
U.S. Northeast power marketing contracts	**—**	—	0.01
Risk management activities	**0.15**	(0.07)	(0.10)
Comparable earnings per common share	**$4.27**	$4.20	$4.14

1

year ended December 31 (millions of $)	2021	2020	2019
U.S. Natural Gas Pipelines	**6**	—	—
Liquids Pipelines	**(3)**	(9)	(72)
Canadian Power	**12**	(2)	—
U.S. Power	**—**	—	(52)
Natural Gas Storage	**(6)**	(13)	(11)
Foreign exchange	**(203)**	126	245
Income taxes attributable to risk management activities	**49**	(26)	(29)
Total unrealized (losses)/gains from risk management activities	**(145)**	76	81

Comparable EBITDA to comparable earnings

Comparable EBITDA represents segmented earnings adjusted for the specific items described above and excludes non-cash 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)	2021	2020	2019
Comparable EBITDA			
Canadian Natural Gas Pipelines	**2,675**	2,566	2,274
U.S. Natural Gas Pipelines	**3,856**	3,638	3,480
Mexico Natural Gas Pipelines	**666**	786	605
Liquids Pipelines	**1,526**	1,700	2,192
Power and Storage	**683**	677	832
Corporate	**(24)**	(16)	(17)
Comparable EBITDA	**9,382**	9,351	9,366
Depreciation and amortization	**(2,522)**	(2,590)	(2,464)
Interest expense included in comparable earnings	**(2,354)**	(2,228)	(2,333)
Allowance for funds used during construction	**267**	349	475
Interest income and other included in comparable earnings	**444**	173	162
Income tax expense included in comparable earnings	**(833)**	(654)	(898)
Net income attributable to non-controlling interests	**(91)**	(297)	(293)
Preferred share dividends	**(140)**	(159)	(164)
Comparable earnings	**4,153**	3,945	3,851
Comparable earnings per common share	**$4.27**	$4.20	$4.14

Comparable EBITDA – 2021 versus 2020

Comparable EBITDA in 2021 increased by $31 million compared to 2020 primarily due to the net result of the following:

- increased earnings in U.S. Natural Gas Pipelines from higher Columbia Gas transportation rates effective February 1, 2021 as a result of the subsequently uncontested rate case settlement, improved earnings across our U.S. Natural Gas Pipelines assets following the cold weather events of 2021 impacting many of the U.S. markets in which we operate, increased earnings from our mineral rights business and increased capitalization of pipeline integrity costs, partially offset by higher property taxes
- higher comparable EBITDA from Canadian Natural Gas Pipelines largely as a result of the impact of increased flow-through depreciation and income taxes along with higher rate-base earnings on the NGTL System, full-year recognition of Coastal GasLink development fee revenue and higher Canadian Mainline incentive earnings and flow-through income taxes, partially offset by lower flow-through depreciation and financial charges
- consistent Power and Storage results mainly attributable to increased Canadian Power earnings primarily due to higher realized margins in 2021, contributions from trading activities and a full of year of earnings from our MacKay River cogeneration facility following its return to service in May 2020, partially offset by the sale of our Ontario natural gas-fired power plants in April 2020 and decreased earnings at Bruce Power in 2021 due to lower volumes resulting from greater planned outage days and higher operating expenses
- decreased earnings from Liquids Pipelines attributable to lower volumes on the U.S. Gulf Coast section of the Keystone Pipeline System, partially offset by increased contributions from liquids marketing activities reflecting higher margins and volumes
- lower contribution from Mexico Natural Gas Pipelines mainly due to US$55 million of fees recognized in 2020 associated with the successful completion of the Sur de Texas pipeline
- foreign exchange impact of a weaker U.S. dollar on the Canadian dollar equivalent segmented earnings in our U.S. dollar-denominated operations. As detailed on page 25, U.S. dollar-denominated comparable EBITDA of US$4.6 billion increased by US$226 million compared to 2020; however, this was translated at 1.25 in 2021 versus 1.34 in 2020. Refer to the Foreign exchange discussion below for additional information.

While the weakening of the U.S. dollar in 2021 compared to 2020 had a considerable negative impact on 2021 comparable EBITDA, the corresponding impact on comparable earnings was not significant due to offsetting natural and economic hedges. Refer to the Foreign exchange discussion below for additional information.

Comparable EBITDA – 2020 versus 2019

Comparable EBITDA in 2020 decreased by $15 million compared to 2019 primarily due to the net result of the following:

- decreased earnings from Liquids Pipelines as a result of lower volumes on the Keystone Pipeline System, reduced contributions from liquids marketing activities and the July 2019 sale of an 85 per cent equity interest in Northern Courier
- lower Power and Storage results mainly attributable to decreased Bruce Power results in 2020 primarily due to the net impact of lower overall plant generation with the commencement of the Unit 6 MCR program in January 2020, partially offset by fewer outage days on the remaining units and a higher realized power price. As well, reduced earnings in Canadian Power in 2020 were largely as a result of the sale of our Ontario natural gas-fired power plants in April 2020 and the May 2019 sale of our Coolidge generating station
- higher comparable EBITDA from Canadian Natural Gas Pipelines primarily due to the impact of increased rate-base earnings and flow-through depreciation from additional facilities placed in service as well as higher flow-through financial charges on the NGTL System, plus Coastal GasLink development fee revenue recognized in 2020, partially offset by lower flow-through income taxes on the NGTL System and the Canadian Mainline
- increased contribution from Mexico Natural Gas Pipelines mainly due to higher earnings from our investment in the Sur de Texas pipeline following its September 2019 in-service. This includes revenues of US$55 million recognized in 2020 related to fees associated with our successful completion of the Sur de Texas pipeline
- incremental earnings in U.S. Natural Gas Pipelines from Columbia Gas and Columbia Gulf growth projects placed in service and from ANR due to the sale of natural gas from certain gas storage facilities, partially offset by decreased earnings as a result of the sale of certain Columbia Midstream assets in August 2019
- foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent segmented earnings in our U.S. dollar-denominated operations. As detailed on page 25, U.S. dollar-denominated comparable EBITDA of US$4.3 billion decreased by US$174 million compared to 2019; however, this was translated at 1.34 in 2020 versus 1.33 in 2019. Refer to the Foreign exchange discussion below for additional information.

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

Comparable earnings – 2021 versus 2020

Comparable earnings in 2021 were $208 million or $0.07 per common share higher than in 2020, and were primarily the net result of:

- changes in comparable EBITDA described above
- higher Interest income and other mainly attributable to realized gains in 2021 compared to realized losses in 2020 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- decreased Non-controlling interests following the March 3, 2021 acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy
- lower Depreciation and amortization on our U.S. dollar-denominated assets primarily as a result of the weaker U.S. dollar and in Canadian Natural Gas Pipelines due to one section of the Canadian Mainline being fully depreciated in 2021
- higher Income tax expense mainly due to increased pre-tax earnings and higher flow-through income taxes on our Canadian rate-regulated pipelines
- higher Interest expense primarily due to lower capitalized interest as a result of its cessation for the Keystone XL pipeline project following the revocation of the Presidential Permit on January 20, 2021, the change to equity accounting for our Coastal GasLink investment upon the sale of a 65 per cent interest in Coastal GasLink LP and the completion of the Napanee power plant in 2020, partially offset by the foreign exchange impact from a weaker U.S. dollar on translation of U.S. dollar-denominated interest
- lower AFUDC, predominantly due to the suspension of recording AFUDC on the Villa de Reyes project effective January 1, 2021 as a result of ongoing project delays, partially offset by the NGTL System and U.S. natural gas pipeline expansion projects.

Comparable earnings – 2020 versus 2019

Comparable earnings in 2020 were $94 million or $0.06 per common share higher than in 2019, and were primarily the net result of:

- changes in comparable EBITDA described above
- a decrease in Income tax expense mainly due to lower flow-through income taxes on Canadian rate-regulated pipelines and the impact of higher foreign tax rate differentials
- lower Interest expense as a result of higher capitalized interest largely related to Keystone XL, net of the impact of Napanee completing construction in 2020 and lower interest rates on reduced levels of short-term borrowings. These were partially offset by the effect of long-term debt issuances, net of maturities, as well as the foreign exchange impact from a stronger U.S. dollar on the translation of U.S. dollar-denominated interest
- a decrease in AFUDC predominantly due to NGTL System expansion projects placed in service and the suspension of recording AFUDC on the Tula project resulting from continued construction delays, partially offset by further construction of the Villa de Reyes pipeline
- higher Depreciation and amortization largely in Canadian Natural Gas Pipelines and U.S. Natural Gas Pipelines reflecting new assets placed in service. In Canadian Natural Gas Pipelines, as it is fully recovered in tolls on a flow-through basis, it has no significant impact on comparable earnings.

Comparable earnings per share reflects the impact of common shares issued for the acquisition of the remaining ownership interests in TC PipeLines, LP on March 3, 2021 and under our DRP in 2019. Refer to the Financial condition section for further information on common share issuances.

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. Despite the significant change in the average exchange rate in 2021 compared to 2020, the net impact of U.S. dollar movements on comparable earnings over this period, 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. 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$)	**2021**	**2020**	**2019**
Comparable EBITDA			
U.S. Natural Gas Pipelines	**3,075**	2,714	2,623
Mexico Natural Gas Pipelines[1]	**602**	666	568
U.S. Liquids Pipelines	**884**	955	1,318
	4,561	4,335	4,509
Depreciation and amortization	**(911)**	(877)	(847)
Interest on long-term debt and junior subordinated notes	**(1,259)**	(1,302)	(1,326)
Capitalized interest on capital expenditures	**10**	131	34
Allowance for funds used during construction	**101**	182	205
Non-controlling interests and other	**(76)**	(248)	(233)
	2,426	2,221	2,342
Average exchange rate – U.S. to Canadian dollars	**1.25**	1.34	1.33

1 Excludes interest expense on our inter-affiliate loan with Sur de Texas which is fully offset in Interest income and other.

Cash flows

Net cash provided by operations of $6.9 billion in 2021 was two per cent lower than 2020 due to lower funds generated from operations, partially offset by the amount and timing of working capital changes. Comparable funds generated from operations of $7.4 billion in 2021 was consistent with 2020 and reflected higher comparable earnings, partially offset by fees collected in 2020 associated with the construction of the Sur de Texas pipeline, as well as lower distributions from the operating activities of our equity investments.

Funds used in investing activities

Capital spending[1]

year ended December 31 (millions of $)	2021	2020	2019
Canadian Natural Gas Pipelines	**2,737**	3,608	3,906
U.S. Natural Gas Pipelines	**2,820**	2,785	2,516
Mexico Natural Gas Pipelines	**129**	173	357
Liquids Pipelines	**571**	1,442	954
Power and Storage	**842**	834	1,019
Corporate	**35**	58	32
	7,134	8,900	8,784

1 Capital spending includes Capital expenditures, Capital projects in development and Contributions to equity investments. Refer to Note 4, Segmented information, of our 2021 Consolidated financial statements for the financial statement line items that comprise total capital spending.

In 2021 and 2020, we invested $7.1 billion and $8.9 billion, respectively, in capital projects to maintain and optimize the value of our existing assets and to develop new, complementary assets in high-demand areas. Our total capital spending in 2021 and 2020 included contributions of $1.2 billion and $0.8 billion, respectively, to our equity investments, predominantly related to Bruce Power and Iroquois.

Proceeds from sales of assets

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

In 2020, we completed the following portfolio management transactions. All cash proceeds amounts are prior to income tax and post-closing adjustments:

- the sale of a 65 per cent equity interest in Coastal GasLink LP for proceeds of $656 million
- the sale of our Ontario natural gas-fired power plants for net proceeds of approximately $2.8 billion.

In addition to the proceeds from the above transactions, in 2020, we received $1.5 billion from the initial draw by Coastal GasLink LP on the project-level credit facility which preceded the equity sale.

Balance sheet

We continue to maintain a solid financial position while growing our total assets by $3.9 billion in 2021. At December 31, 2021, common shareholders' equity, including non-controlling interests, represented 35 per cent (2020 – 35 per cent) of our capital structure, while other subordinated capital, in the form of junior subordinated notes, redeemable non-controlling interest and preferred shares, represented an additional 15 per cent (2020 – 16 per cent). Refer to the Financial condition section for more information about our capital structure.

Dividends

We increased the quarterly dividend on our outstanding common shares by 3.4 per cent to $0.90 per common share for the quarter ending March 31, 2022 which equates to an annual dividend of $3.60 per common share. This was the 22nd 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 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. Commencing with the dividends declared October 31, 2019, common shares purchased under TC Energy's DRP are acquired on the open market at 100 per cent of the weighted average purchase price. From January 1, 2019 to October 31, 2019, common shares were issued from treasury at a discount of two per cent to market prices over a specified period.

Cash dividends paid

year ended December 31 (millions of $)	2021	2020	2019
Common shares	**3,317**	2,987	1,798
Preferred shares	**141**	159	160

OUTLOOK

Comparable EBITDA and comparable earnings

We expect our 2022 comparable EBITDA to be modestly higher than 2021; however, our 2022 comparable earnings per common share are expected to be consistent with 2021 largely due to the impact of a lower average foreign exchange hedge rate on our 2022 U.S. dollar-denominated earnings, as well as the following:

- growth in the NGTL System
- contributions from the Villa de Reyes pipeline expected to be placed in service
- higher AFUDC related to our Mexico natural gas pipeline projects subject to a successful resolution of the current contract dispute
- full-year impact from assets placed in service in 2021 and new projects anticipated to be placed in service in 2022, net of incremental depreciation expense
- lower contributions from the Keystone Pipeline System and reduced margins in the liquids marketing business
- higher Interest expense as a result of long-term debt issuances, net of maturities.

We continue to monitor developments in energy markets, our construction projects and regulatory proceedings as well as COVID-19 for any potential impacts on the above outlook.

Consolidated capital spending and equity investments

We expect to spend approximately $6.5 billion in 2022 on growth projects, maintenance capital expenditures and contributions to equity investments. The majority of the 2022 capital program is focused on NGTL System expansions, U.S. natural gas pipeline projects, the Bruce Power life extension program and normal course maintenance capital expenditures. We recognize that continued uncertainty exists on the duration of COVID-19 and the impact it could have on our construction activities and capital expenditures; however, we do not believe such disruptions will be material to our overall 2022 capital program.

Refer to the relevant business segment and Financial condition outlook sections for additional details on expected earnings and capital spending for 2022.

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 advance our goals to reduce our own carbon footprint as well as that of our customers.

Our capital program consists of approximately $24 billion of secured projects which 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 the year ended December 31, 2021, we placed approximately $2.3 billion of Canadian and U.S. natural gas pipelines capacity capital projects into service. In addition, approximately $1.8 billion of maintenance capital expenditures were incurred.

All projects are subject to cost and timing adjustments due to factors including weather, market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits, as well as other potential restrictions and uncertainties, including the ongoing impact of COVID-19. 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 our wholly-owned projects and our ownership share of equity contributions to fund projects within our equity investments, primarily Coastal GasLink and Bruce Power.

(billions of $)	Expected in-service date	Estimated project cost[1]	Project costs incurred as at December 31, 2021
Canadian Natural Gas Pipelines			
NGTL System[2]	2022	3.3	1.8
	2023	1.8	0.2
	2024+	0.5	—
Canadian Mainline	2022	0.2	0.1
Coastal GasLink[3]	2023	0.2	0.2
Regulated maintenance capital expenditures	2022-2024	2.1	—
U.S. Natural Gas Pipelines			
Modernization III (Columbia Gas)[4]	2022-2024	US 1.2	US 0.2
Delivery market projects	2025	US 1.5	—
Other capacity capital	2022-2025	US 1.5	US 0.9
Regulated maintenance capital expenditures	2022-2024	US 2.0	—
Mexico Natural Gas Pipelines			
Villa de Reyes	2022	US 1.0	US 0.9
Tula[5]	—	US 0.8	US 0.6
Liquids Pipelines			
Other capacity capital	2022-2023	US 0.2	US 0.1
Recoverable maintenance capital expenditures	2022-2024	0.1	—
Power and Storage			
Bruce Power – life extension[6]	2022-2027	4.4	1.9
Other			
Non-recoverable maintenance capital expenditures[7]	2022-2024	0.6	—
		21.4	6.9
Foreign exchange impact on secured projects[8]		2.2	0.7
Total secured projects (Cdn$)		23.6	7.6

1 Amounts reflect 100 per cent of costs related to wholly-owned assets as well as cash contributions to our joint-venture investments.
2 Estimated project costs for 2022 and 2023 include a total of $0.6 billion for Foothills related to the West Path Expansion Program.
3 The estimated project cost represents our share of anticipated partner equity contributions to the project, with the expected in-service date and estimated project cost reflecting the last project update. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information on the status of Coastal GasLink's dispute with LNG Canada regarding the recognition of certain costs and schedule changes. Refer to Note 11, Loans receivable from affiliates, of our 2021 Consolidated financial statements for information regarding our commitment to provide additional temporary financing, if necessary, to Coastal GasLink under certain circumstances.
4 Subject to FERC approval of the Columbia Gas uncontested rate case settlement. Refer to the U.S. Natural Gas Pipelines – Significant events section for additional information.
5 The East Section of the Tula pipeline is available for interruptible transportation services. We are working to procure necessary land access on the west section of the Tula pipeline to finalize its construction. The central segment construction has been delayed due to pending Indigenous consultation processes under the responsibility of the Secretary of Energy. Refer to the Mexico Pipelines – Significant events section for additional information.
6 Reflects our expected share of cash contributions for the Bruce Power Unit 6 Major Component Replacement (MCR) program, expected to be in service in 2023, amounts to be invested under the Asset Management program through 2027 as well as the incremental uprate initiative. In addition, it includes our expected share of cash contributions for the Unit 3 MCR, subject to IESO approval of the basis of estimate. Refer to the Power and Storage – Significant events section for additional information.
7 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 Power and Storage assets.
8 Reflects U.S./Canada foreign exchange rate of 1.27 at December 31, 2021.

Projects under development

In addition to our secured projects, we have a portfolio of projects that we are currently pursuing which are in varying stages of development. 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. Each business segment has also outlined additional areas of focus for further ongoing business development activities and growth opportunities. As these projects are advanced, reaching 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 and connections to growing shale gas supplies. Sustainability development projects will include additional compressor station electrification and waste heat capture power generation on our systems as well as other GHG abatement initiatives.

U.S. Natural Gas Pipelines

Delivery Market Projects

Projects are in development that will replace, upgrade and modernize certain U.S. Natural Gas Pipelines facilities while reducing emissions along portions of our pipeline systems' principal delivery markets. The enhanced facilities are expected to improve reliability of our systems and allow for additional contracted transportation services to address growing demand in the U.S. Midwest and the Mid-Atlantic regions under long-term contracts while reducing direct carbon dioxide equivalent (CO_2e) emissions. Included in our secured projects are the US$0.7 billion VR Project on Columbia Gas and the US$0.8 billion WR Project on ANR, two delivery market projects that were approved in 2021 with expected in-service dates in the second half of 2025.

Other Opportunities

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

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

Mexico Natural Gas Pipelines

We are currently evaluating new growth projects driven by Mexico's economic expansion and the need to connect natural gas to new regions of the country to serve power plants, industrial demand and LNG exports and, in doing so, reduce reliance on costly, carbon intensive fuel oil. Potential projects include a re-route of the central segment of Tula as well as a new offshore pipeline that would connect additional natural gas supply to Southeast Mexico and capacity expansions on existing assets.

Liquids Pipelines

Grand Rapids Phase II

Regulatory approvals have been obtained for Phase II of Grand Rapids which consists of completing the 36-inch pipeline for crude oil service and converting the 20-inch pipeline from crude oil to diluent service. Commercial support is being pursued with prospective customers.

Terminals Projects

We continue to pursue projects associated with our terminals in Alberta and the U.S. to expand our core business and add operational flexibility for our customers.

Other Opportunities

We remain focused on maximizing the value of our liquids assets by expanding and leveraging our existing infrastructure and enhancing connectivity and service offerings to our customers. We are pursuing selective growth opportunities to add incremental value to our Liquids Pipelines business and expansions that leverage available 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 Storage

Bruce Power

Life Extension Program

The continuation of Bruce Power's life extension program through to 2033 will require the investment of our proportionate share of Major Component Replacement (MCR) program costs on Units 3, 4, 5, 7 and 8, as well as the remaining Asset Management program costs which continue beyond 2033. This program will extend the life of Units 3 to 8 and the Bruce Power site to 2064. The basis of estimate for the Unit 3 MCR was submitted to the IESO in December 2021 for a refurbishment outage expected to begin in first quarter 2023. Preparation work for the Unit 4 MCR is well underway and work for Unit 5, 7 and 8 MCRs have also begun. 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 $4.8 billion for our proportionate share of the Bruce Power MCR program costs for Units 4, 5, 7 and 8, the remaining Asset Management program costs beyond 2027, as well as the incremental uprate initiative discussed below.

Uprate Initiative

Bruce Power recently 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. 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, beginning in early 2022, is targeting another 200 MW. Both stages are expected to increase output in multiple steps ending in 2033. Stage 3 requires Stage 1 and 2 to be complete and would enable an increase to the reactor power limit.

Development-Stage Projects

Ontario Pumped Storage

We continue to progress the development of the Ontario Pumped Storage project, an energy storage facility located near Meaford, Ontario that would provide 1,000 MW of flexible, clean energy to Ontario's electricity system using a process known as pumped hydro storage.

Two key milestones on the Ontario Pumped Storage project were reached in 2021. On July 28, 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. On November 11, 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 will 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.

Saddlebrook Solar and Storage

We are proposing to construct and operate the Saddlebrook Solar and Storage project, a solar and energy storage solution, which consists of a solar-generating facility located in Aldersyde, Alberta that will operate in conjunction with a battery energy storage system.

The proposed generating facility will produce approximately 81 MW of power and the battery storage system will provide up to 40 MWh of energy storage capacity and is expected to reduce GHG emissions by approximately 115,000 tonnes per year. The proposed project is partially funded through Emissions Reduction Alberta's Biotechnology, Electricity and Sustainable Transportation Challenge. We expect to make a final investment decision on the project in 2022 with the first phases of commissioning beginning towards the end of 2022.

Canyon Creek Pumped Storage

We acquired 100 per cent ownership of the Canyon Creek pumped storage development project in 2021. Once in service, the facility will have initial generating capacity of 75 MW, expandable through future development to 400 MW, and will utilize existing site infrastructure from a decommissioned coal mine. The facility will 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 Alberta Government for hydro projects under the Hydro Development Act.

The Canyon Creek Pumped Storage project is part of a larger product offering by us, a 24-by-7 carbon-free power product in the Province of Alberta and includes output from other projects currently under construction or being developed, thereby positioning our customers to manage hourly power needs with cost certainty and achieve decarbonization goals by sourcing power from emissions-free assets.

Renewable Energy Request for Information (RFI)

In 2021, we announced that we were seeking to identify potential contracts and/or investment opportunities in wind, solar and power storage renewable energy projects. We requested up to 620 MW of wind energy projects, 300 MW of solar projects and 100 MW of energy storage projects to meet the electricity needs of the U.S. portion of the Keystone Pipeline System assets. 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. We received a significant number of responses to our RFI and are currently evaluating proposals and expect to finalize contracts during the first half of 2022.

Other Opportunities

We are actively building our customer-focused origination platform across North America, providing commodity products and energy services to help customers address the challenges of energy transition. Our existing network of assets, customers and suppliers provide a mutual opportunity in which we can tailor solutions to meet their clean energy needs. Although we may adopt a custom-tailored strategy for each of our partnerships, the core underpinning remains consistent, which is that every opportunity we undertake will ultimately be driven by customer needs allowing us to complement each other’s capabilities, diversify risk and share learnings as we navigate the energy transition.

Refer to the Power and Storage – Significant events section for additional information.

Other Energy Transition Developments

Our vision is to be the premier energy infrastructure company in North America today and in the future. That future includes embracing the energy transition that is underway and contributing to a lower-carbon energy world. As energy transition continues to evolve, we recognize a significant opportunity to reduce our emissions footprint, in addition to being a partner to our customers and other industries which are also looking for low-carbon solutions. Currently, it is uncertain how the energy mix will evolve and at what pace. We continue to observe a reliance on the existing sources of natural gas, crude oil and electricity, for which we currently provide services to our customers.

We are targeting five focus areas to reduce the emissions intensity of our operations, while also capturing growth opportunities that meet the energy needs of the future:

- modernize our existing system and assets
- decarbonize our energy consumption
- drive digital solutions and technologies
- leverage carbon credits and offsets
- invest in low-carbon energy and infrastructure, such as renewables along with emerging fuels and technology.

Alberta Carbon Grid (ACG)

On June 17, 2021, we announced a partnership with Pembina Pipeline Corporation to jointly develop a world-scale carbon transportation and sequestration system which, when fully constructed, will be capable of transporting more than 20 million tonnes of carbon dioxide annually, thereby providing opportunities to retrofit existing assets and reduce our carbon footprint. By leveraging existing pipelines and a newly developed sequestration hub, the ACG is expected to provide an infrastructure platform for Alberta-based industries to manage their emissions and contribute to a lower-carbon economy. Designed to be an open-access system, the ACG would connect the Fort McMurray, Alberta Industrial Heartland and Drayton Valley regions to key sequestration locations and delivery points across the province. We are also pursuing opportunities to leverage our existing systems in support of hydrogen production and transportation.

Irving Oil Decarbonization

On August 12, 2021, we signed an MOU to explore the joint development of a series of proposed energy projects focused on reducing GHG emissions and creating new economic opportunities in New Brunswick and Atlantic Canada. Together with Irving Oil, we have identified a series of potential projects focused on decarbonizing existing assets and deploying emerging technologies to reduce overall emissions over the medium and long term. The partnership's initial focus will consider a suite of upgrade projects at Irving Oil's refinery in Saint John, New Brunswick, with the goal of significantly reducing emissions through the production and use of low-carbon power generation.

Hydrogen Hubs

We have entered into two Joint Development Agreements (JDA), to support customer-driven hydrogen production for long-haul transportation, power generation, large industrials and heating customers across the United States and Canada. The first opportunity is a partnership with Nikola Corporation, a designer and manufacturer of zero-emission battery-electric and hydrogen-electric vehicles and related equipment, where Nikola will be a long-term anchor customer for hydrogen production infrastructure supporting hydrogen fueled zero-emission heavy-duty trucks. The JDA with Nikola supports co-development of large-scale green and blue hydrogen production hubs, utilizing our power and natural gas infrastructure.

Our second customer-driven opportunity is a partnership with Hyzon Motors, a leader in fuel cell electric mobility for commercial vehicles, to develop hydrogen production facilities focused on zero-to-negative carbon intensity hydrogen from renewable natural gas, biogas and other sustainable sources. The facilities will be located close to demand, supporting Hyzon's back-to-base vehicle deployments. 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.

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 – 88,110 km (54,748 miles)
- partially-owned natural gas pipelines – 5,184 km (3,221 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 535 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

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 and developing new projects to provide connectivity to LNG export terminals, both operating and proposed, in Canada, the U.S. and Mexico
- connections to growing Canadian and U.S. shale gas and other supplies
- decarbonizing our energy consumption, thereby reducing overall GHG 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 intensity reduction targets, 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 renewable natural gas customers are connecting to our system. Our business 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 $1.2 billion of projects placed into service in 2021
- received federal approval for the 2022 NGTL System Expansion Program with in-service dates anticipated in 2022
- CER approved the 2023 NGTL System Intra-Basin Expansion Program
- advanced construction of the Coastal GasLink pipeline project.

U.S. Natural Gas Pipelines

- placed approximately US$2.4 billion of capital projects into service including BXP on Columbia Gas and Grand Chenier XPress on ANR
- originated an additional US$2.9 billion of growth projects including the GHG emissions-reducing Delivery Market projects on Columbia Gas and ANR, as well as the Columbia Gas Modernization III program
- Columbia Gas uncontested rate settlement filed with FERC and GTN rate settlement approved by FERC
- ANR filed a Section 4 rate case with FERC on January 28, 2022 requesting an increase to maximum transportation rates effective August 1, 2022, subject to refund. As the rate process progresses, we expect to engage in a collaborative process to achieve settlement with our customers, FERC and other stakeholders
- achieved record throughput volumes on certain pipelines.

Mexico Natural Gas Pipelines

- advanced resolution of the arbitration with the CFE on the Tula and Villa de Reyes pipeline projects with the signing of an MOU on July 30, 2021
- commenced feasibility assessments with the CFE under the MOU to jointly evaluate potential alternatives to complete the Tula pipeline and a new offshore pipeline to connect natural gas to southeast Mexico
- continued construction of the Villa de Reyes pipeline project with phased commissioning and in-service expected in 2022 subject to timely receipt of pending authorizations and land access to critical pipeline sections
- assets performed with 100 per cent reliability and asset 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 38 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 System: This is our natural gas gathering and transportation system for the WCSB, connecting most of the natural gas production in western Canada to domestic and export markets. 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 of the system or future connections to other pipelines serving that area.

Canadian Mainline: This pipeline supplies markets in Ontario, Québec, the Canadian Maritimes as well as the Midwest and Northeast U.S. 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.

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.

Other U.S. Natural Gas Pipelines: We have ownership interests in eight wholly-owned or partially-owned natural gas pipelines serving major markets in the U.S. that were previously held by our subsidiary, TC PipeLines, LP. On March 3, 2021, we completed the acquisition of all of the outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy, in exchange for TC Energy common shares, resulting in TC PipeLines, LP becoming an indirect, wholly-owned subsidiary of TC Energy, thereby increasing our effective ownership in the TC PipeLines, LP assets. Refer to the Corporate – Significant events section for additional information.

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 2021 supplied approximately 15 per cent of Mexico's total natural gas imports via pipelines. We own a 60 per cent interest in 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 and the Tula and Villa de Reyes pipelines currently under construction. This system supplies, or will supply, several power plants and industrial facilities in Veracruz, San Luis Potosí, Querétaro and Hidalgo. It has interconnects with upstream pipelines that bring in supply from the Agua Dulce and Waha basins 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 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 121 Bcf/d by 2026, reflecting an increase of approximately 18 Bcf/d from 2021 levels.

As the world shifts toward lower-emission fuel sources, 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. This expected growth in demand for natural gas, coupled with the anticipated production increases in key producing areas like WCSB, onshore Gulf Coast, Appalachia and the Permian basin, will provide investment opportunities for pipeline infrastructure companies to build new facilities or increase utilization of the existing footprint. Modernizing and decarbonizing our natural gas pipeline systems will provide ongoing additional capital investment opportunities that will meet our risk preferences while supporting our GHG intensity reduction goals.

Changing demand

The abundant supply of natural gas has supported increased demand, particularly in the following areas:

- natural gas-fired power generation
- 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, the west coast of Canada, the U.S. and Mexico and the east coast of Canada. The increasing supply of natural gas in Mexico is driven by the CFE's need to serve existing markets by connecting natural gas plants to supply and building pipelines to serve new regions. They are forecasting significant gas demand growth in the future to support economic expansion and conversion to lower carbon fuels for industrial and power generation use. 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. The growing focus on ESG is expected to result in shifting market dynamics, as both energy demand and pressure for accelerated climate action increase simultaneously.

Commodity prices

In general, 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

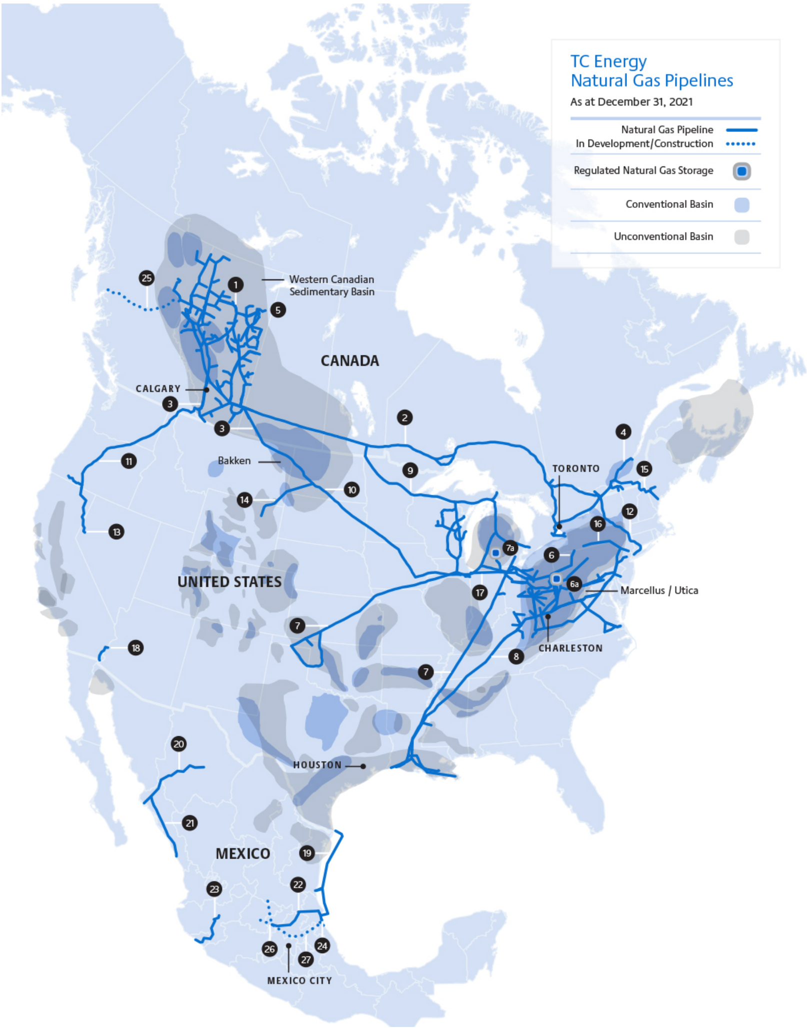
Changes in supply and demand levels and locations have resulted in increased competition to provide transportation services throughout North America. Our well-distributed footprint of natural gas pipelines, particularly in the liquids-rich and low-cost WCSB and the Appalachian basin, both of which are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

In 2022, some of our key focus areas will be the continued execution of our existing capital program that includes further investment in the NGTL System, continued construction of Coastal GasLink as well as the completion and initiation of new pipeline projects in the U.S. and Mexico. We will also 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, of the environment and general public impacted by the construction and operation of these facilities.

Our natural gas marketing entities will complement our 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, 2021
Natural Gas Pipeline
In Development/Construction
Regulated Natural Gas Storage
Conventional Basin
Unconventional Basin
Western Canadian Sedimentary Basin
CANADA
CALGARY
Bakken
TORONTO
UNITED STATES
Marcellus / Utica
CHARLESTON
HOUSTON
MEXICO
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	24,494 km (15,220 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 eastern Canada and interconnects to the U.S.	100 %
3	Foothills	1,237 km (769 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)	574 km (357 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 %
	Great Lakes Canada[1]	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			
6	Columbia Gas	18,815 km (11,691 miles)	Transports natural gas primarily from the Appalachian basin to markets and pipeline interconnects throughout the U.S. Northeast, Midwest and Atlantic regions.	100 %
6a	Columbia Storage	285 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key eastern markets. We also own a 50 per cent interest in the 12 Bcf Hardy Storage facility.	100 %
7	ANR	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 %
7a	ANR Storage	250 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key mid-western markets.	
8	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.	100 %
9	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 %
10	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 %
11	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 %
12	Iroquois	669 km (416 miles)	Connects with the Canadian Mainline and serves markets in New York.	50 %
13	Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to markets in northeastern California and northwestern Nevada.	100 %
14	Bison	488 km (303 miles)	Transports natural gas from the Powder River basin in Wyoming to Northern Border in North Dakota.	100 %
15	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
16	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 %
17	Crossroads	325 km (202 miles)	Interstate natural gas pipeline operating in Indiana and Ohio with multiple interconnects to other pipelines.	100 %
18	North Baja	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			
19	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 %
20	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 %
21	Mazatlán	430 km (267 miles)	Transports natural gas from El Oro to Mazatlán, Sinaloa and connects to the Topolobampo Pipeline at El Oro.	100 %
22	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 %
23	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 %
24	Tula – East Section	48 km (30 miles)	The East Section of the Tula pipeline is available to transport natural gas from Sur de Texas to power plants in Tuxpan, Veracruz.	100 %
	Under construction			
	Canadian pipelines			
25	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 under construction near Kitimat, British Columbia	35 %
	NGTL System 2022 Facilities[1,2]	415 km (258 miles)	Multiple components of the 2021 NGTL System Expansion Program, 2022 NGTL System Expansion Program and 2023 NGTL System/Foothills West Path Delivery Program, along with other facilities, with expected in-service dates in 2022.	100 %

	Under construction (continued)	Length	Description	Ownership
	U.S. pipelines			
	Elwood Power/ANR Horsepower Replacement[3]	n/a	A reliability project on ANR that will replace and upgrade certain facilities with expected in-service in 2022.	100 %
	Wisconsin Access[3]	n/a	A reliability project on ANR that will replace and upgrade certain facilities with expected in-service in 2022.	100 %
	Alberta XPress[3]	n/a	An expansion project of ANR through compressor station modifications and additions with expected in-service commencing in 2022.	100 %
	Mexico pipelines			
26	Villa de Reyes	420 km (261 miles)	This bidirectional pipeline will transport natural gas to Tula, Hidalgo and Villa de Reyes, San Luis Potosí, connecting to the Tamazunchale and Tula pipelines as well as other pipeline systems, and the Salamanca industrial complex in the state of Guanajuato.	100%
27	Tula (excluding the East Section)	276 km (171 miles)	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.	100 %
	Permitting and pre-construction phase			
	NGTL System 2023/2024 Facilities[1,2]	199 km (124 miles)	Multiple components of the 2022 NGTL System Expansion Program, 2023 NGTL System/Foothills West Path Delivery Program and 2023 NGTL System Intra-Basin Expansion, along with other facilities, with expected in-service dates commencing in 2023.	100 %
	U.S. pipelines			
	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 with expected in-service in 2025.	100 %
	WR Project[3]	n/a	A delivery market project on ANR that will replace and upgrade certain facilities while improving reliability and reducing emissions with expected in-service in 2025.	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 Project includes compressor station modifications and additions with no additional pipe length.

Canadian Natural Gas Pipelines

UNDERSTANDING OUR CANADIAN NATURAL GAS PIPELINES SEGMENT

The Canadian natural gas pipeline 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 Coastal GasLink, which is currently under construction.

For the interprovincial natural gas pipelines it regulates, the CER approves tolls and services that are in the public interest and provide a reasonable opportunity for a 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 throughput 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.

We and our shippers can also establish settlement arrangements, subject to approval by the CER, 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. Beginning January 1, 2021, 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 Pipeline Project

Coastal GasLink is a pipeline under construction that will have an initial capacity of approximately 2.2 PJ/d (2.1 Bcf/d) and will deliver natural gas from the Dawson Creek area to a natural gas liquefaction facility near Kitimat, British Columbia. The LNG facility, which is owned by LNG Canada, is currently under construction. Transportation service on the pipeline is underpinned by 25-year TSAs (with additional renewal provisions) with each of the five LNG Canada participants. We currently hold a 35 per cent ownership interest in Coastal GasLink LP and have been contracted to develop and operate the pipeline.

The project is currently more than 59 per cent complete. The entire route has been cleared, grading is more than 70 per cent complete and more than 240 km (149 miles) of pipeline has been installed, with reclamation activities underway in many areas.

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 from late December 2020 until mid-April 2021, we continue to expect project costs to increase significantly along with a delay to project completion compared to the original project cost and schedule. Coastal GasLink has sought to mitigate cost increases and schedule delays and will continue to do so.

Coastal GasLink is in dispute with LNG Canada with respect to the recognition of certain costs and the impacts on schedule; however, the parties are in active and constructive discussions toward a resolution of this matter. We do not expect any suspension of construction activities while discussions continue. The ultimate level of debt financing and the amounts to be contributed as equity by Coastal GasLink LP partners, including us, will be determined by the substance of a resolution with LNG Canada.

During this time, in addition to using funds from its $6.8 billion project-level credit facility and the recovery of construction carrying costs from LNG Canada, construction is also being funded in part by a subordinated demand revolving facility with TC Energy which has a current capacity of $500 million and provides the project with additional short-term funding and financial flexibility. At December 31, 2021, $1 million was outstanding on this revolving facility.

In fourth quarter 2021, as a further 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. This financing will be provided through a combination of interest-bearing loans and loans that are subject to a return to TC Energy under certain conditions at the time the final cost of the project is determined. At December 31, 2021, $238 million was outstanding on these loans.

NGTL System

In the year ended December 31, 2021, the NGTL System placed approximately $1.1 billion of capacity projects in service.

2022 NGTL System Expansion Program

In 2021, we received regulatory approval for the 2022 NGTL System Expansion Program. With an estimated capital cost of $1.2 billion, the 2022 NGTL System Expansion Program consists of approximately 166 km (103 miles) of new pipeline, one new compressor unit and associated facilities and will provide incremental capacity of approximately 773 TJ/d (722 MMcf/d) to meet firm-receipt and intra-basin delivery requirements with eight-year terms. Construction activities began in September 2021 with anticipated in-service dates commencing in fourth quarter 2022.

2023 NGTL System Intra-Basin Expansion

In 2021, we received regulatory approval to construct and operate the NGTL System Intra-Basin Expansion Program, consisting 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. Based on the outcome of the 2021 Capacity Optimization Open Season, changes in expected supply have reduced the scope of the program which now has an estimated capital cost of $0.6 billion. The NGTL System Intra-Basin Expansion is expected to be placed in service commencing in 2023.

NGTL System/Foothills West Path Delivery Program

In 2019, we announced our West Path Delivery Program which is an expansion of the NGTL System and Foothills for contracted incremental export capacity on GTN. The Canadian portion of the expansion program has an estimated capital cost of $1.2 billion as a result of refined cost estimates and increased construction costs and consists of approximately 107 km (66 miles) of pipeline and associated facilities with in-service dates in fourth quarter 2022 and fourth quarter 2023. The program is underpinned by approximately 275 TJ/d (258 MMcf/d) of new firm-service contracts with terms that exceed 30 years. Regulatory approvals to construct and operate $0.4 billion of the facilities have been received and applications for the remaining facilities have been submitted with approvals anticipated in first and fourth quarter 2022.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (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 $)	**2021**	**2020**	**2019**
NGTL System	**1,649**	1,509	1,210
Canadian Mainline	**838**	911	952
Other Canadian pipelines[1]	**188**	146	112
Comparable EBITDA	**2,675**	2,566	2,274
Depreciation and amortization	**(1,226)**	(1,273)	(1,159)
Comparable EBIT	**1,449**	1,293	1,115
Specific item:			
Gain on partial sale of Coastal GasLink LP	**—**	364	—
Segmented earnings	**1,449**	1,657	1,115

1 Includes results from Foothills, Ventures LP, Great Lakes Canada and our investment in TQM, Coastal GasLink development fee revenue as well as general and administrative and business development costs related to our Canadian Natural Gas Pipelines.

Canadian Natural Gas Pipelines segmented earnings decreased by $208 million in 2021 compared to 2020 and increased by $542 million in 2020 compared to 2019. Segmented earnings in 2020 include a pre-tax gain of $364 million related to the sale of a 65 per cent equity interest in Coastal GasLink LP which has been excluded from our calculation of comparable EBITDA and comparable EBIT.

Net income and comparable EBITDA for our rate-regulated Canadian natural gas pipelines are primarily affected by our approved ROE, our 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 $)	2021	2020	2019
Net income			
NGTL System	**631**	565	484
Canadian Mainline	**213**	160	173
Average investment base			
NGTL System	**15,560**	14,070	11,959
Canadian Mainline	**3,724**	3,673	3,690

Net income for the NGTL System increased by $66 million in 2021 compared to 2020 and $81 million in 2020 compared to 2019 mainly due to a higher average investment base resulting from continued system expansions. Effective January 1, 2020, the NGTL System is operating under the 2020-2024 Revenue Requirement Settlement which includes an 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. The NGTL System's 2019 results reflected the 2018-2019 Revenue Requirement Settlement that expired on December 31, 2019 and included an ROE of 10.1 per cent on 40 per cent deemed common equity, a mechanism for sharing variances above and below a fixed annual OM&A amount and flow-through treatment of all other costs.

Net income for the Canadian Mainline increased by $53 million in 2021 compared to 2020 mainly as a result of higher incentive earnings and the elimination of a $20 million after-tax annual TC Energy contribution included in the previous settlement. Net income in 2020 decreased by $13 million compared to 2019 mainly as a result of lower incentive earnings. Effective January 1, 2021, 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. In 2020 and 2019, the Canadian Mainline operated under the terms of the 2015-2030 Tolls Application approved in 2014. The terms of the previous settlement included an ROE of 10.1 per cent on deemed common equity of 40 per cent, an incentive mechanism with both upside and downside risk and a $20 million after-tax annual TC Energy contribution to reduce the revenue requirement.

Comparable EBITDA

Comparable EBITDA for Canadian Natural Gas Pipelines was $109 million higher in 2021 compared to 2020 primarily due to the net effect of:

- higher flow-through depreciation and income taxes as well as increased rate-base earnings on the NGTL System
- Coastal GasLink development fee revenue which commenced in second quarter 2020
- lower flow-through depreciation and financial charges, partially offset by higher flow-through income taxes, increased incentive earnings and elimination of the TC Energy contribution on the Canadian Mainline.

Comparable EBITDA for Canadian Natural Gas Pipelines in 2020 was $292 million higher than 2019 primarily due to the net effect of:

- increased rate-base earnings and flow-through depreciation due to additional facilities placed in service as well as higher flow-through financial charges on the NGTL System
- lower flow-through income taxes and reduced incentive earnings on the Canadian Mainline and the NGTL System
- Coastal GasLink development fee revenue which commenced in 2020.

Depreciation and amortization

Depreciation and amortization was $47 million lower in 2021 compared to 2020 mainly 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 in 2021 and 2020. Depreciation and amortization was $114 million higher in 2020 compared to 2019 due to additional NGTL System facilities placed in service in 2020 and 2019.

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 is expected to be higher in 2022 driven by continued NGTL System expansion and recovery of flow-through items, partially offset by the reduction of flow-through depreciation in the Canadian Mainline as one segment was fully depreciated in 2021. Due to the flow-through treatment of certain expenses on our Canadian regulated pipelines, changes in these amounts can impact our comparable EBITDA despite having no significant effect on comparable earnings.

Canadian Natural Gas Pipelines comparable earnings in 2022 are expected to be higher than 2021 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.

Capital spending

We spent a total of $2.7 billion in 2021 in our Canadian natural gas pipelines business on growth projects and maintenance capital expenditures. We expect to spend approximately $3.5 billion in 2022, primarily on NGTL System expansion projects and maintenance capital expenditures, all of which are immediately reflected in investment base and related earnings.

U.S. Natural Gas Pipelines

UNDERSTANDING OUR U.S. NATURAL GAS PIPELINES SEGMENT

The U.S. interstate natural gas pipeline business is subject to regulation by various federal, state and local governmental agencies. FERC, however, has comprehensive jurisdiction over our U.S. 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 disseminated regulations governing, among other things, maximum operating pressures, pipeline patrols and leak surveys, public awareness, operation and maintenance procedures, operator qualification, minimum depth requirements and emergency procedures. Additionally, PHMSA has put into place regulations requiring pipeline operators to develop and implement integrity management programs for certain natural gas pipelines that, in the event of a pipeline leak or rupture, could affect high-consequence areas, which are areas where a release could have the most significant adverse consequences, including high-population areas.

During 2016, PHMSA proposed new rules to revise the U.S. Federal Pipeline Safety Regulations and issued a Notice of Public Rulemaking (NPRM) for natural gas transmission and gathering lines that would, if adopted, impose more stringent inspection, reporting and integrity management requirements on operators. However, PHMSA has since decided to split its 2016 proposed rule, which has become known as the Gas Mega Rule, into three separate rulemakings focusing on (1) maximum allowable operating pressure and integrity assessments on non-high consequence areas known as moderate consequence areas; (2) repair criteria, inspections and corrosion control; and (3) gathering lines. The first of these three rulemakings, for onshore natural gas transmission pipelines, was published as a final rule in October 2019 and the gathering line rule (part three) was issued in November 2021. We continue to assess the operational and financial impact related to this final rule over its 15-year implementation window that began in July 2020 and seek to optimize recovery of those costs. The remaining rulemaking comprising the Gas Mega Rule is currently expected to be issued in April 2022.

In addition to the rulemakings noted above, new pipeline safety legislation was signed into law in December 2020 that reauthorized PHMSA pipeline safety programs that expired under the 2016 Pipeline Safety Act at the end of September 2019. We are in the process of assessing the impacts associated with this new legislation which include self-directed mandates to natural gas transmission operations requiring targeted reduction of methane releases.

The Pipeline Rupture Detection and Mitigation for Onshore Populated and High Consequence Areas (HCAs) rulemaking is expected to be published as a final rule in March 2022. The rupture detection and mitigation rule will define when the installation of automatic shutoff valves, remote-controlled valves or manual valves is required on newly constructed pipelines or replacements six inches and larger in diameter. The rule primarily targets Class 3 and 4 locations and HCAs but also includes more stringent mandates on the timeliness of response and the ability for the Supervisory Control and Data Acquisition System to detect and alert operations controllers of potential large-scale leaks with a 40-minute requirement to have a release fully isolated. We have provided initial comments on the NPRM and will perform a full assessment when the rule is issued as final.

TC PipeLines, LP

On March 3, 2021, we completed the acquisition of all of the outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy. TC PipeLines, LP has ownership interests in the GTN, Northern Border, Bison, Great Lakes, North Baja, Tuscarora, Iroquois and Portland pipeline systems. Our overall ownership for each of these assets is provided in the asset listing of our major pipelines starting on page 39. Refer to the Corporate – Significant events section for additional information regarding the acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy.

SIGNIFICANT EVENTS

Columbia Gas Section 4 Rate Case

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, subject to refund upon completion of the rate proceeding. On July 28, 2021, Columbia Gas notified FERC that it reached a settlement-in-principle with its customers addressing all remaining issues in the case, including but not limited to the resolution of rates and continuation of Columbia Gas's modernization program. On October 29, 2021, Columbia Gas filed its settlement with FERC, and is now awaiting approval, with 2021 revenues expected to be generally consistent with estimates recorded to date. On December 17, 2021, the presiding Administrative Law Judge recommended the settlement for approval and certified it as uncontested to FERC for its review and approval. While there is no timeframe in which FERC must act on the settlement, in line with other recent rate case settlement approval timelines, we expect to receive approval of the settlement in early 2022.

Grand Chenier XPress

Phase I of Grand Chenier XPress, an expansion project on ANR connecting supply directly to U.S. Gulf Coast LNG export facilities, went into service in April 2021. Phase II was placed in service in January 2022.

Delivery Market Projects

We are actively developing projects that will replace and upgrade certain facilities while reducing emissions along portions of our pipeline systems in principal delivery markets. The enhanced facilities are expected to improve reliability of the systems and allow for additional transportation services to address growing demand under long-term contracts while reducing direct CO_2e emissions. Consistent with this initiative, the VR project on Columbia Gas was sanctioned in 2021, subject to customary conditions precedent and normal-course regulatory approvals. This project represents an approximate US$0.7 billion capital investment and is targeted to be placed in service during the second half of 2025. Similarly, the WR project on ANR was also sanctioned in 2021 and will serve markets in the midwestern U.S. This project has an estimated capital cost of approximately US$0.8 billion and is expected to be placed in service in fourth quarter 2025.

GTN Rate Case Settlement

On September 29, 2021, GTN filed an uncontested rate settlement which would set new recourse rates for GTN effective January 1, 2022 and institute a rate moratorium through December 31, 2023. The uncontested rate settlement was approved by FERC on November 18, 2021. The revised rates are not expected to have a significant impact on our U.S. Natural Gas Pipelines segment comparable earnings. In addition, GTN must file for new rates no later than April 1, 2024.

GTN XPress

The GTN XPress expansion project filed its FERC certificate application in fourth quarter 2021 and is expected to be placed in service in the second half of 2023.

Modernization III

Subject to FERC approval as part of the Columbia Gas uncontested rate settlement, Columbia Gas and its customers entered into a settlement arrangement (Modernization III) which provides recovery and return on investment to modernize its system, 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 to be completed through 2024. As per the terms of the arrangement, facilities in service by November 30 of each year collect revenues effective April 1 of the following year until the arrangement is terminated. New rates will become effective once Columbia Gas files a subsequent Section 4 rate case under the Natural Gas Act.

ANR Section 4 Rate Case

ANR filed a Section 4 rate case with FERC on January 28, 2022 requesting an increase to ANR's maximum transportation rates effective August 1, 2022, subject to refund upon completion of the rate proceeding. As the rate case process progresses, we expect to engage in a collaborative process to achieve settlement with our customers, FERC and other stakeholders.

FINANCIAL RESULTS

On March 3, 2021, we acquired all the outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy in exchange for TC Energy common shares (TC PipeLines, LP acquisition). TC PipeLines, LP results for the year ended December 31, 2021 and comparative results for 2020 and 2019 reflect our ownership interests in eight natural gas pipelines prior to the acquisition.

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (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$, unless otherwise noted)	**2021**	**2020**	**2019**
Columbia Gas	**1,529**	1,305	1,222
ANR	**592**	512	492
Columbia Gulf	**220**	195	164
Great Lakes[1,2]	**158**	91	86
GTN[2,3]	**139**	—	—
Other U.S. pipelines[2,5]	**313**	117	172
TC PipeLines, LP[2,4]	**24**	119	119
Non-controlling interests[4]	**100**	375	368
Comparable EBITDA	**3,075**	2,714	2,623
Depreciation and amortization	**(630)**	(597)	(568)
Comparable EBIT	**2,445**	2,117	2,055
Foreign exchange impact	**620**	720	671
Comparable EBIT (Cdn$)	**3,065**	2,837	2,726
Specific items:			
Gain on sale of Columbia Midstream assets	**—**	—	21
Risk management activities	**6**	—	—
Segmented earnings (Cdn$)	**3,071**	2,837	2,747

1 Results reflect our 53.55 per cent direct interest in Great Lakes until March 3, 2021 and our 100 per cent ownership interest subsequent to the TC PipeLines, LP acquisition.

2 Our ownership interest in TC PipeLines, LP was 25.5 per cent prior to our acquisition on March 3, 2021, at which time it became 100 per cent. Prior to March 3, 2021, TC PipeLines, LP's results reflected a 46.45 per cent ownership interest in Great Lakes, its ownership of GTN, Bison, North Baja, Portland and Tuscarora as well as its share of equity income from Northern Border and Iroquois.

3 Reflects 100 per cent of GTN's comparable EBITDA, subsequent to our acquisition of TC PipeLines, LP on March 3, 2021.

4 Reflects comparable EBITDA attributable to portions of TC PipeLines, LP and Portland that we did not own prior to our acquisition of TC PipeLines, LP on March 3, 2021, and subsequently reflects earnings attributable to the remaining 38.3 per cent interest in Portland we do not own.

5 Reflects comparable EBITDA from our ownership in our mineral rights business, Crossroads and our share of equity income from Millennium and Hardy Storage, as well as general and administrative and business development costs related to our U.S. natural gas pipelines. For the period subsequent to our acquisition of TC PipeLines, LP on March 3, 2021, results also include 100 per cent of Bison, North Baja and Tuscarora, 61.7 per cent of Portland, plus our equity income from Northern Border and Iroquois.

U.S. Natural Gas Pipelines segmented earnings in 2021 increased by $234 million compared to 2020 and increased by $90 million in 2020 compared to 2019 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- unrealized gains from changes in the fair value of derivatives related to our U.S. natural gas marketing business in 2021
- a pre-tax gain of $21 million related to the sale of certain Columbia Midstream assets in August 2019.

A weaker U.S. dollar in 2021 had a negative impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2020, while a stronger U.S. dollar in 2020 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2019.

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 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$361 million higher in 2021 than 2020 primarily due to the net effect of:

- a net increase in earnings from Columbia Gas as a result of the higher transportation rates effective February 1, 2021, pursuant to the Columbia Gas uncontested rate case settlement. Refer to the U.S. Natural Gas Pipelines – Significant events section for additional information
- increased earnings across our U.S. Natural Gas Pipelines assets which includes the impact of cold weather events in 2021 impacting many of the U.S. markets in which we operate
- increased earnings from our mineral rights business due to higher commodity prices
- incremental earnings resulting from increased capitalization of pipeline integrity costs and the contribution from growth projects placed in service primarily on Columbia Gas and ANR, partially offset by higher property taxes.

Comparable EBITDA for U.S. Natural Gas Pipelines was US$91 million higher in 2020 than 2019 primarily due to the net effect of:

- incremental earnings from Columbia Gas and Columbia Gulf growth projects placed in service as well as lower operating costs in 2020
- increased earnings from ANR due to the sale of natural gas from certain gas storage facilities
- decreased earnings as a result of the sale of certain Columbia Midstream assets in August 2019.

The positive impact on comparable earnings following the TC PipeLines, LP acquisition noted above is reflected through a reduction in Non-controlling interests. Refer to the Corporate – Financial results section for additional information.

Depreciation and amortization

Depreciation and amortization was US$33 million higher in 2021 compared to 2020 mainly due to new projects placed in service, net of certain fourth quarter 2021 adjustments related to the Columbia Gas uncontested rate case settlement and was US$29 million higher in 2020 compared to 2019 mainly due to new projects placed in service.

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 2022 is expected to be consistent with 2021. This is due to, among other factors, an expected increase in transportation rates on ANR subject to the outcome of the Section 4 rate case filed with FERC, completion of expansion projects in 2021 and 2022 on the ANR and Columbia Gulf systems as well as higher revenues on Columbia Gas due to the full-year implementation of higher transportation rates as part of the uncontested Section 4 rate case settlement filed with FERC. Our pipeline systems continue to see historically strong demand for service and we anticipate our assets will maintain the high utilization levels experienced in 2021. These positive results are expected to be partially offset by higher operational costs and an anticipated increase in property taxes from capital projects placed in service.

Capital spending

We spent a total of US$2.2 billion in 2021 on our U.S. natural gas pipelines and expect to spend approximately US$1.6 billion in 2022 primarily on ANR expansion projects and our 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.

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

Tula and Villa de Reyes

The CFE initiated arbitration in June 2019 for the Tula and Villa de Reyes projects, disputing fixed capacity payments due to force majeure events. Arbitration proceedings are currently suspended while management holds settlement discussions with the CFE. In 2021, we advanced the resolution of disputed contract terms with the signing of an MOU on July 30, 2021 outlining main settlement principles.

Villa de Reyes construction is ongoing but completion has been delayed due to COVID-19 contingency measures and challenges gaining access to land in certain local communities. Management is working closely with state and local governments to complete negotiations and achieve access to land so that construction can be completed. We expect to complete the construction of Villa de Reyes in phases during 2022.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (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$, unless otherwise noted)	**2021**	**2020**	**2019**
Topolobampo	**161**	159	159
Sur de Texas[1]	**113**	171	43
Tamazunchale	**118**	120	120
Guadalajara	**71**	64	65
Mazatlán	**70**	70	70
Comparable EBITDA	**533**	584	457
Depreciation and amortization	**(86)**	(87)	(87)
Comparable EBIT	**447**	497	370
Foreign exchange impact	**110**	172	120
Comparable EBIT and segmented earnings (Cdn$)	**557**	669	490

1 Represents equity income from our 60 per cent interest and fees earned from the construction and operation of the pipeline.

Mexico Natural Gas Pipelines segmented earnings in 2021 decreased by $112 million compared to 2020 and increased by $179 million in 2020 compared to 2019. A weaker U.S. dollar in 2021 had a negative impact on the Canadian dollar equivalent segmented earnings from our Mexico operations compared to the same period in 2020, while a stronger U.S. dollar in 2020 had a positive impact on the Canadian dollar equivalent segmented earnings from our Mexico operations compared to the same period in 2019.

Comparable EBITDA for Mexico Natural Gas Pipelines decreased by US$51 million in 2021 compared to 2020 mainly due to:

- decreased Sur de Texas equity income due to one-time fees of US$55 million recognized in 2020 associated with the construction of the project
- higher earnings from Guadalajara following the implementation of a flow reversal project completed in 2020.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$127 million in 2020 compared to 2019 mainly due to:

- increased Sur de Texas equity income from the commencement of transportation services in September 2019
- revenues of US$55 million recognized in 2020 from fees associated with the construction of the Sur de Texas pipeline as well as ongoing fees earned from operating the pipeline.

Prior to in-service, Sur de Texas equity income primarily reflected AFUDC during construction, net of our proportionate share of interest expense on peso-denominated inter-affiliate loans. These inter-affiliate loans remain in place and our share of related interest expense in Sur de Texas continues to be fully offset by corresponding interest income recorded in Interest income and other in the Corporate segment.

Depreciation and amortization

Depreciation and amortization in 2021 was consistent with the same periods in 2020 and 2019.

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 into service. Comparable EBITDA for 2022 is expected to be higher than 2021 due to the anticipated settlement of the disputed contract terms with the CFE and the expected in-service of Villa de Reyes during 2022.

Capital spending

We spent a total of US$0.1 billion in 2021 primarily related to the construction of the Villa de Reyes pipeline, maintenance of constructed Tula segments and life-cycle enhancements to existing assets. Capital spending in 2022 to complete construction of Villa de Reyes and additional life-cycle asset investments is expected to be US$0.1 billion.

NATURAL GAS PIPELINES – BUSINESS RISKS

The following are risks specific to our Natural Gas Pipelines business. Refer to page 93 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.

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 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 the development of rate, facility and tariff applications that account for and mitigate the 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 existing liquids pipelines infrastructure connects Alberta crude oil supplies to U.S. refining markets in Illinois, Oklahoma and the U.S. Gulf Coast as well as U.S. crude oil supplies from the key market hub at Cushing, Oklahoma to the U.S. Gulf Coast. We also provide intra-Alberta liquids transportation.

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 – over 460 km (290 miles).

Strategy

Optimize the value of our existing Liquids Pipelines assets, while operating safely and reliably. We also pursue emerging growth opportunities to add incremental value to our business. In support of our GHG emissions reduction targets, we are taking significant steps to source renewable power for our operations. The strategy addresses scope two emissions, which are primarily generated by the consumption of electricity used to power our liquids pipelines.

Recent highlights

- U.S. President Biden revoked the existing Presidential Permit for the Keystone XL pipeline project on January 20, 2021. As a result, we terminated the Keystone XL pipeline project
- submitted 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
- received $35 million in proceeds from the monetization of our remaining interest in Northern Courier
- entered into a joint venture with Motiva Enterprises (Motiva) to construct the US$152 million Port Neches Link pipeline system. Construction has commenced and is expected to be in service in mid-2022.


TC Energy
Liquids Pipelines
As at December 31, 2021
Liquids Pipeline
In Development/Construction
Liquids Tank Terminal
Production Basin
Western Canadian Sedimentary Basin
Oil Sands
4
3
5
CANADA
CALGARY
Williston
TORONTO
1
Powder River
Denver-Julesburg
UNITED STATES
CHARLESTON
Anadarko
2
Permian
HOUSTON
Eagle Ford
MEXICO
MEXICO CITY

We are the operator and developer of the following:

		Length	Description	Ownership
	Liquids pipelines			
1	Keystone Pipeline System	4,324 km (2,687 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 (287 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 %
	In development			
5	Grand Rapids Phase II	460 km (287 miles)	Expansion of Grand Rapids to transport additional crude oil from the producing area northwest of Fort McMurray, Alberta to the Edmonton/Heartland, Alberta market region.	50 %

UNDERSTANDING OUR LIQUIDS PIPELINES BUSINESS

Our Liquids Pipelines segment consists of crude oil and liquids/petroleum products pipelines, complemented by a liquids marketing business. We efficiently transport crude oil from major supply sources to markets where crude oil can be refined into various petroleum products, and offer ancillary services such as short- and long-term storage of liquids at key terminal locations to offer our customers delivery flexibility while optimizing the value of our pipeline assets.

We provide pipeline transportation capacity to customers predominantly supported by long-term contracts with fixed monthly payments that are not linked to actual throughput volumes or to the price of the commodity, generating stable earnings over the contract term. The terms of service and fixed monthly payments are determined by contracts negotiated with customers which provide for the recovery of costs we incur to construct the asset. Generally, the costs to operate and maintain the system are flowed through to customers via a variable-toll mechanism. Uncontracted pipeline capacity is offered to the market to secure additional volumes on a monthly spot basis which provides opportunities to generate incremental earnings. Term storage of liquids at terminals is offered to our customers in return for fixed fee payments which are not linked to actual storage volumes or to the price of the commodity.

The Keystone Pipeline System, our largest liquids pipeline asset, transports approximately 20 per cent of the U.S. Midwest and the U.S. Gulf Coast refiners' demand for Canadian crude oil. It also provides significant capacity between Cushing, Oklahoma and the U.S. Gulf Coast market, primarily transporting U.S. crude oil. Our two intra-Alberta liquids pipelines – Grand Rapids and White Spruce – provide crude oil transportation for producers in northern Alberta.

Our liquids marketing business provides customers with a variety of crude oil marketing services including transportation, storage and crude oil management, 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.

Business environment

Global crude oil and liquids demand continues to be impacted by the COVID-19 pandemic as containment measures imposed by most countries around the world continue to reduce transportation, commercial and non-essential activities. Demand is expected to gradually recover to pre-COVID-19 levels through 2022.

Global crude oil and liquids demand is projected to increase from 97 million Bbl/d in 2021 to 107 million Bbl/d in 2035, driven primarily by the transportation and industrial sectors which account for 80 per cent of total crude oil and liquids demand. Global supply of crude oil necessary to meet this demand is expected to be sourced from countries with significant crude oil reserves, mainly in North America, South America and the Middle East. To meet this demand requirement, a strong crude oil price environment is needed to support continuing investment in the energy sector.

Crude oil prices have recovered from 2020 lows, due to crude oil supply management efforts, primarily by OPEC+, capital discipline of North American producers and global demand growth. The ongoing COVID-19 pandemic, combined with uncertainty over the ability for OPEC+ to manage and meet market requirements, continues to drive crude oil price volatility.

Supply outlook

Canada

Canada has the world's third largest crude oil reserves with over 160 billion barrels of economically and technically recoverable conventional and oil sands reserves, primarily in Alberta. Total 2021 WCSB crude oil production was approximately 4.4 million Bbl/d and is expected to increase to approximately 5.2 million Bbl/d by 2035, subject to the resolution of current ex-Alberta pipeline capacity constraints. Oil sands production comprises the majority of western Canadian crude oil supply at approximately 3.2 million Bbl/d and is a favourable supply source given its decades-long reserve life, steady production and rapidly improving cost and environmental performance.

U.S.

The U.S. is one of the largest crude oil producing countries in the world at approximately 11 million Bbl/d in 2021. 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. In recent years, the Permian basin has become the most dominant producing region accounting for approximately 30 per cent of total U.S. crude oil production and is expected to grow to greater than 6 million Bbl/d by 2035.

With light oil processing capacity fully utilized in the U.S., exports to offshore markets are the only outlets for incremental light tight oil production. U.S. crude oil exports have remained strong at close to 3 million Bbl/d in 2021, despite the global demand impact from the COVID-19 pandemic. By 2035, the U.S. is expected to export approximately 4.9 million Bbl/d of predominantly light crude oil and import approximately 4.8 million Bbl/d of heavy crude oil.

Demand outlook

Canada's proximity to the U.S., which is the world's largest consumer of crude oil at greater than 16 million Bbl/d, and Canada's significant heavy crude oil production are of strategic importance to the U.S. refining industry. Many refiners in the U.S. Midwest and U.S. Gulf Coast process a wide variety of crude oil, including significant amounts of heavy crude oil. This flexibility, access to an abundance of low-cost natural gas, proximity to light and heavy crude oil supply, economies of scale and ready access to markets have positioned these refineries to be among the most profitable in the world.

The U.S. Midwest and U.S. Gulf Coast refining markets have a strong reliance on heavy crude oil imports, with total imports of approximately 4 million Bbl/d in 2021. The U.S. Midwest refiners have total refining capacity of approximately 4 million Bbl/d, which requires approximately 1.5 million Bbl/d of heavy crude oil. The U.S. Gulf Coast is the largest regional refining centre in the world with a total capacity close to 10 million Bbl/d, representing more than half of the total U.S. refining capacity. The U.S. Gulf Coast imported over 2 million Bbl/d of primarily heavy crude oil in 2021 to meet demand.

Canada is currently the largest exporter of crude oil to the U.S. at nearly 4 million Bbl/d. Demand for heavy crude oil in the U.S. has been resilient and is expected to remain strong for the foreseeable future. While Canada, Venezuela and Mexico are the top suppliers of heavy crude oil to the U.S., the latter two countries are experiencing declining production. U.S. sanctions, along with the market impacts of the COVID-19 pandemic, have reduced demand for Venezuela's heavy crude oil production. Mexico expects the export of Maya, its flagship heavy crude oil, to continue to fall due to the continued declines in its production and new domestic demand. Approximately 36 per cent of U.S. Gulf Coast heavy crude oil imports are currently met by Mexico which presents a significant opportunity for Canada to become a more prominent supplier of crude oil to the U.S.

Strategic priorities

Our intra-Alberta liquids pipelines and the Keystone Pipeline System strategically position us to provide competitive transportation solutions for growing supplies of Alberta heavy crude oil and U.S. light tight oil to the U.S. Midwest and the U.S. Gulf Coast.

Within our established risk preferences, we remain committed to:
- optimizing the value and competitiveness of our existing assets
- expanding and leveraging our existing infrastructure
- expanding the transportation services that we offer and extending into adjacent geographies
- extending into emerging growth opportunities.

COVID-19 has had a material impact on energy markets by disrupting and delaying industry growth. The long-term contract profile supporting our business model provides stability for our existing businesses but growth will likely be challenged until energy markets normalize. The cyclical nature of commodity prices may influence the pace at which our customers expand their operations. This can impact the rate of project growth in our industry, the value of our services as contracts expire and the timing for the demand of transportation services and/or new liquids infrastructure.

Within Alberta, we continue to position ourselves to capture WCSB production growth. Declining Latin American crude oil production has increased the demand for WCSB heavy crude oil in the U.S. Gulf Coast, which has historically relied on offshore imports.

With the fast-paced growth of U.S. light tight oil production and fully satisfied demand for light oil in North America, we will examine opportunities to expand our transportation services and extend our pipeline platform to include terminals with storage and marine export capabilities. Terminal connections and storage facilities encourage flows into and out of our pipeline systems, which we expect will help to secure long-term contracts and incremental spot volumes. We will also focus on leveraging our existing assets and development of projects to reach emerging growth regions such as the Williston and Denver-Julesburg basins.

We believe our liquids pipelines business is well positioned to endure the impact of short-term commodity price fluctuations and supply/demand responses. Our existing operations and development projects are supported by long-term contracts where we provide pipeline capacity to our customers in exchange for fixed monthly payments which are not affected by commodity prices or throughput. We continually work with existing and potential customers to provide pipeline transportation and terminal services. The combination of the scale and location of our assets assists us in attracting additional volumes and in growing our business.

We closely monitor the marketplace for strategic asset acquisitions or joint venture 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.

ESG considerations form an important part of our strategy. Our Liquids Pipelines assets can underpin our de-carbonization goals and present opportunities to create partnerships with Indigenous communities. Our GHG reduction strategy in Liquids Pipelines is to competitively source renewable energy to power our base operating systems and reduce our carbon footprint with a goal of reducing 99 per cent of our liquids pipelines' scope two GHG emissions from our operations by 2025 and achieving net-zero emissions by 2030. We also seek to develop partnerships with Indigenous communities that will create value and further enable participation in energy infrastructure by those partners.

SIGNIFICANT EVENTS

Keystone XL

Following the revocation of the Presidential Permit for the Keystone XL pipeline project on January 20, 2021, and after a comprehensive review of options in consultation with our partner, the Government of Alberta, on June 9, 2021, we terminated the Keystone XL pipeline project.

The Keystone XL investment was evaluated for impairment in 2021 along with our investments in related capital projects including Heartland Pipeline, TC Terminals and Keystone Hardisty Terminal. We determined that the carrying amount of these assets was no longer fully recoverable. As a result, we 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 ended December 31, 2021 which was excluded from comparable earnings. The asset impairment charge was based on the excess of the carrying value of the asset of $3.3 billion over the estimated fair value of $175 million, net of contractual recoveries of $693 million and contractual and legal obligations related to termination activities of $342 million.

Termination activities and related costs will continue through 2022 with any adjustments to the estimated fair value and future contractual and legal obligations expensed as determined and excluded from comparable earnings. Refer to Note 6, Keystone XL, of our 2021 Consolidated financial statements for additional information.

Although we recorded a $2.1 billion after-tax asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations related to the Keystone XL pipeline project termination activities, a significant portion of this amount was shared with the Government of Alberta, thereby reducing the net financial impact to us. In June 2021, Class A Interests previously issued to the Government of Alberta totaling $394 million were repurchased for a nominal amount, the $1.0 billion (US$849 million) balance on the project-level credit facility was fully paid by the Government of Alberta and $91 million of Class C Interests were issued to the Government of Alberta entitling them to future liquidation proceeds from specified Keystone XL project assets. After considering these transactions, including the income tax impact thereon, the net financial impact to us as a result of the termination of Keystone XL and related projects at December 31, 2021 was $1.0 billion determined as follows:

(millions of $)	2021
Asset impairment charge and other (after tax)[1]	**2,134**
Government of Alberta Class A Interests repurchased for a nominal amount[2]	**(394)**
Credit facility balance – guaranteed and paid by the Government of Alberta (net)[2,3]	**(737)**
Net financial impact of the termination of the Keystone XL pipeline project	**1,003**

1 Refer to Note 6, Keystone XL, of our 2021 Consolidated financial statements for additional information.
2 Recognized through the Consolidated statement of equity.
3 Net of income taxes and Class C Interests issued.

After the Presidential Permit was revoked, construction activities ceased except for certain activities required to clean up and reclaim worksites in adherence to 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 2022. We will coordinate with regulators, stakeholders and Indigenous groups to meet our environmental and regulatory commitments and ensure a safe exit from the Keystone XL pipeline project. The majority of these associated costs were funded through a final drawdown on the project-level credit facility which occurred in June 2021, subsequent to which the project-level credit facility was fully repaid by the Government of Alberta and terminated.

We continue to manage legacy challenges to the Presidential Permit and the Bureau of Land Management Grant of Right-of-Way, which remain pending before the federal district court in Montana in a manner consistent with the termination of the project.

On November 22, 2021, we filed a Request for Arbitration to formally initiate a legacy NAFTA claim to recover economic damages resulting from the revocation of the Presidential Permit for the Keystone XL pipeline project. We will be seeking to recover more than US$15 billion in damages as a result of the U.S. Government's breach of its NAFTA obligations. This claim is in a preliminary stage with the timing and ultimate outcome unknown at present.

Northern Courier

On November 30, 2021, we received $35 million in proceeds from the monetization of our remaining 15 per cent equity interest in Northern Courier to Astisiy Limited Partnership, a partnership comprised of Suncor Energy Inc. and eight Indigenous communities in the Regional Municipality of Wood Buffalo. As a result, we recorded a pre-tax gain on sale of $13 million ($19 million after tax). The pre-tax gain was included in Net gain/(loss) on assets sold/held for sale in the Consolidated statement of income.

Port Neches

On March 8, 2021, we entered a joint venture with Motiva to construct the US$152 million Port Neches Link pipeline system which will 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 will also include facilities to tie in additional liquids terminals to the Keystone Pipeline System with other downstream infrastructure and is expected to be in service in the second half of 2022.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented (losses)/earnings (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 $)	2021	2020	2019
Keystone Pipeline System	**1,281**	1,474	1,654
Intra-Alberta pipelines[1]	**87**	92	137
Liquids marketing and other	**158**	134	401
Comparable EBITDA	**1,526**	1,700	2,192
Depreciation and amortization	**(318)**	(332)	(341)
Comparable EBIT	**1,208**	1,368	1,851
Specific items:			
Keystone XL asset impairment charge and other	**(2,775)**	—	—
Keystone XL preservation and other	**(43)**	—	—
Gain on sale of Northern Courier	**13**	—	69
Risk management activities	**(3)**	(9)	(72)
Segmented (losses)/earnings	**(1,600)**	1,359	1,848
Comparable EBITDA denominated as follows:			
Canadian dollars	**417**	418	442
U.S. dollars	**884**	955	1,318
Foreign exchange impact	**225**	327	432
Comparable EBITDA	**1,526**	1,700	2,192

1 Intra-Alberta pipelines included Grand Rapids, White Spruce and Northern Courier. In July 2019, we sold an 85 per cent interest in Northern Courier, subsequent to which we applied equity accounting to our remaining 15 per cent investment. In November 2021, we sold the remaining 15 per cent interest in Northern Courier.

Liquids Pipelines segmented earnings decreased by $3.0 billion in 2021 compared to 2020 and decreased by $489 million in 2020 compared to 2019 and included the following specified items which have been excluded from our calculation of comparable EBIT:

- a $2.8 billion pre-tax asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, in 2021 associated with the termination of the Keystone XL pipeline project and related projects following the January 20, 2021 revocation of the Presidential Permit. Refer to the Liquids Pipelines – Significant events section for additional information
- pre-tax preservation and other costs in 2021 of $43 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
- pre-tax gain of $13 million related to the sale of the remaining 15 per cent interest in Northern Courier in 2021 and $69 million related to the sale of an 85 per cent interest in Northern Courier in 2019
- unrealized gains and losses from changes in the fair value of derivatives related to our liquids marketing business.

A weaker U.S. dollar in 2021 had a negative impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2020, while a stronger U.S. dollar in 2020 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2019.

Comparable EBITDA for Liquids Pipelines was $174 million lower in 2021 compared to 2020 primarily due to the net effect of:

- lower volumes on the U.S. Gulf Coast section of the Keystone Pipeline System
- increased contributions from liquids marketing activities mainly attributable to higher margins and volumes.

Comparable EBITDA for Liquids Pipelines was $492 million lower in 2020 compared to 2019 primarily due to:

- lower volumes on the Keystone Pipeline System and lower contribution from liquids marketing activities driven by a global reduction in crude oil demand and prices due to the significant impact of the COVID-19 pandemic in 2020 and disruption to energy markets
- decreased earnings as a result of the sale of an 85 per cent equity interest in Northern Courier in July 2019.

Depreciation and amortization

Depreciation and amortization was $14 million lower in 2021 compared to 2020 primarily as a result of a weaker U.S. dollar. Depreciation and amortization was $9 million lower in 2020 compared to 2019 reflecting the sale of an 85 per cent equity interest in Northern Courier, partially offset by a stronger U.S. dollar.

OUTLOOK

Comparable EBITDA

Comparable EBITDA in 2022 is expected to be lower than 2021 for both the Keystone Pipeline System and liquids marketing business as a result of continuing lower volumes on the U.S. Gulf Coast section of the Keystone Pipeline System and decreased margins, respectively. As discussed in the Understanding our Liquids Pipelines business section, global crude oil demand continues to be impacted by the COVID-19 pandemic but is expected to gradually recover to pre-COVID-19 levels through 2022.

Capital spending

We spent a total of $0.2 billion in 2021 primarily related to capital projects in the U.S. Gulf Coast and on our operating pipelines and expect to spend approximately $0.2 billion in 2022.

BUSINESS RISKS

The following are risks specific to our Liquids Pipelines business. Refer to page 93 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 to ensure transportation services are provided safely and reliably as well as optimizing and maintaining their availability are essential to the success of our business. Interruptions in our pipeline operations may impact our throughput capacity and result in reduced fixed payment revenues and spot volume opportunities. We manage these risks and any possible impact to the local communities and environment by investing in a highly skilled workforce and operating prudently using risk-based preventive maintenance programs and making effective capital investments. We use internal inspection equipment to check our pipelines regularly and repair them whenever necessary.

Regulatory and government

Decisions by Canadian and U.S. regulators can have a significant impact on the approval, construction, operation, commercial and financial performance of our liquids pipelines. Shifts in government policy by existing bodies or following changes in government can impact our ability to grow our business. Public opinion about crude oil development and production, particularly in light of climate change concerns, may also have an adverse impact on the regulatory process. In conjunction with this, there are individuals and special interest groups that are expressing opposition to crude oil production 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 developments and decisions to determine their possible impact on our liquids pipelines business by building scenario analysis into our strategic outlook 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 crude oil products could adversely impact the price that crude oil producers receive for their product. In the long term, lower crude oil prices could mean producers may 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 refining and export markets, we face competition from other midstream companies which also seek to transport these crude oil and diluent supplies to the same markets. Our success is 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 crude oil management, 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 – Enterprise risk management section.

Shifting political trends and ESG requirements

North American governments are attempting to improve their environmental standards and position climate action as a key priority. Meanwhile, the business environment is also evolving quickly as investors demand greater ESG commitments. While there is downside risk to policies that shift support away from our traditional services, there are also opportunities to reduce GHG emissions and generate associated renewable energy and carbon credits for TC Energy.

Power and Storage

Our power business includes approximately 4,300 MW of generation capacity located in Alberta, Ontario, Québec and New Brunswick, using natural gas and nuclear fuel sources and is generally supported by long-term contracts. Additionally, we are pursuing generation assets and PPA opportunities in Canada and the United States.

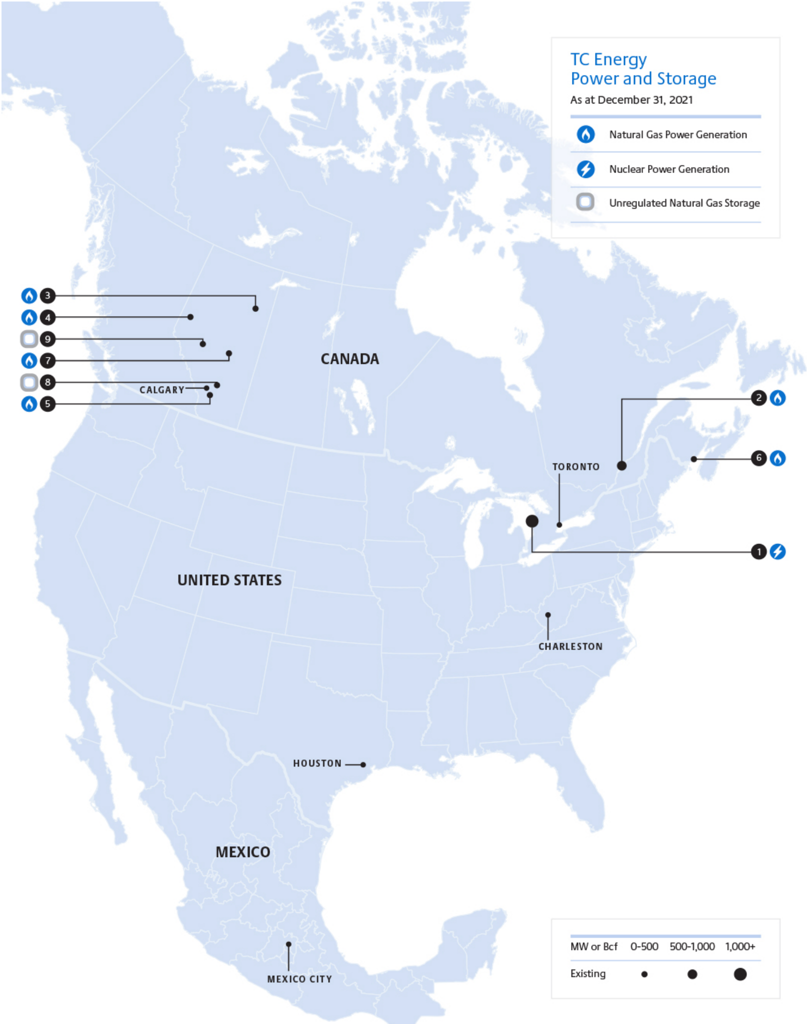
We own and operate approximately 118 Bcf of non-regulated natural gas storage capacity in Alberta.

Strategy

Our strategy is to leverage TC Energy's competitive footprint as a platform to grow our power business and enhance the life cycle and reliability of our assets, all driven by internal and external customer needs. Long term, we believe there will be a growing need for a reliable supply of resources as the energy transition unfolds. We can play a vital role in the energy transition by sourcing zero-carbon growth opportunities, new technologies and markets while decarbonizing our existing assets.

Recent highlights

- further advanced the Bruce Power life extension program with the submission of the final cost and schedule duration estimate to the IESO for the Unit 3 MCR while the Unit 6 MCR project proceeded on budget and schedule
- executed a 15-year PPA for 100 per cent of the power produced and associated environmental attributes from the 297 MW Sharp Hills Wind Farm located in Alberta, which is anticipated to begin operation in 2023
- continued to progress the development of the 1,000 MW clean energy Ontario Pumped Storage Project on federal lands, subject to conditions and regulatory approval
- the Claresholm Solar facility came into service commencing our eight-year PPA and adding 74 MW to our portfolio
- completed the purchase of the remaining interests in the Canyon Creek Pumped Storage project giving us full ownership.


TC Energy
Power and Storage
As at December 31, 2021
Natural Gas Power Generation
Nuclear Power Generation
Unregulated Natural Gas Storage
CANADA
CALGARY
TORONTO
UNITED STATES
CHARLESTON
HOUSTON
MEXICO
MEXICO CITY
MW or Bcf 0-500 500-1,000 1,000+
Existing
1
2
3
4
5
6
7
8
9

Power and Storage assets currently have a combined power generation capacity, net to TC Energy, of 4,258 MW and we operate each facility except for Bruce Power.

		Generating capacity (MW)	Type of fuel	Description	Ownership
1	Bruce Power[1]	3,170	nuclear	Eight operating reactors in Tiverton, Ontario. Bruce Power leases the nuclear facilities from OPG.	48.4 %
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	Bear Creek	100	natural gas	Cogeneration plant in Grande Prairie, Alberta.	100 %
5	Carseland	95	natural gas	Cogeneration plant in Carseland, Alberta.	100 %
6	Grandview	90	natural gas	Cogeneration plant in Saint John, New Brunswick.	100 %
7	Redwater	46	natural gas	Cogeneration plant in Redwater, Alberta.	100 %
Canadian non-regulated natural gas storage					
8	Crossfield	68 Bcf		Underground facility connected to the NGTL System near Crossfield, Alberta.	100 %
9	Edson	50 Bcf		Underground facility connected to the NGTL System near Edson, Alberta.	100 %

1 Our share of power generation capacity.

UNDERSTANDING OUR POWER AND STORAGE BUSINESS

Our Power and Storage business is made up of two groups:

- Power
- Natural Gas Storage (Canadian, non-regulated).

Power

Canadian Power

We own or have the rights to approximately 1,100 MW of power supply in Canada, excluding our investment in Bruce Power. In Alberta we own four natural gas-fired cogeneration facilities and 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 also enables us to capture opportunities to increase earnings in periods of high spot prices. Our two eastern Canadian natural gas-fired cogeneration assets are supported by long-term contracts.

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 6,550 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 48.4 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. Bruce Power also markets and trades power in Ontario and neighbouring jurisdictions under strict risk controls.

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 January 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 to 35 years of operational life to each of the six units.

The Unit 6 MCR is the first of the six-unit MCR life extension program. This outage commenced in January 2020 and is expected to be completed on schedule and on budget. The second unit in the MCR program is Unit 3 and the final cost and schedule duration estimate for Unit 3 was submitted to the IESO in December 2021. The Unit 3 MCR is scheduled to proceed in 2023 and has an expected completion in 2026. Investments in the remaining four 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. In 2021, Bruce Power launched Project 2030 with 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 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.

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. Approximately $200 million was paid to the IESO from 2019 to 2021 in respect to the operating and cost efficiencies realized in the 2016 to 2018 period, with our share being approximately $100 million. No operating and 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 is being undertaken with a Canadian-based nuclear medicine partnership and the Saugeen Ojibway Nation, on whose traditional territory the Bruce Power facilities are located.

U.S. Power

Our U.S. power and emissions commercial trading and marketing business provides our customers with various physical and financial products with a measured approach to our risk management and a focus on financial discipline, compliance and operational excellence.

Power Purchase Agreements

We have secured approximately 400 MW of wind and solar generation PPAs and associated environmental attributes in Alberta as of December 31, 2021. These PPAs allow us to generate incremental earnings while also contributing to the reduction of our operational GHG intensity and allowing us to offer renewable power products to our customers.

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 into 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

Sharp Hills Wind Power Purchase Agreement

On September 20, 2021, we executed a 15-year PPA for 100 per cent of the power produced and the rights to all environmental attributes from the 297 MW Sharp Hills Wind Farm located in eastern Alberta. The Sharp Hills Wind Farm is anticipated to be operational in 2023, subject to customary regulatory approvals and conditions.

Bruce Power Outage

In mid-2021, as part of the planned inspections, testing, analysis and maintenance activities at Bruce Power during the current 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. On October 9, 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. Bruce Power will be incorporating additional inspections as part of their normal surveillance programs to address the new 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 on January 23, 2022.

Bruce Power Life Extension

The Unit 6 MCR program continues on schedule and on budget; however, COVID-19 may have an impact on cost and schedule contingency. As applicable, Bruce Power will seek recovery of any impacts in accordance with the force majeure provisions of the IESO contract. The program is nearing the end of the Inspection Phase and has entered the Installation Phase. Preparation of the Unit 3 MCR program, which is the next scheduled MCR outage, continues and Bruce Power submitted its final cost and schedule duration estimate to the IESO in December 2021. As well, Bruce Power submitted its initial preliminary cost and schedule duration estimate for the Unit 4 MCR program, which is the next unit scheduled after Unit 3.

Bruce Power Uprate Initiative

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.

Ontario Pumped Storage Project

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 Ontario Pumped Storage project, an energy storage facility located near Meaford, Ontario that would provide 1,000 MW of flexible, clean energy to Ontario's electricity system using a process known as pumped hydro storage.

Two key milestones on the Ontario Pumped Storage project were reached in 2021. On July 28, 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. On November 11, 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 will store emission-free energy when available and provide it 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.

Renewable Energy Request for Information

Through an RFI process 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 to meet the electricity needs of the U.S. portion of the Keystone Pipeline System assets. 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. We received a significant number of responses to our RFI and are currently evaluating proposals and expect to finalize contracts during the first half of 2022.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (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 $)	2021	2020	2019
Bruce Power[1]	**411**	439	527
Canadian Power[2]	**253**	213	285
Natural Gas Storage and other	**19**	25	20
Comparable EBITDA	**683**	677	832
Depreciation and amortization	**(78)**	(67)	(95)
Comparable EBIT	**605**	610	737
Specific items:			
Gain/(loss) on sale of Ontario natural gas-fired power plants	**17**	(414)	(279)
Gain on sale of Coolidge generating station	**—**	—	68
U.S. Northeast power marketing contracts	**—**	—	(8)
Risk management activities	**6**	(15)	(63)
Segmented earnings	**628**	181	455

1 Includes our share of equity income from Bruce Power.
2 Includes our Ontario natural gas-fired power plants until sold in April 2020 and Coolidge generating station until sold in May 2019.

Power and Storage segmented earnings increased by $447 million in 2021 compared to 2020 and decreased by $274 million in 2020 compared to 2019 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- 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 (pre-tax loss 2020 – $414 million; 2019 – $279 million)
- a pre-tax gain of $68 million related to the sale of the Coolidge generating station in May 2019
- a pre-tax loss in 2019 of $8 million related to our remaining U.S. Northeast power marketing contracts which were sold in May 2019
- unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks.

Comparable EBITDA for Power and Storage increased by $6 million in 2021 compared to 2020 primarily due to the net effect of:

- increased Canadian Power earnings primarily due to higher realized margins in 2021, contributions from trading activities and a full of year of earnings from our MacKay River cogeneration facility following its return to service in May 2020, partially offset by the sale of our Ontario natural gas-fired power plants in April 2020
- decreased Bruce Power contribution as a result of increased operating expenses and lower volumes resulting from greater planned outage days, partially offset by higher realized prices and gains on funds invested for post-retirement benefits as well as lower financial charges. Additional financial and operating information on Bruce Power is provided below
- decreased Natural Gas Storage and other earnings as a result of increased business development activities across the segment, partially offset by higher realized Alberta natural gas storage spreads in 2021.

Comparable EBITDA for Power and Storage decreased by $155 million in 2020 compared to 2019 primarily due to the net effect of:

- the planned removal from service of Bruce Power Unit 6 in January 2020 for its MCR program, partially offset by fewer planned and unplanned outage days on the remaining units as well as the effects of a higher realized power price. Additional financial and operating information on Bruce Power is provided below
- lower Canadian Power earnings largely as a result of the sale of our Ontario natural gas-fired power plants in April 2020. In addition, we sold our Coolidge generating station in May 2019.

Depreciation and amortization

Depreciation and amortization increased by $11 million in 2021 compared to 2020 primarily due to incremental TC Turbines depreciation following the November 2020 acquisition of the remaining 50 per cent ownership interest as well as other adjustments in 2020. Depreciation was $28 million lower in 2020 compared to 2019 primarily due to the cessation of depreciation on our Halton Hills power plant in July 2019.

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)	**2021**	**2020**	**2019**
Equity income included in comparable EBITDA and EBIT comprised of:			
Revenues[1]	**1,656**	1,681	1,746
Operating expenses	**(922)**	(884)	(883)
Depreciation and other	**(323)**	(358)	(336)
Comparable EBITDA and EBIT[2]	**411**	439	527
Bruce Power – other information			
Plant availability[3,4]	**86 %**	88 %	84 %
Planned outage days[4]	**321**	276	393
Unplanned outage days	**22**	36	58
Sales volumes (GWh)[2]	**20,542**	20,956	22,669
Realized power price per MWh[5]	**$80**	$80	$76

1 Net of amounts recorded to reflect operating cost efficiencies shared with the IESO.
2 Represents our 48.4 per cent ownership interest in Bruce Power. Sales volumes include deemed generation and Unit 6 output until January 2020 when its MCR program commenced.
3 The percentage of time the plant was available to generate power, regardless of whether it was running.
4 Excludes Unit 6 MCR outage days.
5 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.

Plant availability in 2021, excluding the Unit 6 MCR, was 86 per cent as planned maintenance on Units 1 and 3 was completed in 2021 while planned maintenance on Unit 7 commenced in fourth quarter 2021 and returned to service on January 23, 2022.

Excluding the Unit 6 MCR which commenced in January 2020, plant availability in 2020 was 88 per cent as planned maintenance was completed on Units 3, 4, 5 and 8. Plant availability in 2019 was 84 per cent as planned maintenance was completed on Units 2, 3, 5 and 7.

OUTLOOK

Comparable EBITDA

Power and Storage comparable EBITDA in 2022 is expected to be generally consistent with 2021. Bruce Power equity income in 2022 is expected to be similar to 2021 as the impact of its contract price increase for the Unit 3 MCR program is expected to be offset by greater non-MCR planned outage days and operating costs in 2022. Planned maintenance is currently scheduled for Units 1 to 5 in the first half of 2022 and for Unit 4 in the second half of 2022 while the planned outage on Unit 7, which began in fourth quarter 2021, was completed on January 23, 2022. The average 2022 plant availability percentage, excluding Unit 6 which continues its MCR program, is expected to be in the low-80 per cent range.

Capital spending

We invested $0.8 billion in 2021 for our share of Bruce Power's life extension and other maintenance capital projects across the segment and expect to invest approximately $0.9 billion in 2022.

BUSINESS RISKS

The following are risks specific to our Power and Storage business. Refer to page 93 for information about general risks related to TC Energy as a whole, including other operational, safety and financial risks. The Power and Storage marketing business complies with our risk management policies which are described in the Other information – Enterprise risk management section.

Fluctuating power and natural gas market prices

Much of the physical power generation and fuel used in our Alberta 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 storage business. Unexpected outages or extended planned outages at our power plants can increase maintenance costs, lower plant output and sales revenues and lower capacity payments 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 both 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. Extreme weather can also 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 Alberta and Ontario as well as in the development of greenfield power plants. Traditional and non-traditional players 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.

Corporate

COVID-19

Amid the ongoing adaptations and restrictions in place as a result of the COVID-19 pandemic, we continue to effectively operate our assets, conduct commercial activities and execute on projects with a focus on health, safety and reliability. While it remains premature to ascertain any long-term impact that COVID-19 may have on our capital program, we continue to observe some slowdown on certain of our construction activities and capital expenditures. In addition, supply chain impacts are manifesting with rising costs for certain commodities and labour shortages in some areas which can cause cost increases and slower progress than anticipated. Further details for capital projects more significantly impacted by COVID-19 are described within the different business segment sections.

The degree to which COVID-19 has a more pronounced longer-term impact on our operations and growth projects will depend on future developments, policies and actions, all of which remain somewhat uncertain. Additional information regarding the risks, uncertainties and impact on our business from COVID-19 can be found throughout this MD&A including the Capital program, Outlook and the Financial risks sections.

SIGNIFICANT EVENTS

Alberta Carbon Grid

On June 17, 2021, we announced a partnership with Pembina Pipeline Corporation to jointly develop a world-scale carbon transportation and sequestration system which, when fully constructed, will be capable of transporting more than 20 million tonnes of carbon dioxide annually, thereby providing opportunities to retrofit existing assets and reduce our carbon footprint. By leveraging existing pipelines and a newly developed sequestration hub, the ACG is expected to provide an infrastructure platform for Alberta-based industries to manage their emissions and contribute to a lower-carbon economy. Designed to be an open-access system, the ACG would connect the Fort McMurray, Alberta Industrial Heartland and Drayton Valley regions to key sequestration locations and delivery points across the province. We are also pursuing opportunities to leverage our existing systems in support of hydrogen production and transportation.

Irving Oil Decarbonization

On August 12, 2021, we signed an MOU to explore the joint development of a series of proposed energy projects focused on reducing GHG emissions and creating new economic opportunities in New Brunswick and Atlantic Canada. Together with Irving Oil, we have identified a series of potential projects focused on decarbonizing existing assets and deploying emerging technologies to reduce overall emissions over the medium and long term. The partnership's initial focus will consider a suite of upgrade projects at Irving Oil's refinery in Saint John, New Brunswick, with the goal of significantly reducing emissions through the production and use of low-carbon power generation.

Hydrogen Hubs

We have entered into two JDAs, to support customer-driven hydrogen production for long-haul transportation, power generation, large industrials and heating customers across the United States and Canada. The first opportunity is a partnership with Nikola Corporation, a designer and manufacturer of zero-emission battery-electric and hydrogen-electric vehicles and related equipment, where Nikola will be a long-term anchor customer for hydrogen production infrastructure supporting hydrogen fueled zero-emission heavy-duty trucks. The JDA with Nikola supports co-development of large-scale green and blue hydrogen production hubs, utilizing our power and natural gas infrastructure.

Our second customer-driven opportunity is a partnership with Hyzon Motors, a leader in fuel cell electric mobility for commercial vehicles, to develop hydrogen production facilities focused on zero-to-negative carbon intensity hydrogen from renewable natural gas, biogas and other sustainable sources. The facilities will be located close to demand, supporting Hyzon's back-to-base vehicle deployments. 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.

Voluntary Retirement Program

In mid-2021, we offered a one-time VRP to eligible employees. Participants in the program retired by December 31, 2021 and received a transition payment in addition to existing retirement benefits. In 2021, we expensed a total of $81 million before income tax, mainly related to the VRP transition payments, which was included in Plant operating costs and other. Of the total program costs, $63 million was excluded from comparable earnings and $18 million was recorded in Revenues related to costs that are recoverable through regulatory and tolling structures on a flow-through basis.

Acquisition of Common Units of TC PipeLines, LP

On March 3, 2021, we completed the acquisition of all of the outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy, resulting in TC PipeLines, LP becoming an indirect, wholly-owned subsidiary of TC Energy. Upon close of the transaction and in accordance with the acquisition terms, TC PipeLines, LP common unitholders received 0.70 common shares of TC Energy for each issued and outstanding publicly-held TC PipeLines, LP common unit resulting in the issuance of 38 million TC Energy common shares valued at approximately $2.1 billion, net of transaction costs. Refer to Note 22, Common shares, of our 2021 Consolidated financial statements for additional information.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to Corporate segmented (losses)/earnings (the most directly comparable GAAP measure). Refer to page 11 for more information on non-GAAP measures we use.

ar ended December 31 illions of $)	2021	2020	2019
mparable EBITDA and EBIT	**(24)**	(16)	(17)
ecific items:			
'oluntary Retirement Program	**(63)**	—	—
'oreign exchange gains/(losses) – inter-affiliate loans[1]	**41**	86	(53)
gmented (losses)/earnings	**(46)**	70	(70)

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

Corporate segmented losses in 2021 increased by $116 million from segmented earnings of $70 million in 2020 to segmented losses of $46 million in 2021. Segmented earnings increased by $140 million in 2020 compared to segmented losses of $70 million in 2019.

Corporate segmented (losses)/earnings included pre-tax costs for the VRP offered in mid-2021 as well as foreign exchange gains and losses on our proportionate share of peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners. These foreign exchange gains and losses are recorded in Income from equity investments in the Corporate segment and have been excluded from our calculation of comparable EBITDA and EBIT as they are fully offset by corresponding foreign exchange losses and gains on the inter-affiliate loan receivable included in Interest income and other. Refer to the Corporate – Significant events section for additional information on the VRP and Other Information – Related party transactions section for additional information on our peso-denominated inter-affiliate loans.

Comparable EBITDA and EBIT for Corporate decreased by $8 million in 2021 compared to 2020. The decrease was primarily due to a U.S. capital tax adjustment recorded in 2020. Comparable EBITDA for Corporate in 2020 was consistent with 2019.

OTHER INCOME STATEMENT ITEMS

Interest expense

year ended December 31 (millions of $)	2021	2020	2019
Interest on long-term debt and junior subordinated notes			
Canadian dollar-denominated	**(712)**	(685)	(598)
U.S. dollar-denominated	**(1,259)**	(1,302)	(1,326)
Foreign exchange impact	**(320)**	(446)	(434)
	(2,291)	(2,433)	(2,358)
Other interest and amortization expense	**(85)**	(89)	(161)
Capitalized interest	**22**	294	186
Interest expense included in comparable earnings	**(2,354)**	(2,228)	(2,333)
Specific item:			
Keystone XL preservation and other	**(6)**	—	—
Interest expense	**(2,360)**	(2,228)	(2,333)

Interest expense in 2021 increased by $132 million compared to 2020 and included $6 million 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. This has been removed from our calculation of interest expense included in comparable earnings.

Interest expense included in comparable earnings in 2021 increased by $126 million compared to 2020 primarily due to the net effect of:

- lower capitalized interest due to its cessation for the Keystone XL pipeline project following the revocation of the Presidential Permit on January 20, 2021, the change to equity accounting for our Coastal GasLink investment upon the sale of a 65 per cent interest in Coastal GasLink LP in 2020 and the completion of the Napanee power plant in 2020
- the foreign exchange impact from a weaker U.S. dollar on translation of U.S. dollar-denominated interest
- lower interest rates on reduced levels of short-term borrowings
- long-term debt and junior subordinated note issuances, net of maturities. Refer to the Financial condition section for additional information on long-term debt and junior subordinated notes.

Interest expense included in comparable earnings in 2020 decreased by $105 million compared to 2019 mainly due to the net effect of:

- higher capitalized interest largely related to Keystone XL and Coastal GasLink prior to its change to equity accounting upon the sale of a 65 per cent interest in the project in May 2020, partially offset by lower capitalized interest due to the completion of Napanee construction in 2020. The increase of capitalized interest for Keystone XL was largely the result of additional capital expenditures along with the inclusion of previously impaired capital costs in the basis for calculating capitalized interest following the decision to proceed with construction of the pipeline. These legacy costs were not re-capitalized but were included for determining capitalized interest in accordance with GAAP
- lower interest rates on reduced levels of short-term borrowings
- long-term debt issuances, net of maturities
- foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest.

Allowance for funds used during construction

year ended December 31 (millions of $)	2021	2020	2019
Allowance for funds used during construction			
Canadian dollar-denominated	**140**	106	203
U.S. dollar-denominated	**101**	182	205
Foreign exchange impact	**26**	61	67
Allowance for funds used during construction	**267**	349	475

AFUDC decreased by $82 million in 2021 compared to 2020. The increase in Canadian dollar-denominated AFUDC is primarily related to a higher balance of NGTL System expansion projects under construction. The decrease in U.S. dollar-denominated AFUDC is mainly the result of the suspension of recording AFUDC on the Villa de Reyes project effective January 1, 2021 due to ongoing delays and the Columbia Gas BXP project which went into service on January 1, 2021, partially offset by the impact of increased capital expenditures on our U.S. natural gas pipeline projects.

AFUDC decreased by $126 million in 2020 compared to 2019. The lower Canadian dollar-denominated AFUDC in 2020 was mainly due to NGTL System expansion projects placed in service. The decrease in U.S. dollar-denominated AFUDC was primarily the result of the suspension of recording AFUDC on Tula, effective January 1, 2020, due to ongoing construction delays, partially offset by continuing construction of the Villa de Reyes project.

Interest income and other

year ended December 31 (millions of $)	2021	2020	2019
Interest income and other included in comparable earnings	**444**	173	162
Specific items:			
Foreign exchange (losses)/gains – inter-affiliate loan	**(41)**	(86)	53
Risk management activities	**(203)**	126	245
Interest income and other	**200**	213	460

Interest income and other decreased by $13 million in 2021 compared to 2020 and by $247 million in 2020 compared to 2019 and included the following specific items which have been removed from our calculation of Interest income and other included in comparable earnings:

- foreign exchange losses and gains on the peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture
- unrealized gains and losses from changes in the fair value of derivatives used to manage our foreign exchange risk.

Our proportionate share of the corresponding foreign exchange gains and losses and interest expense on the peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners are reflected in Income from equity investments in the Corporate and Mexico Natural Gas Pipelines segments, respectively. The foreign exchange gains and losses on these inter-affiliate loans are removed from comparable earnings while the interest income and interest expense are included in comparable earnings with all amounts offsetting and resulting in no impact on net income. Refer to Other Information – Related party transactions for additional information.

Interest income and other included in comparable earnings increased by $271 million in 2021 compared to 2020 primarily due to the net effect of:

- realized gains in 2021 compared to realized losses in 2020 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- lower interest income in 2021 related to the peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture due to lower interest rates and the foreign exchange impact of a weaker peso on the translation of interest income during the year.

Interest income and other included in comparable earnings increased by $11 million in 2020 compared to 2019 due to the net effect of:

- lower realized losses in 2020 compared to 2019 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- lower interest income in 2020 related to the peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture due to lower interest rates and the foreign exchange impact of a weaker peso on the translation of interest income during the year.

Income tax expense

year ended December 31 (millions of $)	2021	2020	2019
Income tax expense included in comparable earnings	**(833)**	(654)	(898)
Specific items:			
Keystone XL asset impairment charge and other	**641**	—	—
Voluntary Retirement Program	**15**	—	—
Keystone XL preservation and other	**12**	—	—
Sale of Northern Courier	**6**	—	46
Sale of Ontario natural gas-fired power plants	**(10)**	131	85
Income tax valuation allowance releases	**—**	299	195
Partial sale of Coastal GasLink LP	**—**	38	—
Sale of Columbia Midstream assets	**—**	18	(173)
Alberta corporate income tax rate reduction	**—**	—	32
U.S. Northeast power marketing contracts	**—**	—	2
Sale of Coolidge generating station	**—**	—	(14)
Risk management activities	**49**	(26)	(29)
Income tax expense	**(120)**	(194)	(754)

Income tax expense in 2021 decreased by $74 million compared to 2020 and decreased by $560 million in 2020 compared to 2019 and included the specific items noted below which have been removed from our calculation of Income tax expense included in comparable earnings.

In addition, some of the income tax impacts noted in the table above relate to specific items referenced elsewhere in this MD&A. In 2021, all specific items are discussed in their respective business segment disclosure as they did not relate to income tax specific items.

Specific items in 2020:

- income tax valuation allowance releases of $299 million primarily related to the reassessment of deferred tax assets that were deemed more likely than not to be realized as a result of our March 31, 2020 decision to proceed with the Keystone XL pipeline project
- an $18 million income tax recovery related to state income taxes on the sale of certain Columbia Midstream assets.

Specific items in 2019:

- an income tax valuation allowance release of $195 million related to certain prior years' U.S. income tax losses resulting from our reassessment of deferred tax assets that are more likely than not to be realized
- a $32 million income tax recovery on deferred tax balances attributable to our Canadian businesses not subject to RRA due to an Alberta corporate income tax rate reduction enacted in June 2019.

These items were removed from Income tax expense included in comparable earnings in addition to the income tax impacts of the specific items referenced elsewhere in this MD&A.

Income tax expense included in comparable earnings in 2021 increased by $179 million compared to 2020 primarily due to higher flow-through income taxes on Canadian rate-regulated pipelines, increased earnings subject to income tax and the impact of Mexico inflationary adjustments, partially offset by higher foreign tax rate differentials.

Income tax expense included in comparable earnings in 2020 decreased by $244 million compared to 2019 primarily due to lower flow-through income taxes on Canadian rate-regulated pipelines and higher foreign tax rate differentials.

Net income attributable to non-controlling interests

year ended December 31 (millions of $)	**2021**	**2020**	**2019**
Net income attributable to non-controlling interests	**(91)**	(297)	(293)

Net income attributable to non-controlling interests decreased by $206 million in 2021 compared to 2020 primarily as a result of the March 3, 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. Refer to the Corporate – Significant events section and Note 21, Non-controlling interests, of our 2021 Consolidated financial statements for additional information.

In 2020, Net income attributable to non-controlling interests increased by $4 million compared to 2019 primarily due to higher earnings in TC PipeLines, LP, partially offset by the net loss attributable to redeemable non-controlling interest which includes a foreign currency translation loss and return accrual in 2020.

Preferred share dividends

year ended December 31 (millions of $)	**2021**	**2020**	**2019**
Preferred share dividends	**(140)**	(159)	(164)

Preferred share dividends decreased by $19 million in 2021 compared to 2020 primarily due to the redemption of all issued and outstanding Series 13 preferred shares on May 31, 2021. Preferred share dividends of $159 million in 2020 were generally consistent with 2019.

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 to meet our financing needs, manage our capital structure and to preserve our 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.sedar.com).

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, 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.

Balance sheet analysis

At December 31, 2021, our current assets totaled $7.4 billion and current liabilities amounted to $13.0 billion, leaving us with a working capital deficit of $5.6 billion compared to $6.8 billion at December 31, 2020. 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 $10.0 billion of committed revolving credit facilities of which $5.0 billion of short-term borrowing capacity remains available, net of $5.0 billion backstopping outstanding commercial paper balances. We also have arrangements in place for a further $2.4 billion of demand credit facilities of which $1.2 billion remains available as of December 31, 2021
- our access to capital markets, including through securities issuances, incremental credit facilities, portfolio management activities, DRP and Corporate ATM programs, if deemed appropriate.

Our total assets at December 31, 2021 were $104.2 billion compared to $100.3 billion at December 31, 2020 with the increase primarily reflecting our 2021 capital spending program, working capital and equity investments, partially offset by depreciation, the Keystone XL asset impairment and the impact of a weaker U.S. dollar at December 31, 2021 compared to December 31, 2020 on translation of our U.S. dollar-denominated assets.

At December 31, 2021 our total liabilities were $70.8 billion, compared to $66.8 billion at December 31, 2020 due to the net effect of movements in debt, working capital and foreign exchange rates as discussed above.

Our equity at December 31, 2021 was $33.4 billion, consistent with $33.1 billion at December 31, 2020.

Consolidated capital structure

The following table summarizes the components of our capital structure.

at December 31 (millions of $, unless otherwise noted)	2021	Per cent of total	2020	Per cent of total
Notes payable	**5,166**	**6**	4,176	5
Redeemable non-controlling interest[1]	**—**	**—**	633	1
Long-term debt, including current portion	**38,661**	**45**	36,885	45
Cash and cash equivalents	**(673)**	**(1)**	(1,530)	(2)
	43,154	**50**	40,164	49
Junior subordinated notes	**8,939**	**11**	8,498	10
Redeemable non-controlling interest	**—**	**—**	393	1
Preferred shares	**3,487**	**4**	3,980	5
Common shareholders' equity	**29,784**	**35**	27,418	33
Non-controlling interests	**125**	**—**	1,682	2
	85,489	**100**	82,135	100

1 Classified in Current liabilities on the Consolidated balance sheet.

At February 9, 2022, we had unused capacity of $3.0 billion, $1.5 billion, US$4.0 billion and $1.5 billion under our TC Energy equity, TCPL Canadian and U.S. debt and TC Trust hybrid shelf prospectuses, respectively, to facilitate future access to capital markets.

Provisions of various trust indentures and credit arrangements with certain of our subsidiaries can restrict those subsidiaries' 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, 2021.

Cash flows

The following tables summarize our consolidated cash flows.

year ended December 31 (millions of $)	**2021**	**2020**	**2019**
Net cash provided by operations	**6,890**	7,058	7,082
Net cash used in investing activities	**(7,712)**	(6,052)	(6,872)
Net cash (used in)/provided by financing activities	**(88)**	(800)	693
	(910)	206	903
Effect of foreign exchange rate changes on cash and cash equivalents	**53**	(19)	(6)
(Decrease)/increase in cash and cash equivalents	**(857)**	187	897

Cash provided by operating activities

year ended December 31 (millions of $)	**2021**	**2020**	**2019**
Net cash provided by operations	**6,890**	7,058	7,082
Increase/(decrease) in operating working capital	**287**	327	(293)
Funds generated from operations	**7,177**	7,385	6,789
Specific items:			
Current income tax expense on Keystone XL asset impairment charge, preservation and other	**131**	—	—
Keystone XL preservation and other	**49**	—	—
Voluntary Retirement Program	**63**	—	—
Current income tax recovery on Voluntary Retirement Program	**(14)**	—	—
Current income tax expense on sale of Columbia Midstream assets	**—**	—	320
U.S. Northeast power marketing contracts	**—**	—	8
Comparable funds generated from operations	**7,406**	7,385	7,117

Net cash provided by operations

Net cash provided by operations decreased by $168 million in 2021 compared to 2020 primarily due to lower funds generated from operations, partially offset by the amount and timing of working capital changes.

Net cash provided by operations decreased by $24 million in 2020 compared to 2019 primarily due to the amount and timing of working capital changes which was mostly offset by higher funds generated from operations.

Comparable funds generated from operations

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

Comparable funds generated from operations increased by $21 million in 2021 compared to 2020 primarily due to higher comparable earnings, including realized gains in 2021 compared to realized losses in 2020 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income. This was partially offset by fees collected in 2020 associated with the construction of the Sur de Texas pipeline, as well as lower distributions from the operating activities of our equity investments in 2021.

Comparable funds generated from operations increased by $268 million in 2020 compared to 2019 primarily due to collection of fees related to the construction of Sur de Texas and Coastal GasLink, the recovery of higher depreciation on the NGTL System and higher comparable earnings, partially offset by lower distributions from the operating activities of our equity investments.

Cash used in investing activities

year ended December 31 (millions of $)	2021	2020	2019
Capital spending			
Capital expenditures	**(5,924)**	(8,013)	(7,475)
Capital projects in development	**—**	(122)	(707)
Contributions to equity investments	**(1,210)**	(765)	(602)
	(7,134)	(8,900)	(8,784)
Proceeds from sales of assets, net of transaction costs	**35**	3,407	2,398
Loan to affiliate	**(239)**	—	—
Acquisition	**—**	(88)	—
Other distributions from equity investments	**73**	—	186
Payment for unredeemed shares of Columbia Pipeline Group, Inc.	**—**	—	(373)
Deferred amounts and other	**(447)**	(471)	(299)
Net cash used in investing activities	**(7,712)**	(6,052)	(6,872)

Net cash used in investing activities increased from $6.1 billion in 2020 to $7.7 billion in 2021 largely as a result of proceeds received from the sale of assets in 2020, as discussed below, as well as higher contributions to equity investments and a loan issued to one of our affiliates in 2021, partially offset by lower capital spending in 2021.

Net cash used in investing activities decreased from $6.9 billion in 2019 to $6.1 billion in 2020 primarily as a result of proceeds received in 2020 on the sales of our Ontario natural gas-fired power plants and a 65 per cent equity interest in Coastal GasLink LP as well as the payment to dissenting Columbia Pipeline Group, Inc. (Columbia) shareholders in 2019. This was partially offset by the cost to acquire the remaining 50 per cent ownership interest in TC Turbines.

Capital spending[1]

The following table summarizes capital spending by segment.

year ended December 31 (millions of $)	2021	2020	2019
Canadian Natural Gas Pipelines	**2,737**	3,608	3,906
U.S. Natural Gas Pipelines	**2,820**	2,785	2,516
Mexico Natural Gas Pipelines	**129**	173	357
Liquids Pipelines	**571**	1,442	954
Power and Storage	**842**	834	1,019
Corporate	**35**	58	32
	7,134	8,900	8,784

1 Capital spending includes Capital expenditures, Capital projects in development and Contributions to equity investments. Refer to Note 4, Segmented information, of our 2021 Consolidated financial statements for the financial statement line items that comprise total capital spending.

Capital expenditures

Capital expenditures in 2021 were incurred primarily for the expansion of the NGTL System, ANR and Columbia Gas projects, as well as maintenance capital expenditures. Lower capital spending in 2021 compared to 2020 reflected reduced spending on Columbia Gas projects, the sale of a 65 per cent equity interest in and subsequent equity accounting for Coastal GasLink LP in second quarter 2020, along with the termination of the Keystone XL pipeline project following the January 20, 2021 revocation of the Presidential Permit, partially offset by higher capital spending on ANR.

Capital projects in development

Costs incurred during 2020 and 2019 on Capital projects in development were predominantly attributable to spending on Keystone XL. The decrease in development spending in 2020 compared to 2019 is due to project costs being reflected in Capital expenditures subsequent to our March 31, 2020 decision to proceed with construction.

Contributions to equity investments

Contributions to equity investments increased in 2021 compared to 2020 mainly due to higher investments in Bruce Power and Iroquois.

Contributions to equity investments increased in 2020 compared to 2019 mainly due to higher investment in Bruce Power and our investment in Coastal GasLink LP subsequent to its reclassification to an equity investment.

Contributions to equity investments in 2019 include our proportionate share of Sur de Texas debt financing.

Proceeds from sales of assets

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

In 2020, we completed the following portfolio management transactions. All cash proceeds amounts are prior to income tax and post-closing adjustments:
- the sale of our Ontario natural gas-fired power plant assets for net proceeds of approximately $2.8 billion
- the sale of a 65 per cent equity interest in Coastal GasLink LP for net proceeds of $656 million.

In addition to the proceeds from the above transactions, in 2020, we received $1.5 billion from the initial draw by Coastal GasLink LP on the project-level financing which preceded the equity sale.

In 2019, we completed the following portfolio management transactions. All cash proceeds amounts are prior to income tax and post-closing adjustments:
- the sale of certain Columbia Midstream assets for proceeds of approximately US$1.3 billion
- the sale of the Coolidge generating station for proceeds of US$448 million
- the sale of an 85 per cent equity interest in Northern Courier for proceeds of $144 million.

In addition to the proceeds from the above transactions, in 2019, we received a $1.0 billion distribution from the Northern Courier debt issuance which preceded the equity sale.

Acquisition

On November 13, 2020, we acquired the remaining 50 per cent ownership interest in TC Turbines for cash consideration of US$67 million.

Other distributions from equity investments

Other distributions from equity investments relate to our proportionate share of the Sur de Texas debt repayments in 2021 along with 2019 distributions received from Bruce Power and Northern Border financings undertaken to fund their respective capital programs and to also make distributions to their partners. In 2021, we received distributions of $73 million from Sur de Texas in relation to the repayment on our 60 per cent proportionate share of long-term debt financing to the joint venture. In 2019, we received distributions of $120 million from Bruce Power in connection with their issuance of senior notes in the capital markets, as well as $66 million from Northern Border originating from a draw on its revolving credit facility to manage capitalization levels.

Cash (used in)/provided by financing activities

year ended December 31 (millions of $)	**2021**	**2020**	**2019**
Notes payable issued/(repaid), net	**1,003**	(220)	1,656
Long-term debt issued, net of issue costs	**10,730**	5,770	3,024
Long-term debt repaid	**(7,758)**	(3,977)	(3,502)
Junior subordinated notes issued, net of issue costs	**495**	—	1,436
Loss on settlement of financial instruments	**(10)**	(130)	—
Redeemable non-controlling interest repurchased	**(633)**	—	—
Contributions from redeemable non-controlling interest	**—**	1,033	—
Dividends and distributions paid	**(3,548)**	(3,367)	(2,174)
Common shares issued, net of issue costs	**148**	91	253
Preferred shares redeemed	**(500)**	—	—
Acquisition of TC PipeLines, LP transaction costs	**(15)**	—	—
Net cash (used in)/provided by financing activities	**(88)**	(800)	693

Net cash used in financing activities decreased by $0.7 billion in 2021 compared to 2020 primarily due to higher net issuances of long-term debt and notes payable along with the 2021 issuance of junior subordinated notes, partially offset by contributions received in 2020 in support of Keystone XL construction in the form of a redeemable non-controlling interest as well as the 2021 subsequent repurchase of the redeemable non-controlling interest in addition to the preferred shares redemption.

Net cash provided by financing activities decreased by $1.5 billion in 2020 compared to 2019 primarily due to the net repayment of notes payable in 2020, the issuance of junior subordinated notes in 2019 and higher cash dividends and distributions paid in 2020 as DRP participation was no longer satisfied through the issuance of common shares from treasury at a discount. This was partially offset by higher issuances of long-term debt and contributions in support of Keystone XL construction in the form of a redeemable non-controlling interest.

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 2021:

(millions of Canadian $, unless otherwise noted) Company	Issue date	Type	Maturity date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	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 %
KEYSTONE XL SUBSIDIARIES[1]					
	Various	Project-Level Credit Facility	June 2021	US 849	Floating
COLUMBIA PIPELINE GROUP, INC.[2]					
	January 2021	Unsecured Term Loan	June 2022	US 4,040	Floating

1 On January 4, 2021, we 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.

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.

The net proceeds of the above TCPL debt issuances were used for general corporate purposes, to fund our capital program and to repay existing debt.

Long-term debt retired/repaid

The following table outlines significant long-term debt repaid in 2021:

(millions of Canadian $, unless otherwise noted) Company	Retirement/repayment date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	November 2021	Medium Term Notes	500	3.65 %
	January 2021	Debentures	US 400	9.875 %
COLUMBIA PIPELINE GROUP, INC.				
	December 2021	Unsecured Term Loan	US 4,040	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	9.625 %
KEYSTONE XL SUBSIDIARIES[1]				
	June 2021	Project-Level Credit Facility	US 849	Floating

1 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, and it was subsequently terminated, resulting in no cash impact to TC Energy.

On March 4, 2021, our subsidiary, TC PipeLines, LP, terminated our US$500 million Unsecured Loan Facility bearing interest at a floating rate on which no amount was outstanding.

Junior subordinated notes issued

In March 2021, TransCanada Trust (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 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.

For more information about long-term debt and junior subordinated notes issued and long-term debt repaid in 2021, 2020 and 2019, refer to the notes to our 2021 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 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. Commencing with the dividends declared October 31, 2019, common shares purchased under TC Energy's DRP are acquired on the open market at 100 per cent of the weighted average purchase price. From January 1, 2019 to October 31, 2019, common shares under the DRP were issued from treasury at a discount of two per cent to market prices over a specified period.

TC Energy Corporate ATM program

In December 2020, we established a new ATM program that allows us to issue common shares from treasury having an aggregate gross sales price of up to $1.0 billion, or the U.S. dollar equivalent, to the public from time to time, at our discretion, at the prevailing market price when sold through the TSX, the NYSE, or any other applicable existing trading market for TC Energy common shares in Canada or the U.S. While not a component of our base funding plan, the ATM program, which is effective for a 25-month period, provides additional financial flexibility in support of our consolidated credit metrics and capital program and may be activated if, and as, deemed appropriate. No common shares were issued under the program in 2021 or 2020.

Share information

as at February 9, 2022		
Common Shares	**issued and outstanding**	
	981 million	
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
Series 15	40 million	Series 16 preferred shares
Options to buy common shares	**outstanding**	**exercisable**
	8 million	4 million

On May 31, 2021, we redeemed all of the 20 million 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 as previously declared on May 6, 2021.

On March 3, 2021, we issued 37,955,093 TC Energy common shares to acquire all the outstanding common units of TC PipeLines, LP, not beneficially owned by TC Energy, valued at approximately $2.1 billion, net of transaction costs. Refer to the Corporate – Significant events section for additional information on the acquisition.

On February 1, 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.

For more information on preferred shares refer to the notes to our 2021 Consolidated financial statements.

Dividends

year ended December 31	2021	2020	2019
Dividends declared			
per common share	$3.48	$3.24	$3.00
per Series 1 preferred share	$0.86975	$0.86975	$0.8165
per Series 2 preferred share	$0.50997	$0.7099	$0.89872
per Series 3 preferred share	$0.4235	$0.48075	$0.538
per Series 4 preferred share	$0.34997	$0.54989	$0.73872
per Series 5 preferred share	$0.48725	$0.56575	$0.56575
per Series 6 preferred share	$0.41622	$0.52537	$0.7976
per Series 7 preferred share	$0.97575	$0.97575	$0.98181
per Series 9 preferred share	$0.9405	$0.9405	$1.032
per Series 11 preferred share	$0.83775	$0.92194	$0.95
per Series 13 preferred share	$0.34375	$1.375	$1.375
per Series 15 preferred share	$1.225	$1.225	$1.225

On February 14, 2022, we increased the quarterly dividend on our outstanding common shares by 3.4 per cent to $0.90 per common share for the quarter ending March 31, 2022 which equates to an annual dividend of $3.60 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, 2022, we had a total of $12.4 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 TCPL's Canadian dollar commercial paper program and for general corporate purposes	December 2026	3.0	0.8
TCPL / TCPL USA /Columbia / TransCanada American Investments Ltd.	Supports TCPL's and TCPL USA's U.S. dollar commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2022	US 4.5	US 1.7
TCPL / TCPL USA / Columbia / TransCanada American Investments Ltd.	For general corporate purposes of the borrowers, guaranteed by TCPL	December 2024	US 1.0	US 1.0
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	2.1 [2]	1.0 [2]
Mexico subsidiary	For Mexico general corporate purposes, guaranteed by TCPL	Demand	MXN 5.0 [2]	MXN 2.6 [2]

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

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, 2021					
(millions of $)	**Total**	**< 1 year**	**1 - 3 years**	**4 - 5 years**	**> 5 years**
Notes payable	5,166	5,166	—	—	—
Long-term debt and junior subordinated notes[1]	47,928	1,320	4,480	4,476	37,652
Operating leases[2]	554	73	136	129	216
Purchase obligations and other	4,625	2,211	773	432	1,209
	58,273	8,770	5,389	5,037	39,077

1 Excludes issuance costs.
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 were $5.2 billion at the end of 2021 compared to $4.2 billion at the end of 2020.

Long-term debt and junior subordinated notes

At December 31, 2021, we had $38.7 billion of long-term debt and $8.9 billion of junior subordinated notes outstanding compared to $36.9 billion of long-term debt and $8.5 billion of junior subordinated notes at December 31, 2020.

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 20 years.

Interest payments

At December 31, 2021, scheduled interest payments related to our long-term debt and junior subordinated notes were as follows:

at December 31, 2021					
(millions of $)	**Total**	**< 1 year**	**1 - 3 years**	**4 - 5 years**	**> 5 years**
Long-term debt	23,278	1,777	3,384	3,028	15,089
Junior subordinated notes	21,658	461	922	916	19,359
	44,936	2,238	4,306	3,944	34,448

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.

Payments due (by period)

at December 31, 2021 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Canadian Natural Gas Pipelines					
Transportation by others[1]	1,829	160	327	308	1,034
Capital spending[2]	1,472	1,432	37	3	—
U.S. Natural Gas Pipelines					
Transportation by others[1]	619	128	219	97	175
Capital spending[2]	130	124	6	—	—
Mexico Natural Gas Pipelines					
Capital spending[2]	102	31	71	—	—
Liquids Pipelines					
Capital spending[2]	57	56	1	—	—
Other	9	3	6	—	—
Power and Storage					
Capital spending[2]	65	48	16	1	—
Other[3]	50	10	21	19	—
Corporate					
Other	278	205	69	4	—
Capital spending[2]	14	14	—	—	—
	4,625	2,211	773	432	1,209

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.

Outlook

Our capital program is comprised of approximately $24 billion of secured projects, as well as our projects under development, which are subject to key corporate and regulatory approvals. The 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 sales
- project financing
- potential involvement of strategic or financial partners.

In addition, we may access additional funding options below, as deemed appropriate:

- common shares issued from treasury under our DRP
- common shares issued under our ATM program
- discrete common equity issuance.

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 guarantees have terms extending up to June 2022.

At December 31, 2021, our share of potential exposure under the Sur de Texas pipeline guarantees was estimated to be $93 million with a carrying amount of less than $1 million.

Bruce Power

We and our joint venture partner on Bruce Power, BPC Generation Infrastructure Trust, have each severally guaranteed certain contingent financial obligations of Bruce Power related to a lease agreement. The Bruce Power guarantee has a term to 2023.

At December 31, 2021, 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, 2021 to be approximately $80 million with a carrying amount of $4 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 2021, we made funding contributions of $105 million to our defined benefit pension plans, $8 million for other post-retirement benefit plans and $58 million for the savings plan and defined contribution plans. We also provided an additional $20 million letter of credit to the Canadian defined benefit plan for funding of solvency requirements.

Considering current market conditions and the reduction to the number of active plan members due to the VRP, we expect 2022 required funding levels to be lower than 2021 levels, although actuarial valuations for determining 2022 funding of our pension and other post-retirement benefit plans as at January 1, 2022 will be carried out in mid-2022. We currently expect 2022 funding contributions of approximately $76 million for the defined benefit pension plans, approximately $7 million for other post-retirement benefit plans and approximately $55 million for the savings plans and defined contribution pension plans. In addition, we expect to provide an additional estimated $20 million letter of credit to the Canadian defined benefit plan for solvency funding requirements.

The net benefit cost for our defined benefit and other post-retirement plans decreased to $108 million in 2021 from $114 million in 2020 primarily due to the impact of a pension curtailment and settlement related to the VRP.

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

ENTERPRISE RISK MANAGEMENT

Risk management 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 tolerance. We manage risk through a centralized enterprise risk management (ERM) program that identifies enterprise risks, including ESG-related risks, that could materially impact the achievement of our strategic objectives.

Our Board of Directors retains general oversight of all enterprise risks, as identified below, and specifically has direct oversight of reputation and relationships, regulatory uncertainty, capital allocation strategy and 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. The Board also participates in detailed presentations on each enterprise risks 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 ESG risk, 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, health, safety, sustainability and environmental risk, including climate change related risks
- the Audit Committee oversees management's role in managing financial risk, including market risk, counterparty credit risk and cyber security.

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. The following is a summary of enterprise-wide risks with potential to affect all of our operations. These are being continuously monitored.

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 or contracts or covered by 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, includes our corporate health, safety, sustainability, environment and asset integrity programs to prevent incidents and protect employees, contractors, members of the public, the environment and our assets. 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. We also have a comprehensive insurance program to mitigate a certain portion of our risks, but insurance does not cover all events in all circumstances.
Climate change		
As a leading energy infrastructure company in North America, our assets could be impacted by significant temperature or weather changes and our business may be impacted by market risks resulting from emerging decarbonization policies or shifts in energy consumption affecting long-term energy supply and demand trajectories.	Fluctuations in energy supply and demand, increasing commodity prices or volatility and output capability. Business interruption caused by physical changes to our environment which could result in a decrease in revenues and increase in operating costs, legal proceedings or regulatory actions, or other expenses, all of which could reduce our earnings.	In 2021, we established a dedicated energy transition team to assess relevant technologies and opportunities to support business resiliency irrespective of the pace or direction of energy transition. This team worked cross functionally to set our enterprise-wide goal of 30 per cent reduction of GHG emission intensity by 2030 which positions us to achieve net-zero emissions from our operations by 2050, using a 2019 baseline year. We evaluate the resilience of our asset portfolio over a range of potential energy supply and demand outcomes, also known as scenario analysis, as part of our strategic planning process. We monitor climate policy and related developments through our ERM program to ensure leadership has visibility to the broader perspective, and that treatments are applied in a holistic and consistent manner. Our engineering standards are also regularly reviewed to ensure assets continue to be designed and operated to withstand the potential impacts of climate change.
Cyber security		
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 cyber security risks and could be subject to cyber security events directed against our information technology. 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 for long periods of time.	A breach in the security of our information technology could expose our business to a risk of loss, misuse or interruption of critical information and functions. This could affect our operations, damage our assets, result in safety incidents, damage to the environment and/or result in reputational harm, competitive disadvantage, regulatory enforcement actions and potential litigation, which could have a material adverse effect on our operations, financial position and results of operations.	We have a comprehensive cyber security strategy which aligns with industry and recognized standards for cyber security. This strategy is regularly reviewed and updated, and the status of our cyber security program is reported to the Audit Committee on a quarterly basis. The program includes cyber security risk assessments, continuous monitoring of networks and other information sources for threats to the organization, comprehensive incident response plans/processes and a robust cyber security awareness program for employees and contractors. We have insurance which may cover losses from physical damage to our facilities as a result of a cyber security event, but insurance does not cover all events in all circumstances.

Risk and description	Impact	Monitoring and mitigation
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 and government agencies and environmental non-governmental organizations.	Inadequately managing stakeholder expectations and concerns, including those related to ESG, 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, responsibility, collaboration, integrity and innovation – 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. Our most recent Report on Sustainability includes details on our specific commitments related to safety, partnerships with Indigenous communities, focus on landowner relationships and our workplace inclusion and diversity.
Regulatory uncertainty		
Our ability to construct and operate energy infrastructure requires regulatory approvals and is dependent on evolving policies and regulations by government authorities. This includes changes in regulation that may affect our projects and operations.	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.	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 rightsholders and stakeholders in the development and operation of our assets. We identify emerging risks and signposts including customer, regulatory and government decisions as well as innovative technology development, and report on 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 of time and changes in investor and lender sentiment could affect our ability to access capital at a competitive cost, which could negatively impact our ability to deliver an attractive return on our investments or inhibit our growth.	We operate within our financial means and risk tolerances, maintain a diverse array of funding levers and also utilize portfolio management as an important 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 ESG-related updates. We also conduct research around the evolving ESG 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.	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 divest of non-strategic assets, effectively rotating capital while adhering to our risk preferences and focus on per share metrics. We conduct analyses to identify resilient supply sources 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 and adapt to changing market conditions.

Risk and description	Impact	Monitoring and mitigation
Execution and capital costs		
Investing in large infrastructure projects involves substantial capital commitments and associated execution risks 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.

Health, safety, sustainability and environment

The Board's HSSE Committee oversees operational risk, occupational and process safety, sustainability, security of personnel, environmental and climate change related risks and monitors 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, programs and procedures.

Our management system, TOMS, is modeled after international standards, including the International Organization for Standardization (ISO) standard for environmental management systems, ISO 14001, and the Occupational Health and Safety Assessment Series for occupational health and safety. TOMS also conforms to applicable industry standards and complies with applicable regulatory requirements. It covers the lifecycle of our assets and follows a continuous improvement cycle organized into four key areas:

- Plan – risk and regulatory assessment as well as objective and target setting, which includes establishing total recordable case rate targets while striving for zero incidents plus defining roles and responsibilities
- Do – development and implementation of programs, procedures and standards to manage operational risk
- Check – incident reporting, investigation, assurance activities, including internal and external audits and performance monitoring
- Act – non-conformance, non-compliance and opportunities for improvement are managed and assessed by management.

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

- overall HSSE corporate governance
- operational performance and preventive maintenance metrics
- asset integrity programs
- environment programs
- significant occupational safety, process safety and asset integrity incidents
- emergency preparedness, incident response and evaluation
- occupational and process safety performance metrics
- 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, that 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, Reconciliation Action Plan, ESG Data Sheet and GHG Emissions Reduction Plan
- our Occupational Health and Hygiene Program, which includes physical and mental health and psychological safety.

Health, safety and asset integrity
The safety of our employees, contractors and the public as well as the integrity of our pipelines, power and storage infrastructure, are a top priority. All assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are placed into service only after all necessary requirements, both regulatory and internal, have been satisfied.

In 2021, we spent $1.4 billion for pipeline integrity on the natural gas and liquids pipelines we operate, similar to 2020. Pipeline integrity spending will fluctuate based on the results of annual 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 various integrity programs for the power and storage assets we operate 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 Business interruption and Climate change risk discussions 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, 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. Our Occupational Health and Hygiene Program 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 well-being, health education and improved working conditions to sustain a productive workforce
- increase mental well-being awareness, provide various mental health supports and training to employees and leaders, measure the success of programs and improve psychological health and safety.

In response to the COVID-19 pandemic, with guidance from government and public health authorities, we have implemented enhanced COVID-19 health and safety protocols and procedures to protect our employees, contractors and other stakeholders.

Environmental risk, compliance and liabilities
TOMS provides requirements for our day-to-day work to protect employees, contractors, our workplace and assets, the communities in which we work and the environment. It conforms to external industry consensus standards and voluntary programs plus complies with applicable legislative requirements. Under TOMS, mandated programs set requirements to manage specific risk areas for TC Energy, including the Environment Program, which is a documented set of processes and procedures that identifies our requirements to proactively and systematically manage environmental hazards and risks throughout the lifecycle of our assets. As part of our Environment Program, 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. To conserve and protect the environment during construction, information gathered for an environmental impact assessment is used to develop project-specific environmental protection plans. Additionally, the Environment Program, which applies to all of our operations, includes practices and procedures to manage potential adverse environmental effects to these resources during the full lifecycle of our facilities.

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, that 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, that 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.

Through the implementation of our Environment Program, we 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, 2021, accruals related to these obligations totaled $30 million (2020 – $24 million), representing the estimated amount we will need to manage our currently known environmental liabilities. We believe we have considered all necessary contingencies and established appropriate reserves for environmental liabilities, however, a risk exists that unforeseen matters may arise requiring us to set aside additional amounts. We adjust reserves regularly to account for changes in liabilities.

Climate change and related regulation

We own assets and have business interests in a number of regions subject to GHG emissions regulations, including GHG emissions management and carbon pricing policies. In 2021, we incurred $59 million (2020 – $64 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 level aimed at reducing GHG emissions. We actively monitor and submit comments to regulators as these new and evolving initiatives are undertaken and policies implemented. We support transparent climate change policies that promote sustainable and economically responsible natural resource development and, in October 2021, we published a GHG Emissions Reduction Plan that includes GHG reduction targets in support of global climate goals. 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 across our footprint. Changes in regulations may result in higher operating costs, other expenses or capital expenditures to comply with possible new regulations.

Existing policies

Canadian jurisdictions

- 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 and measurements to quantify emission reductions. Power facilities are not affected by this regulation at the current time
- 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 provinces of Ontario, Manitoba, Saskatchewan and New Brunswick as those jurisdictions did not have a provincial plan in place for carbon pricing which met the criteria of the Government of Canada when the policy was developed. As a result, our assets across Canada are all subject to some type of carbon pricing
- 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 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, and the CleanBC Industry Fund which 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
- 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 storage 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 storage assets are recovered through market pricing and hedging activities
- 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. The 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. The Canadian Mainline and TQM natural gas pipeline facilities in Québec are also subject to this program and compliance instruments have been or will be purchased in order to comply with the requirements of this initiative
- On March 29, 2021, the Ontario and Federal governments reached an agreement whereby the Federal OBPS in Ontario will be replaced on January 1, 2022 by the Ontario Emissions Performance Standards program. Covered facilities are required to meet the Federal OBPS regulations for the 2020 and 2021 compliance periods. Federal OBPS and the Ontario Emissions Performance Standards that apply to our Canadian Mainline operations in the province and costs under this program will be recovered in tolls. At this time, we do not anticipate a material impact to the financial performance of our Ontario natural gas facilities as a result of the Ontario Emissions Performance Standards program.

U.S. jurisdictions

- *Federal:* On June 30, 2021, a joint Congressional resolution (CRA resolution) disapproving the 2020 policy amendment was signed into law. The CRA resolution reinstated the 2016 New Source Performance Standards on the transmission and storage segments. The impact to us from the reinstatement was minimal as we previously made the decision to continue to comply even though the 2020 policy amendments removed the transmission and storage segment as an applicable source category
- *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
- *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.

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 GHGs and compounds 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
- in 2018, 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 emission reductions from prevention and control activities. This regulation requires the PPCIEM, through which operational and technological practices are adopted, to determine a 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
- in 2019, 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 will function as a three-year pilot from 2020 to 2022 that allows 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

- the Government of Canada is developing the Clean Fuel Standard (CFS) to achieve reductions in GHG emissions. In December 2020, the Canadian Federal Government unveiled its plan aimed to exceed their previous 2030 GHG emissions reduction target of 30 per cent below 2005 levels to a new target of 32 to 40 per cent below 2005 levels with the ultimate goal of achieving net-zero emissions by 2050. As part of this plan, the Federal Government narrowed the CFS scope to include only liquid fuels, which will not directly impact TC Energy. This plan also increased carbon pricing levels and released a complementary hydrogen strategy. Carbon prices are scheduled to increase by $15/tonne every year after 2022 to $170/tonne in 2030. While the scope of the CFS is limited to liquid fuels, there will be opportunities to generate credits for the gaseous fuel stream to incentivize emission reduction opportunities. We will continue to engage with Canadian policy makers and monitor and assess the extent of the impacts as more information is made available
- On October 11, 2021, ECCC committed to developing a plan to reduce oil and gas sector methane emissions by at least 75 per cent below 2012 levels by 2030. We will assess the potential implications of any policy and regulatory updates associated with this announcement through 2022 as more information is made available.

U.S. jurisdictions

- *Federal:* In August 2020, the U.S. Senate passed the PHMSA reauthorization bill, the PIPES Act, which included methane regulations requiring, for example, pipeline owners/operators to implement methane LDAR programs, deploy advanced leak detection technology and incorporate LDAR surveys in inspection and maintenance plans. If the U.S. House of Representatives also supports the inclusion of these methane provisions, PHMSA will join the United States Environmental Protection Agency (USEPA) as another federal regulator of GHG emissions, indicating the nation's increasing desire to combat climate change. The expected impact to our assets is still being evaluated
- *Federal:* On November 2, 2021, the USEPA released proposed rulemaking to reduce methane and other harmful air pollutants from both new and existing sources in the oil and natural gas industry. The methane rule was posted to the federal register on November 15, 2021 with a public hearing scheduled on November 30, 2021 and the public comment period closing on January 14, 2022. An additional supplemental proposal was released on November 15,2021 which included supporting regulator text. The proposed rule for new or modified sources is expected to impact any new projects that begin in 2022 and beyond. The guidelines for existing emission sources have the potential to impact all of our existing facilities when fully implemented in the future
- *Washington:* The state has announced the beginning of the rulemaking process for its cap-and-trade program, which passed through legislature in 2021. Rulemaking will proceed through 2022 with the program launching in January of 2023. The state is continuing rulemaking on its Greenhouse Gas Assessment for Projects rule, which would require projects to provide an estimate of their potential GHG emissions using the environmental assessment methods described in the rule. Rule language will be proposed in early 2022 and the state will hold public comments and hearings before finalizing later in the year. This program and associated rules would apply to our assets and projects in the state. They have also begun the process to update the Washington Commercial Building Code, including language that would limit the use of natural gas in new construction. This process will continue into 2022
- *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
- *Oregon:* In March 2020, the Governor of Oregon issued an executive order to reduce and regulate GHGs by establishing annual reduction goals, developing a new carbon cap and reduce program and enhancing clean fuel standards by January 1, 2022. The state Department of Environmental Quality recommended a final draft of the rule to the state Environmental Quality Commission (EQC) for a vote at the EQC's December 2021 meeting. The EQC approved the program which still exempts our facilities and their emissions
- *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:* In August 2020, New York's Department of Environmental Conservation (NY DEC) released its proposed GHG reduction regulations, implementing the Climate Leadership and Community Protection Act, which directed the NY DEC to adopt GHG limits for all state emission sources. The proposed regulations require a reduction in GHGs equal to 60 per cent of the 1990 GHG emission levels by 2030 and to 15 per cent of the 1990 GHG emission levels by 2050. The proposed regulation does not include any compliance requirements and, as such, the impact to our assets cannot yet be measured.

Changes to environmental remediation regulations – U.S. Jurisdictions

- *Federal:* On October 22, 2021, the USEPA proposed a rule entitled, Alternate Polychlorinated Biphenyl (PCB) Extraction Methods and Amendments to PCB Cleanup and Disposal Regulations. The rule addresses a myriad of issues related to laboratory methodologies, performance-based disposal options for PCB remediation waste and during emergency situations, among other proposed changes. We are currently reviewing the proposed rule to determine its impact, if any, to our PCB Management activities but at this time do not believe that it will have a material impact on our business, financial condition or results of operations.

Financial risks

We are exposed to market risk and counterparty credit risk 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. Market risk and counterparty credit risk 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 market risk and counterparty credit 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 enter into contracts and engage in hedging activities as well as 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 supply of these commodities could negatively impact opportunities to expand our asset base and re-contract with our shippers and customers as their contractual agreements expire.

Climate change also presents a potential financial impact to commodity prices and volumes. Our exposure to climate-change risk and resulting policy changes is managed through our business model, which is based on a long-term, low-risk strategy whereby the majority of our earnings are underpinned by regulated cost-of-service arrangements and long-term contracts. In addition, scenario planning against several demand outlooks and monitoring of key signposts is also considered as part of our long-term corporate strategic planning process.

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.

Many of our financial instruments and contractual obligations with variable rate components reference U.S. dollar LIBOR, of which certain rate settings have ceased to be published at the end of 2021 with full cessation by mid-2023. We have completed necessary system changes to facilitate the adoption of the proposed standard market reference rates. We have also completed the analysis of contracts impacted by reference rate reform and contract modifications, if required, will take place prior to the full cessation date in mid-2023. These changes are not expected to have a material impact on our consolidated financial statements; however, we will continue to monitor any new developments up to the full cessation date.

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 can affect our comparable EBITDA and net income. Refer to the 2021 Financial highlights – Foreign exchange section for additional information.

A small portion of our Mexico Natural Gas Pipelines monetary assets and liabilities are peso-denominated, while the functional currency for our Mexico operations is 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 our net income. This exposure is managed using foreign exchange derivatives.

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, foreign exchange forwards 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
- loans receivable.

The sustained impact of the COVID-19 pandemic and related global energy demand and supply disruption continues to contribute to market uncertainty impacting a number of our customers. While the majority of our credit exposure is to large creditworthy entities, we have increased our monitoring and communication with those counterparties experiencing greater financial pressures.

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 supportable forecasts to determine any impairment, which is recognized in Plant operating costs and other. At December 31, 2021 and 2020, we had no significant credit losses, no significant credit risk concentrations and no significant amounts past due or impaired.

We have significant credit and performance exposure to financial institutions because they 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.

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 more information about our liquidity.

Legal proceedings

Legal proceedings, arbitrations and actions are part of doing business. While we cannot predict the final outcomes of proceedings and actions with certainty, management does not expect any current or potential legal proceeding or action to 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, 2021, 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, 2021, 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, 2021, the internal control over financial reporting was effective.

Our internal control over financial reporting as of December 31, 2021 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included in our 2021 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 2021 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

When we prepare financial statements that conform with GAAP, we are required to make estimates and assumptions that affect the timing and amounts we record for our assets, liabilities, revenues and expenses because these items may be affected by future events. We base the estimates and assumptions on the most current information available, using our best judgment. We also regularly assess the assets and liabilities themselves.

The following accounting estimates require us to make significant assumptions based on factors that are either subjective or highly uncertain when preparing our financial statements and changes in these assumptions could have a material impact on the financial statements. Our accounting policies disclose the critical accounting estimates we make when preparing our financial statements.

Impairment of long-lived assets and goodwill

We review long-lived assets, such as plant, property and equipment, equity investments, goodwill and capital projects in development, for impairment whenever events or changes in circumstances lead us to believe we might not be able to recover an asset's carrying value. Factors we consider in our assessment of the recoverability of long-lived assets include, but are not limited to, macroeconomic conditions, changes in the industries and markets in which we operate, our ability to renew contracts, and the financial performance and prospects of our assets. If the total of the undiscounted future cash flows that we estimate for an asset within Property, plant and equipment, or the estimated selling price of any long-lived asset is less than its carrying value, we consider its fair value to be less than its carrying value and record an impairment loss to recognize this. For goodwill, if the fair value of the reporting unit determined using discounted cash flows is less than its carrying value, including goodwill, we consider it to be impaired.

In 2021 we recorded a $2.8 billion pre-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 ($2.1 billion after tax).

In 2020 and 2019, no impairments were recorded.

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. In August 2019, we completed the sale of certain Columbia Midstream assets to a third party. As these assets constituted a business within the Columbia reporting unit, $595 million of Columbia's goodwill allocated to these assets was released and netted in the gain on sale.

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.

As part of the annual goodwill impairment assessment, we evaluated qualitative factors impacting the fair value of the reporting units, other than the Columbia reporting unit for which we elected to proceed directly to a quantitative impairment test. It was determined that it was more likely than not that the fair value of all reporting units exceeded their carrying amounts, including goodwill, and therefore, goodwill was not impaired.

Following the uncontested rate case settlement with shippers in 2021, we performed a quantitative annual goodwill impairment test for Columbia as at December 31, 2021. It was determined that the fair value of Columbia exceeded its carrying value, including goodwill, at December 31, 2021.

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 recovered or refunded through the tolls charged by us. As a result, these gains and losses are deferred as regulatory assets or regulatory liabilities 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 $)	**2021**	**2020**
Other current assets	**169**	235
Other long-term assets	**48**	41
Accounts payable and other	**(221)**	(72)
Other long-term liabilities	**(47)**	(59)
	(51)	145

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, 2021 (millions of $)	**Total fair value**	**< 1 year**	**1 - 3 years**	**4 - 5 years**	**> 5 years**
Derivative instruments held for trading					
Assets	173	159	8	6	—
Liabilities	(200)	(184)	(12)	(3)	(1)
Derivative instruments in hedging relationships					
Assets	44	10	29	5	—
Liabilities	(68)	(37)	(30)	(1)	—
	(51)	(52)	(5)	7	(1)

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 $)	2021	2020	2019
Derivative instruments held for trading[1]			
Amount of unrealized gains/(losses) in the year			
Commodities	**9**	(23)	(111)
Foreign exchange	**(203)**	126	245
Amount of realized gains/(losses) in the year			
Commodities	**287**	183	378
Foreign exchange	**240**	(33)	(70)
Derivative instruments in hedging relationships[2]			
Amount of realized (losses)/gains in the year			
Commodities	**(44)**	6	(6)
Interest rate	**(32)**	(16)	2

1 Realized and unrealized gains and 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 and losses on foreign exchange held-for-trading derivative instruments are included on a net basis in Interest income and other.

2 There were no gains and losses included in Net income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

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 26, Risk management and financial instruments, of our 2021 Consolidated financial statements.

RELATED PARTY TRANSACTIONS

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.

Sur de Texas

At December 31, 2021, the Loans receivable from affiliates on our Consolidated balance sheet of MXN$19.7 billion or $1.2 billion, represented our 60 per cent proportionate share of debt financing to the Sur de Texas joint venture. At December 31, 2020, this loan was recorded as Long-term loans receivable from affiliates on our Consolidated balance sheet and amounted to MXN$20.9 billion or $1.3 billion.

Our Consolidated statement of income reflects the related interest income and foreign exchange impact on this loan receivable which were fully offset upon consolidation with corresponding amounts included in our 60 per cent proportionate share of Sur de Texas equity earnings as follows:

year ended December 31 (millions of $)	2021	2020	2019	Affected line item in the Consolidated statement of income
Interest income[1]	**87**	110	147	Interest income and other
Interest expense[2]	**(87)**	(110)	(147)	Income from equity investments
Foreign exchange (losses)/gains[1]	**(41)**	(86)	53	Interest income and other
Foreign exchange gains/(losses)[1]	**41**	86	(53)	Income from equity investments

1 Included in our Corporate segment.

2 Included in our Mexico Natural Gas Pipelines segment.

Coastal GasLink LP

We hold a 35 per cent equity interest in Coastal GasLink LP and have been contracted to develop and operate the Coastal GasLink pipeline. 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 $500 million at December 31, 2021 with an outstanding balance of $1 million (December 31, 2020 – nil) reflected in Loans receivable from affiliates on our Consolidated balance sheet.

On December 6, 2021, we entered into a subordinated loan agreement with Coastal GasLink LP to provide interim temporary financing, if necessary, of up to $3.3 billion to fund incremental project costs as a bridge to a required increase in the project-level financing. Financing available to Coastal GasLink LP under this agreement is provided through a combination of interest-bearing facilities subject to floating market-based rates and non-interest-bearing facilities that are subject to a return to us under certain conditions at the time the final cost of the project is determined. At December 31, 2021, Long-term loans receivable from affiliates on our Consolidated balance sheet reflected $238 million in amounts outstanding under the subordinated loan agreement.

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 2021 Consolidated financial statements.

QUARTERLY RESULTS

Selected quarterly consolidated financial data

2021 (millions of $, except per share amounts)	Fourth	Third	Second	First
Revenues	**3,584**	**3,240**	**3,182**	**3,381**
Net income/(loss) attributable to common shares	**1,118**	**779**	**975**	**(1,057)**
Comparable earnings	**1,035**	**972**	**1,038**	**1,108**
Share statistics:				
Net income/(loss) per common share – basic	**$1.14**	**$0.80**	**$1.00**	**($1.11)**
Comparable earnings per common share	**$1.06**	**$0.99**	**$1.06**	**$1.16**
Dividends declared per common share	**$0.87**	**$0.87**	**$0.87**	**$0.87**

2020 (millions of $, except per share amounts)	Fourth	Third	Second	First
Revenues	3,297	3,195	3,089	3,418
Net income attributable to common shares	1,124	904	1,281	1,148
Comparable earnings	1,080	893	863	1,109
Share statistics:				
Net income per common share – basic	$1.20	$0.96	$1.36	$1.22
Comparable earnings per common share	$1.15	$0.95	$0.92	$1.18
Dividends declared per common share	$0.81	$0.81	$0.81	$0.81

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 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 generally remain relatively stable during any fiscal year. Over the long term, however, they fluctuate because of:

- regulatory decisions
- negotiated settlements with shippers
- newly constructed assets being placed in service
- acquisitions and divestitures
- developments outside of the normal course of operations.

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 Storage, 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
- 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 and non-GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period.

Comparable earnings exclude the unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to specific financial and commodity price risks. These derivatives generally provide effective economic hedges but do not meet the criteria for hedge accounting. As a result, the 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 part of our underlying operations. We also exclude the unrealized foreign exchange gains and losses on the loan receivable from affiliate as well as the corresponding proportionate share of Sur de Texas foreign exchange gains and losses, as these amounts do not accurately reflect the gains and losses that will be realized at settlement. These amounts offset within each reporting period, resulting in no impact on net income.

In fourth quarter 2021, comparable earnings also excluded:
- an incremental $60 million after-tax reduction to the Keystone XL asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, related to the termination of the Keystone XL pipeline project
- an after-tax gain of $19 million related to the sale of the remaining interest in Northern Courier
- preservation and storage costs for Keystone XL pipeline project assets of $10 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $7 million after-tax gain related to pension adjustments as part of the VRP
- an incremental $6 million income tax expense related to the sale of our Ontario natural gas-fired power plants sold in April 2020.

In third quarter 2021, comparable earnings also excluded:
- a $55 million after-tax expense with respect to transition payments incurred as part of the VRP
- preservation and storage costs for Keystone XL pipeline project assets of $11 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge.

In second quarter 2021, comparable earnings also excluded:
- preservation and storage costs for Keystone XL pipeline project assets of $16 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge and interest expense on the Keystone XL project-level credit facility prior to its termination
- a $13 million after-tax recovery of certain costs from the IESO associated with the Ontario natural gas-fired power plants sold in April 2020
- an incremental $2 million 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.

In first quarter 2021, comparable earnings also excluded:
- an after-tax asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, of $2.2 billion related to the formal suspension of the Keystone XL pipeline project following the January 20, 2021 revocation of the Presidential Permit.

In fourth quarter 2020, comparable earnings also excluded:

- an incremental after-tax loss of $81 million related to the sale of our Ontario natural gas-fired power plants
- an income tax valuation allowance release of $18 million related to certain prior years' U.S. income tax losses resulting from our reassessment of deferred tax assets that are more likely than not to be realized
- an additional $18 million income tax recovery related to state income taxes on the sale of certain Columbia Midstream assets in 2019.

In third quarter 2020, comparable earnings also excluded:

- an incremental after-tax loss of $45 million related to the sale of the Ontario natural gas-fired power plants
- a $6 million reduction in the after-tax gain related to the sale of a 65 per cent equity interest in Coastal GasLink LP.

In second quarter 2020, comparable earnings also excluded:

- an after-tax gain of $408 million related to the sale of a 65 per cent equity interest in Coastal GasLink LP
- an incremental after-tax loss of $80 million related to the sale of the Ontario natural gas-fired power plants.

In first quarter 2020, comparable earnings also excluded:

- an income tax valuation allowance release of $281 million following our reassessment of deferred tax assets that are deemed more likely than not to be realized
- an incremental after-tax loss of $77 million related to the Ontario natural gas-fired power plant assets held for sale.

FOURTH QUARTER 2021 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	**2021**	**2020**
Canadian Natural Gas Pipelines	**389**	350
U.S. Natural Gas Pipelines	**818**	730
Mexico Natural Gas Pipelines	**123**	137
Liquids Pipelines	**373**	300
Power and Storage	**191**	43
Corporate	**(6)**	(150)
Total segmented earnings	**1,888**	1,410
Interest expense	**(611)**	(530)
Allowance for funds used during construction	**72**	95
Interest income and other	**87**	373
Income before income taxes	**1,436**	1,348
Income tax expense	**(278)**	(116)
Net income	**1,158**	1,232
Net income attributable to non-controlling interests	**(8)**	(69)
Net income attributable to controlling interests	**1,150**	1,163
Preferred share dividends	**(32)**	(39)
Net income attributable to common shares	**1,118**	1,124
Net income per common share – basic	**$1.14**	$1.20

Net income attributable to common shares decreased by $6 million or $0.06 per common share for the three months ended December 31, 2021 compared to the same period in 2020. Net income per common share in fourth quarter 2021 reflects the impact of common shares issued for the acquisition of the remaining ownership interests in TC PipeLines, LP in first quarter 2021.

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

Fourth quarter 2021 results included:

- an incremental $60 million after-tax reduction to the Keystone XL 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 20, 2021 revocation of the Presidential Permit
- an after-tax gain of $19 million related to the sale of the remaining interest in Northern Courier
- preservation and storage costs for Keystone XL pipeline project assets of $10 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $7 million after-tax gain primarily related to pension adjustments incurred as part of the VRP
- an incremental $6 million income tax expense related to the sale of our Ontario natural gas-fired power plants sold in April 2020.

The Keystone XL pipeline project asset impairment charge does not reflect offsetting amounts with respect to the Government of Alberta's investment in Keystone XL nor their repayment of the project's guaranteed credit facility without recourse to TC Energy, both of which were accounted for within the Consolidated statement of equity in second quarter 2021 and served to reduce our net financial impact from the Keystone XL pipeline project termination.

Fourth quarter 2020 results included:

- an incremental after-tax loss of $81 million related to the Ontario natural-gas fired power plants sold in April 2020
- an income tax valuation allowance release of $18 million following our reassessment of deferred tax assets that were deemed more likely than not to be realized in 2020
- an additional $18 million income tax recovery related to state income taxes on the sale of certain Columbia Midstream assets.

Net income in all periods included unrealized gains and losses from changes in risk management activities which we exclude, along with the above noted items, to arrive at comparable earnings. A reconciliation of Net income attributable to common shares to comparable earnings is shown in the following table.

Reconciliation of net income to comparable earnings

three months ended December 31 (millions of $, except per share amounts)	2021	2020
Net income attributable to common shares	**1,118**	1,124
Specific items (net of tax):		
Keystone XL asset impairment charge and other	**(60)**	—
Gain on partial sale of Northern Courier	**(19)**	—
Voluntary Retirement Program	**(7)**	—
Keystone XL preservation and other	**10**	—
Loss on sale of Ontario natural gas-fired power plants	**6**	81
Income tax valuation allowance releases	**—**	(18)
Gain on sale of Columbia Midstream assets	—	(18)
Risk management activities[1]	**(13)**	(89)
Comparable earnings	**1,035**	1,080
Net income per common share	**$1.14**	$1.20
Specific items (net of tax):		
Keystone XL asset impairment charge and other	**(0.06)**	—
Gain on partial sale of Northern Courier	**(0.02)**	—
Voluntary Retirement Program	**(0.01)**	—
Keystone XL preservation and other	**0.01**	—
Loss on sale of Ontario natural gas-fired power plants	**0.01**	0.08
Income tax valuation allowance releases	**—**	(0.02)
Gain on sale of Columbia Midstream assets	—	(0.02)
Risk management activities	**(0.01)**	(0.09)
Comparable earnings per common share	**$1.06**	$1.15

1

three months ended December 31 (millions of $)	2021	2020
U.S. Natural Gas Pipelines	**7**	—
Liquids Pipelines	**(5)**	(25)
Canadian Power	**4**	(1)
Natural Gas Storage	**30**	(5)
Foreign exchange	**(20)**	150
Income taxes attributable to risk management activities	**(3)**	(30)
Total unrealized gains from risk management activities	**13**	89

Comparable EBITDA to comparable earnings

Comparable EBITDA represents segmented earnings adjusted for the specific items described above and excludes non-cash charges for depreciation and amortization.

three months ended December 31 (millions of $, except per share amounts)	2021	2020
Comparable EBITDA		
Canadian Natural Gas Pipelines	**674**	682
U.S. Natural Gas Pipelines	**1,032**	919
Mexico Natural Gas Pipelines	**151**	166
Liquids Pipelines	**380**	408
Power and Storage	**177**	161
Corporate	**(10)**	(13)
Comparable EBITDA	**2,404**	2,323
Depreciation and amortization	**(634)**	(652)
Interest expense	**(611)**	(530)
Allowance for funds used during construction	**72**	95
Interest income and other included in comparable earnings	**103**	86
Income tax expense included in comparable earnings	**(259)**	(134)
Net income attributable to non-controlling interests	**(8)**	(69)
Preferred share dividends	**(32)**	(39)
Comparable earnings	**1,035**	1,080
Comparable earnings per common share	**$1.06**	$1.15

Comparable EBITDA – 2021 versus 2020

Comparable EBITDA increased by $81 million for the three months ended December 31, 2021 compared to the same period in 2020 primarily due to the net effect of the following:

- increased earnings in U.S. Natural Gas Pipelines primarily from higher Columbia Gas transportation rates effective February 1, 2021 as a result of the subsequently uncontested rate case settlement, lower operating costs across a number of pipelines and improved earnings from our mineral rights business
- higher Power and Storage comparable EBITDA resulting from increased Canadian Power earnings mainly due to contributions from trading activities and higher realized margins, as well as increased earnings from Bruce Power due to higher volumes resulting from fewer outage days
- decreased earnings from Liquids Pipelines attributable to lower volumes on the U.S. Gulf Coast section of the Keystone Pipeline System, partially offset by increased contributions from liquids marketing activities reflecting higher margins and volumes
- lower comparable EBITDA from Canadian Natural Gas Pipelines due to the net effect of lower flow-through depreciation and financial charges, partially offset by higher incentive earnings and the elimination of the TC Energy contribution on the Canadian Mainline, offset in part by higher flow-through income taxes as well as increased rate-base earnings on the NGTL System
- foreign exchange impact of a weaker U.S. dollar on the Canadian dollar equivalent segmented earnings in our U.S. dollar-denominated operations. As detailed below, U.S. dollar-denominated comparable EBITDA increased by US$92 million to US$1.2 billion compared to US$1.1 billion in 2020; however, this was translated at a rate of 1.26 in 2021 versus 1.30 in 2020. Refer to the Foreign exchange discussion below for additional information.

While the weakening of the U.S. dollar in fourth quarter 2021 compared to the same period in 2020 had a considerable negative impact on 2021 comparable EBITDA for the three months ended December 31, 2021, the corresponding impact on comparable earnings was not significant due to offsetting natural and economic hedges. Refer to the Foreign exchange discussion below for additional information.

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

Comparable earnings – 2021 versus 2020

Comparable earnings decreased by $45 million or $0.09 per common share for the three months ended December 31, 2021 compared to the same period in 2020 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher Income tax expense mainly due to the impact of lower foreign tax rate differentials, Mexico inflationary adjustments, as well as increased flow-through income taxes on Canadian rate-regulated pipelines
- higher Interest expense primarily due to lower capitalized interest as a result of its cessation for the Keystone XL pipeline project following the revocation of the Presidential Permit on January 20, 2021, partially offset by the foreign exchange impact from a weaker U.S. dollar on translation of U.S. dollar-denominated interest
- lower AFUDC, predominantly due to suspension of recording AFUDC on the Villa de Reyes project effective January 1, 2021 resulting from ongoing delays, partially offset by NGTL System expansion projects under construction
- lower Non-controlling interests following the March 3, 2021 acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy
- decreased Depreciation and amortization in our Canadian Natural Gas Pipelines due to one section of the Canadian Mainline being fully depreciated in 2021, partially offset by new projects in U.S. Gas Natural Gas Pipelines placed in service and certain fourth quarter 2021 adjustments related to the Columbia Gas uncontested rate case settlement
- higher Interest income and other mainly attributable to higher realized gains in 2021 compared to 2020 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Foreign exchange

Despite the decrease in the average exchange rate for the three months ended December 31, 2021 compared to 2020, the net impact of U.S. dollar movements on comparable earnings over this period, 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. 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$)	2021	2020
Comparable EBITDA		
U.S. Natural Gas Pipelines	**819**	706
Mexico Natural Gas Pipelines[1]	**140**	146
U.S. Liquids Pipelines	**216**	231
	1,175	1,083
Depreciation and amortization	**(245)**	(216)
Interest on long-term debt and junior subordinated notes	**(314)**	(315)
Capitalized interest	**—**	42
Allowance for funds used during construction	**28**	56
Non-controlling interests and other	**(9)**	(70)
	635	580
Average exchange rate - U.S. to Canadian dollars	**1.26**	1.30

1 Excludes interest expense on our inter-affiliate loan with Sur de Texas which is fully offset in Interest income and other.

Highlights by business segment

Canadian Natural Gas Pipelines

Canadian Natural Gas Pipelines segmented earnings increased by $39 million for the three months ended December 31, 2021 compared to the same period in 2020.

Net income for the NGTL System increased by $18 million for the three months ended December 31, 2021 compared to the same period in 2020 mainly due to a higher average investment base resulting from continued system expansions. Effective January 1, 2020, the NGTL System is operating under the 2020-2024 Revenue Requirement Settlement which includes an 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 $15 million for the three months ended December 31, 2021 compared to the same period in 2020 mainly as a result of higher incentive earnings and the elimination of a $20 million after-tax annual TC Energy contribution included in the previous settlement. Effective January 1, 2021, 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. In 2020, the Canadian Mainline operated under the terms of the 2015-2030 Tolls Application approved in 2014. The terms of the previous settlement included an ROE of 10.1 per cent on deemed common equity of 40 per cent, an incentive mechanism with both upside and downside risk and a $20 million after-tax annual TC Energy contribution to reduce the revenue requirement.

Comparable EBITDA for Canadian Natural Gas Pipelines decreased by $8 million for the three months ended December 31, 2021 compared to the same period in 2020 primarily due to the net effect of:

- lower flow-through depreciation and financial charges, partially offset by higher incentive earnings, the elimination of the TC Energy contribution and higher flow-through income taxes on the Canadian Mainline
- higher flow-through depreciation and income taxes as well as increased rate-base earnings on the NGTL System.

Depreciation and amortization decreased by $47 million for the three months ended December 31, 2021 compared to the same period in 2020 mainly due to one section of the Canadian Mainline being fully depreciated in 2021, partially offset by higher depreciation on the NGTL System from facilities that were placed in service.

U.S. Natural Gas Pipelines

U.S. Natural Gas Pipelines segmented earnings increased by $88 million for the three months ended December 31, 2021 compared to the same period in 2020 and included unrealized gains from changes in the fair value of derivatives related to our U.S. natural gas marketing business in 2021 which have been excluded from our calculation of comparable EBIT. A weaker U.S. dollar in 2021 had a negative impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2020.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$113 million for the three months ended December 31, 2021 compared to the same period in 2020 and was primarily due to the net effect of:

- a net increase in comparable EBITDA from Columbia Gas as a result of the higher transportation rates effective February 1, 2021, pursuant to the Columbia Gas uncontested rate case settlement. Refer to U.S. Natural Gas Pipelines – Significant events for additional information
- increased earnings from lower operating costs across a number of pipelines and the contribution from growth projects placed in service primarily on Columbia Gas and ANR
- increased earnings from our mineral rights business due to higher commodity prices.

Depreciation and amortization increased by US$30 million for the three months ended December 31, 2021 compared to the same period in 2020 mainly due to new projects placed in service and certain fourth quarter 2021 adjustments related to the Columbia Gas uncontested rate case settlement.

Mexico Natural Gas Pipelines

Mexico Natural Gas Pipelines comparable EBIT and segmented earnings decreased by $14 million for the three months ended December 31, 2021, compared to the same period in 2020. A weaker U.S. dollar in fourth quarter 2021 had a negative impact on the Canadian dollar equivalent segmented earnings compared to the same period in 2020.

Comparable EBITDA for Mexico Natural Gas Pipelines decreased by US$6 million for the three months ended December 31, 2021 compared to the same period in 2020 as a result of lower equity income from Sur de Texas.

Depreciation and amortization for the three months ended December 31, 2021 was consistent with the same period in 2020.

Liquids Pipelines

Liquids Pipelines segmented earnings increased by $73 million for the three months ended December 31, 2021 compared to the same period in 2020 and included the following specific items which have been excluded from our calculation of comparable EBIT:

- pre-tax asset impairment charge reduction of $79 million for the three months ended December 31, 2021, associated with the termination of the Keystone XL pipeline and related projects following the January 20, 2021 revocation of the Presidential Permit
- pre-tax preservation and storage costs for Keystone XL pipeline project assets of $14 million for the three months ended December 31, 2021, which could not be accrued as part of the Keystone XL asset impairment charge
- pre-tax gain of $13 million related to the sale of the remaining 15 per cent interest in Northern Courier in fourth quarter 2021
- unrealized gains and losses from changes in the fair value of derivatives related to our liquids marketing business.

A weaker U.S. dollar in 2021 had a negative impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2020.

Comparable EBITDA for Liquids Pipelines decreased by $28 million for the three months ended December 31, 2021 compared to the same period in 2020 and was primarily due to the net effect of:

- lower volumes on the U.S. Gulf Coast section of the Keystone Pipeline System
- increased contributions from liquids marketing activities due to higher margins and volumes.

Depreciation and amortization decreased by $3 million for the three months ended December 31, 2021 compared to the same period in 2020 primarily as a result of a weaker U.S. dollar.

Power and Storage

Power and Storage segmented earnings increased by $148 million for the three months ended December 31, 2021 compared to the same period in 2020 and included the following specific items which have been excluded from comparable EBIT:

- a pre-tax loss of $93 million for the three months ended December 31, 2020 related to the sale of our Ontario natural gas-fired power plants
- unrealized gains and losses from changes in the fair value of derivatives used to manage our exposure to commodity price risk.

Comparable EBITDA for Power and Storage increased by $16 million for the three months ended December 31, 2021 compared to the same period in 2020 primarily due to the net effect of:

- increased Canadian Power earnings primarily due to contributions from trading activities and higher realized margins
- increased contributions from Bruce Power mainly due to higher volumes resulting from lower outage days, partially offset by increased operating costs
- decreased Natural Gas Storage and other earnings as a result of increased business development activities across the segment and lower realized Alberta natural gas storage spreads.

Depreciation and amortization for the three months ended December 31, 2021 was consistent with the same period in 2020.

Corporate

Corporate segmented losses decreased by $144 million for the three months ended December 31, 2021 compared to the same period in 2020. Corporate segmented losses included an $8 million gain primarily due to a pension settlement and curtailment following the VRP offered in mid-2021. In addition, segmented losses included foreign exchange losses and gains on our proportionate share of peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners. These foreign exchange losses and gains are recorded in Income from equity investments in the Corporate segment and have been excluded from our calculation of comparable EBITDA and EBIT as they are fully offset by corresponding foreign exchange gains and losses on the inter-affiliate loan receivable included in Interest income and other.

Comparable EBITDA and EBIT for Corporate for the three months ended December 31, 2021 was largely consistent with the same period in 2020.

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

ATM	An at-the-market program allowing us to issue common shares from treasury at the prevailing market price
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
ESG	Environmental, social and governance
Empress	A major delivery/receipt point for natural gas near the Alberta/Saskatchewan border
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it
GHG	Greenhouse gas
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
MOU	Memorandum of understanding
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
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
GAAP	U.S. generally accepted accounting principles
LIBOR	London Interbank Offered Rate
RRA	Rate-regulated accounting
ROE	Return on common equity

Government and regulatory bodies terms

CER	Canada Energy Regulator (formerly the National Energy Board (Canada))
CFE	Comisión Federal de Electricidad (Mexico)
CRE	Comisión Reguladora de Energia, 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
OPEC+	Organization of the Petroleum Exporting Countries plus certain other oil-exporting nations
OPG	Ontario Power Generation
PHMSA	Pipeline and Hazardous Materials Safety Administration
SEC	U.S. Securities and Exchange Commission
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 2021 to that in 2020, and highlights significant changes between 2020 and 2019. 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, 2021, 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 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 five 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 14, 2022

Report of Independent Registered Public Accounting Firm

To the Shareholders of 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, 2021 and 2020, 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, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2021, 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, 2021, 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 14, 2022 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 judgment. 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.

Qualitative goodwill impairment indicators

As discussed in Note 13 to the consolidated financial statements, the goodwill balance as of December 31, 2021 was $12,582 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. Other than the Columbia Pipeline Group, Inc. (Columbia) reporting unit where the Company has elected to proceed directly to a quantitative goodwill impairment test, the Company performed qualitative assessments to determine whether events or changes in circumstances indicate that goodwill might be impaired. These qualitative assessments were performed as of December 31, 2021.

We identified the evaluation of qualitative goodwill impairment indicators, or qualitative factors, 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 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 quantitative goodwill impairment tests performed in previous periods. In addition, we involved a valuation professional with specialized skills and knowledge, who assisted in:

- evaluating the Company's determination of 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.

Valuation of goodwill for the Columbia reporting unit

As discussed in Note 13 to the consolidated financial statements, the goodwill balance as of December 31, 2021 was $12,582 million, of which $9,303 million related to the Columbia reporting unit. 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 has the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. In respect of the Columbia reporting unit, the Company elected to proceed directly to the quantitative goodwill impairment test following an uncontested rate case settlement with shippers in 2021. 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 (key assumptions).

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 key assumptions. We compared the Company's historical revenue and capital expenditure projections to actual results to assess the Company's ability to accurately forecast. We evaluated the Company's revenue and capital expenditure projections by comparing them to the actual results and the outcomes of the uncontested rate case settlement with shippers in 2021. We also compared the Company's revenue and capital expenditure projections to assumptions used in industry publications related to North American and global energy consumption and natural gas production forecasts. 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.

KPMG LLP

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

Calgary, Canada
February 14, 2022

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of 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, 2021, 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, 2021, 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, 2021 and 2020, 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, 2021, and the related notes (collectively, the consolidated financial statements), and our report dated February 14, 2022 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting included in the Company's Management's Discussion and Analysis. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 14, 2022

Consolidated statement of income

year ended December 31 (millions of Canadian $, except per share amounts)	2021	2020	2019
Revenues (Note 5)			
Canadian Natural Gas Pipelines	**4,519**	4,469	4,010
U.S. Natural Gas Pipelines	**5,233**	5,031	4,978
Mexico Natural Gas Pipelines	**605**	716	603
Liquids Pipelines	**2,306**	2,371	2,879
Power and Storage	**724**	412	785
	13,387	12,999	13,255
Income from Equity Investments (Note 10)	**898**	1,019	920
Operating and Other Expenses			
Plant operating costs and other	**4,098**	3,878	3,913
Commodity purchases resold	**87**	—	365
Property taxes	**774**	727	727
Depreciation and amortization	**2,522**	2,590	2,464
Asset impairment charge and other (Note 6)	**2,775**	—	—
	10,256	7,195	7,469
Net Gain/(Loss) on Assets Sold/Held for Sale (Note 28)	**30**	(50)	(121)
Financial Charges			
Interest expense (Note 19)	**2,360**	2,228	2,333
Allowance for funds used during construction	**(267)**	(349)	(475)
Interest income and other	**(200)**	(213)	(460)
	1,893	1,666	1,398
Income before Income Taxes	**2,166**	5,107	5,187
Income Tax Expense (Note 18)			
Current	**305**	252	699
Deferred	**(185)**	(58)	55
	120	194	754
Net Income	**2,046**	4,913	4,433
Net income attributable to non-controlling interests (Note 21)	**91**	297	293
Net Income Attributable to Controlling Interests	**1,955**	4,616	4,140
Preferred share dividends	**140**	159	164
Net Income Attributable to Common Shares	**1,815**	4,457	3,976
Net Income per Common Share (Note 22)			
Basic	**$1.87**	$4.74	$4.28
Diluted	**$1.86**	$4.74	$4.27
Dividends Declared per Common Share	**$3.48**	$3.24	$3.00
Weighted Average Number of Common Shares (millions) (Note 22)			
Basic	**973**	940	929
Diluted	**974**	940	931

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 $)	2021	2020	2019
Net Income	**2,046**	4,913	4,433
Other Comprehensive Income/(Loss), Net of Income Taxes			
Foreign currency translation gains and losses on net investment in foreign operations	**(108)**	(609)	(944)
Reclassification to net income of foreign currency translation gains on disposal of foreign operations	**—**	—	(13)
Change in fair value of net investment hedges	**(2)**	36	35
Change in fair value of cash flow hedges	**(10)**	(583)	(62)
Reclassification to net income of gains and losses on cash flow hedges	**55**	489	14
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**158**	12	(10)
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	**14**	17	10
Other comprehensive income/(loss) on equity investments	**535**	(280)	(82)
Other comprehensive income/(loss) (Note 24)	**642**	(918)	(1,052)
Comprehensive Income	**2,688**	3,995	3,381
Comprehensive income attributable to non-controlling interests	**81**	259	194
Comprehensive Income Attributable to Controlling Interests	**2,607**	3,736	3,187
Preferred share dividends	**140**	159	164
Comprehensive Income Attributable to Common Shares	**2,467**	3,577	3,023

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 $)	2021	2020	2019
Cash Generated from Operations			
Net income	**2,046**	4,913	4,433
Depreciation and amortization	**2,522**	2,590	2,464
Asset impairment charge and other (Note 6)	**2,775**	—	—
Deferred income taxes (Note 18)	**(185)**	(58)	55
Income from equity investments (Note 10)	**(898)**	(1,019)	(920)
Distributions received from operating activities of equity investments (Note 10)	**975**	1,123	1,213
Employee post-retirement benefits funding, net of expense (Note 25)	**(5)**	(19)	(45)
Net (gain)/loss on assets sold/held for sale (Note 28)	**(30)**	50	121
Equity allowance for funds used during construction	**(191)**	(235)	(299)
Unrealized losses/(gains) on financial instruments	**194**	(103)	(134)
Foreign exchange losses/(gains) on loan receivable from affiliate (Note 11)	**41**	86	(53)
Other	**(67)**	57	(46)
(Increase)/decrease in operating working capital (Note 27)	**(287)**	(327)	293
Net cash provided by operations	**6,890**	7,058	7,082
Investing Activities			
Capital expenditures (Note 4)	**(5,924)**	(8,013)	(7,475)
Capital projects in development (Note 4)	**—**	(122)	(707)
Contributions to equity investments (Notes 4 and 10)	**(1,210)**	(765)	(602)
Proceeds from sales of assets, net of transaction costs	**35**	3,407	2,398
Loan to affiliate (Note 11)	**(239)**	—	—
Acquisition	**—**	(88)	—
Other distributions from equity investments (Note 10)	**73**	—	186
Payment for unredeemed shares of Columbia Pipeline Group, Inc. (Note 28)	**—**	—	(373)
Deferred amounts and other	**(447)**	(471)	(299)
Net cash used in investing activities	**(7,712)**	(6,052)	(6,872)
Financing Activities			
Notes payable issued/(repaid), net	**1,003**	(220)	1,656
Long-term debt issued, net of issue costs	**10,730**	5,770	3,024
Long-term debt repaid	**(7,758)**	(3,977)	(3,502)
Junior subordinated notes issued, net of issue costs	**495**	—	1,436
Loss on settlement of financial instruments (Note 26)	**(10)**	(130)	—
Redeemable non-controlling interest repurchased (Note 6)	**(633)**	—	—
Contributions from redeemable non-controlling interest (Note 6)	**—**	1,033	—
Dividends on common shares	**(3,317)**	(2,987)	(1,798)
Dividends on preferred shares	**(141)**	(159)	(160)
Distributions to non-controlling interests	**(74)**	(221)	(216)
Distributions on Class C Interests (Note 6)	**(16)**	—	—
Common shares issued, net of issue costs	**148**	91	253
Preferred shares redeemed (Note 23)	**(500)**	—	—
Acquisition of TC PipeLines, LP transaction costs (Note 21)	**(15)**	—	—
Net cash (used in)/provided by financing activities	**(88)**	(800)	693
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**53**	(19)	(6)
(Decrease)/Increase in Cash and Cash Equivalents	**(857)**	187	897
Cash and Cash Equivalents			
Beginning of year	**1,530**	1,343	446
Cash and Cash Equivalents			
End of year	**673**	1,530	1,343

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated balance sheet

at December 31 (millions of Canadian $)		2021	2020
ASSETS			
Current Assets			
Cash and cash equivalents		**673**	1,530
Accounts receivable		**3,092**	2,162
Loans receivable from affiliates (Note 11)		**1,217**	—
Inventories		**724**	629
Other current assets (Note 7)		**1,717**	880
		7,423	5,201
Plant, Property and Equipment (Note 8)		**70,182**	69,775
Equity Investments (Note 10)		**8,441**	6,677
Long-Term Loans Receivable from Affiliates (Note 11)		**238**	1,338
Restricted Investments		**2,182**	1,898
Regulatory Assets (Note 12)		**1,767**	1,753
Goodwill (Note 13)		**12,582**	12,679
Other Long-Term Assets (Note 14)		**1,403**	979
		104,218	100,300
LIABILITIES			
Current Liabilities			
Notes payable (Note 15)		**5,166**	4,176
Accounts payable and other (Note 16)		**5,099**	3,816
Dividends payable		**879**	795
Accrued interest		**577**	595
Redeemable non-controlling interest (Note 6)		**—**	633
Current portion of long-term debt (Note 19)		**1,320**	1,972
		13,041	11,987
Regulatory Liabilities (Note 12)		**4,300**	4,148
Other Long-Term Liabilities (Note 17)		**1,059**	1,475
Deferred Income Tax Liabilities (Note 18)		**6,142**	5,806
Long-Term Debt (Note 19)		**37,341**	34,913
Junior Subordinated Notes (Note 20)		**8,939**	8,498
		70,822	66,827
Redeemable Non-Controlling Interest (Note 6)		**—**	393
EQUITY			
Common shares, no par value (Note 22)		**26,716**	24,488
Issued and outstanding:	December 31, 2021 – 981 million shares		
	December 31, 2020 – 940 million shares		
Preferred shares (Note 23)		**3,487**	3,980
Additional paid-in capital		**729**	2
Retained earnings		**3,773**	5,367
Accumulated other comprehensive loss (Note 24)		**(1,434)**	(2,439)
Controlling Interests		**33,271**	31,398
Non-controlling interests (Note 21)		**125**	1,682
		33,396	33,080
		104,218	100,300

Commitments, Contingencies and Guarantees (Note 29)
Variable Interest Entities (Note 30)

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 $)	2021	2020	2019
Common Shares (Note 22)			
Balance at beginning of year	**24,488**	24,387	23,174
Shares issued:			
Acquisition of TC PipeLines, LP, net of transaction costs (Note 21)	**2,063**	—	—
Exercise of stock options	**165**	101	282
Dividend reinvestment and share purchase plan	**—**	—	931
Balance at end of year	**26,716**	24,488	24,387
Preferred Shares (Note 23)			
Balance at beginning of year	**3,980**	3,980	3,980
Redemption of shares	**(493)**	—	—
Balance at end of year	**3,487**	3,980	3,980
Additional Paid-In Capital			
Balance at beginning of year	**2**	—	17
Keystone XL project-level credit facility retirement and issuance of Class C Interests (Note 6)	**737**	—	—
Acquisition of TC PipeLines, LP (Note 21)	**(398)**	—	—
Repurchase of redeemable non-controlling interest (Note 6)	**394**	—	—
Issuance of stock options, net of exercises	**(6)**	2	(17)
Balance at end of year	**729**	2	—
Retained Earnings			
Balance at beginning of year	**5,367**	3,955	2,773
Net income attributable to controlling interests	**1,955**	4,616	4,140
Common share dividends	**(3,409)**	(3,045)	(2,794)
Preferred share dividends	**(133)**	(159)	(164)
Redemption of preferred shares	**(7)**	—	—
Balance at end of year	**3,773**	5,367	3,955
Accumulated Other Comprehensive Loss (Note 24)			
Balance at beginning of year	**(2,439)**	(1,559)	(606)
Other comprehensive income/(loss) attributable to controlling interests	**652**	(880)	(953)
Acquisition of TC PipeLines, LP (Note 21)	**353**	—	—
Balance at end of year	**(1,434)**	(2,439)	(1,559)
Equity Attributable to Controlling Interests	**33,271**	31,398	30,763
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,682**	1,634	1,655
Net income attributable to non-controlling interests	**90**	307	293
Other comprehensive loss attributable to non-controlling interests	**(10)**	(38)	(99)
Distributions declared to non-controlling interests	**(74)**	(221)	(215)
Acquisition of TC PipeLines, LP (Note 21)	**(1,563)**	—	—
Balance at end of year	**125**	1,682	1,634
Total Equity	**33,396**	33,080	32,397

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Notes to consolidated financial statements

1. DESCRIPTION OF TC ENERGY'S BUSINESS

TC Energy Corporation (TC Energy or the Company) is a leading North American energy infrastructure company which operates in five business segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines and Power and Storage. 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 in 40,580 km (25,216 miles) of regulated natural gas pipelines currently in operation.

U.S. Natural Gas Pipelines

The U.S. Natural Gas Pipelines segment primarily consists of the Company's investments in 50,211 km (31,199 miles) of regulated natural gas pipelines, 535 Bcf of regulated natural gas storage facilities and other assets currently in operation.

Mexico Natural Gas Pipelines

The Mexico Natural Gas Pipelines segment primarily consists of the Company's investments in 2,503 km (1,554 miles) of regulated natural gas pipelines currently in operation.

Liquids Pipelines

The Liquids Pipelines segment primarily consists of the Company's investments in 4,856 km (3,019 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 Storage

The Power and Storage segment primarily consists of the Company's investments in seven power generation facilities and 118 Bcf of non-regulated natural gas storage facilities. These assets are located in Alberta, Ontario, Québec and New Brunswick.

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, although certain non-controlling interests with redemption features are presented in mezzanine equity. 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 reporting units that contain goodwill (Notes 13 and 28)
- fair value of assets and liabilities acquired in a business combination (Note 28).

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 (Note 6)
- recoverability and depreciation rates of plant, property and equipment (Note 8)
- determining whether a contract contains a lease (Note 9)
- fair value of equity investments (Note 10)
- carrying value of regulatory assets and liabilities (Note 12)
- carrying value of asset retirement obligations (Note 17)
- provisions for income taxes, including valuation allowances and releases (Note 18)
- assumptions used to measure retirement and other post-retirement benefit obligations (Note 25)
- fair value of financial instruments (Note 26)
- provisions for commitments, contingencies and guarantees (Note 29).

TC Energy continues to assess the impact of climate change on the consolidated financial statements. The Company has announced internal greenhouse gas reduction targets and closely monitors regulatory initiatives that may impact its existing businesses. The impact of these changes are 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), formerly the National Energy Board (NEB), the Alberta Energy Regulator or the B.C. Oil and Gas Commission. In the U.S., regulated natural gas pipelines, liquids pipelines and regulated natural gas storage assets are subject to the authority of the Federal Energy Regulatory Commission (FERC). In Mexico, regulated natural gas pipelines are subject to the authority of the Energy Regulatory Commission (CRE). Rate-regulated accounting (RRA) standards may impact the timing of the recognition of certain revenues and expenses in TC Energy's rate-regulated businesses which may differ from that otherwise recognized in non-rate-regulated businesses to reflect the economic impact of the regulators' decisions regarding revenues and tolls. Regulatory assets represent costs that are expected to be recovered in customer rates in future periods and regulatory liabilities represent amounts that are expected to be returned to customers through future rate-setting processes. An operation qualifies for the use of RRA when it meets three criteria:

- a regulator must establish or approve the rates for the regulated services or activities
- the regulated rates must be designed to recover the cost of providing the services or products and
- 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.

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.

During 2019, TC Energy sold certain Columbia Midstream assets that were part of the acquisition of Columbia Pipeline Group, Inc.(Columbia) in 2016. Prior to the sale, revenues from the Company's midstream natural gas services, including gathering, treating, conditioning, processing, compression and liquids handling services, were generated from contractual arrangements and were recognized ratably over the term of the contract. Midstream natural gas service revenues were invoiced and received on a monthly basis. The Company did not take ownership of the natural gas for which it provided midstream services. Refer to Note 28, Acquisitions and dispositions, for additional information regarding the sale of the Columbia Midstream assets.

Mexico Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from 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 is contracted to provide operating services to a partially-owned entity for a fee which is recognized over time as services are provided. The Company's construction services to this entity have been performed and the related development fee has been recognized.

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 Storage

Power

Revenues from the Company's Power and Storage 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 and proprietary natural gas inventory in storage. 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 0.6 per cent to seven 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.

Prior to its sale in 2019, plant, property and equipment for Columbia Midstream was carried at cost. Depreciation was calculated on a straight-line basis once the assets were ready for their intended use. Gathering and processing facilities were depreciated at annual rates ranging from 1.7 per cent to 2.5 per cent, and other plant and equipment were depreciated at various rates reflecting their estimated useful lives. When these assets were retired from plant, property and equipment, the original book cost and related accumulated depreciation were derecognized and any gain or loss was recorded in net income. Refer to Note 28, Acquisitions and dispositions, for additional information.

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 Storage

Plant, property and equipment for Power and Storage 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 a construction stage is probable or costs are otherwise likely to be recoverable. The Company also 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

Lessee Accounting Policy

The Company determines if an arrangement is a lease at inception of the contract. 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 expedients to not recognize ROU assets or lease liabilities for leases that qualify for the short-term lease recognition exemption and to not separate lease and non-lease components for all leases for which the Company is a lessee.

Lessor Accounting Policy

The Company is the lessor within certain contracts, including power purchase agreements (PPA), and these are accounted for as operating leases. The Company recognizes lease payments as income over the lease term on a straight-line basis. Variable lease payments are recognized as income in the period in which they occur.

The Company applies the practical expedient to not separate lease and non-lease components for facilities and liquids tank terminals for which the Company is the lessor.

Impairment of Long-Lived Assets

The Company reviews long-lived assets such as plant, property and equipment, equity investments 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.

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.

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.

Loans and Receivables

Loans receivable from affiliates and accounts receivable are measured at amortized cost.

Impairment of Financial Assets

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 supportable forecasts to determine any impairment, which is recognized in Plant operating costs and other.

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.

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

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. Amounts expected to be recovered from other parties, including insurers, are recorded as an asset separate from the associated liability.

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 in the Consolidated statement of income.

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. 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 other post-retirement benefits 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 period-end exchange rates while revenues, expenses, gains and losses are translated at the exchange rates in effect at the time 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 and 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 on 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.

3. ACCOUNTING CHANGES

Changes in Accounting Policies for 2021

Income Taxes

In December 2019, the Financial Accounting Standards Board (FASB) issued new guidance that simplified the accounting for income taxes and clarified existing guidance. This new guidance was effective January 1, 2021, and did not have a material impact on the Company's consolidated financial statements.

Reference Rate Reform

In response to the expected cessation of the U.S. dollar London Interbank Offered Rate (LIBOR), for which certain rate settings ceased to be published at the end of 2021 with full cessation by mid-2023, the FASB issued new optional guidance in March 2020 that eases the potential burden in accounting for such reference rate reform. The new guidance provides optional expedients for contracts and hedging relationships that are affected by reference rate reform if certain criteria are met. Each of the expedients can be applied as of January 1, 2020 through December 31, 2022. For eligible hedging relationships existing as of January 1, 2020 and prospectively, the Company has applied an optional expedient allowing an entity to assume that the hedged forecasted transaction in a cash flow hedge is probable of occurring. The Company has completed necessary system changes to facilitate the adoption of the proposed standard market reference rates. The Company has also completed its analysis of contracts impacted by reference rate reform. Contract modifications, if required, will take place prior to the full cessation date in mid-2023. The Company expects to use practical expedients available in the guidance to treat contract modifications as events that do not require contract remeasurement or reassessment of previous accounting determinations. As such, these changes are not expected to have a material impact on the consolidated financial statements; however, the Company will continue to monitor any new developments up to the full cessation date.

Future Accounting Changes

Government Assistance

In November 2021, the FASB issued new guidance that expands annual disclosure requirements for entities that account for a transaction with a government by applying a grant or contribution accounting model by analogy to other accounting guidance. Entities are required to disclose the nature of the transactions, the related accounting policies used to account for the transactions, the effect of the transactions on an entity's financial statements, and any significant terms and conditions of the transaction. This new guidance is effective for annual disclosure requirements at December 31, 2022 and can be applied either prospectively or retrospectively, with early application permitted. The Company is currently evaluating the impact of the adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

Contract Assets and Liabilities from Contracts with Customers

In October 2021, the FASB issued new guidance that amends the accounting for contract assets and liabilities from contracts with customers acquired in a business combination. At the acquisition date, an acquirer should account for the contract assets and liabilities in accordance with guidance on revenue from contracts with customers. This new guidance is effective January 1, 2023 and is applied prospectively with early adoption permitted. Early adoption requires the application of the amendments retrospectively to all business combinations with an acquisition date in the year of early adoption. The Company is currently evaluating the timing of the adoption of this guidance.

4. SEGMENTED 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 Storage	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 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)
Asset impairment charge and other	—	—	—	(2,775)	—	—	(2,775)
Gain 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
Interest income and other[3]							200
Income before Income Taxes							2,166
Income tax expense							(120)
Net Income							2,046
Net income attributable to non-controlling interests							(91)
Net Income Attributable to Controlling Interests							1,955
Preferred share dividends							(140)
Net Income Attributable to Common Shares							1,815
Capital Spending							
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 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 Interest income and other by the corresponding foreign exchange losses and gains on the affiliate receivable balance. Refer to Note 11, Loans receivable from affiliates, for additional information.

year ended December 31, 2020 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Corporate[1]	Total
Revenues	4,469	5,031	716	2,371	412	—	12,999
Intersegment revenues	—	165	—	—	20	(185) [2]	—
	4,469	5,196	716	2,371	432	(185)	12,999
Income from equity investments	12	264	127	75	455	86 [3]	1,019
Plant operating costs and other	(1,631)	(1,485)	(57)	(654)	(220)	169 [2]	(3,878)
Property taxes	(284)	(337)	—	(101)	(5)	—	(727)
Depreciation and amortization	(1,273)	(801)	(117)	(332)	(67)	—	(2,590)
Net gain/(loss) on sale of assets	364	—	—	—	(414)	—	(50)
Segmented Earnings	1,657	2,837	669	1,359	181	70	6,773
Interest expense							(2,228)
Allowance for funds used during construction							349
Interest income and other[3]							213
Income before Income Taxes							5,107
Income tax expense							(194)
Net Income							4,913
Net income attributable to non-controlling interests							(297)
Net Income Attributable to Controlling Interests							4,616
Preferred share dividends							(159)
Net Income Attributable to Common Shares							4,457
Capital Spending							
Capital expenditures	3,503	2,785	173	1,315	179	58	8,013
Capital projects in development	—	—	—	122	—	—	122
Contributions to equity investments	105	—	—	5	655	—	765
	3,608	2,785	173	1,442	834	58	8,900

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 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 Interest income and other by the corresponding foreign exchange losses and gains on the affiliate receivable balance. Refer to Note 11, Loans receivable from affiliates, for additional information.

year ended December 31, 2019 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Corporate[1]	Total
Revenues	4,010	4,978	603	2,879	785	—	13,255
Intersegment revenues	—	164	—	—	19	(183) [2]	—
	4,010	5,142	603	2,879	804	(183)	13,255
Income/(loss) from equity investments	12	264	56	70	571	(53) [3]	920
Plant operating costs and other	(1,473)	(1,581)	(54)	(728)	(243)	166 [2]	(3,913)
Commodity purchases resold	—	—	—	—	(365)	—	(365)
Property taxes	(275)	(345)	—	(101)	(6)	—	(727)
Depreciation and amortization	(1,159)	(754)	(115)	(341)	(95)	—	(2,464)
Net gain/(loss) on assets sold/held for sale	—	21	—	69	(211)	—	(121)
Segmented Earnings/(Losses)	1,115	2,747	490	1,848	455	(70)	6,585
Interest expense							(2,333)
Allowance for funds used during construction							475
Interest income and other[3]							460
Income before Income Taxes							5,187
Income tax expense							(754)
Net Income							4,433
Net income attributable to non-controlling interests							(293)
Net Income Attributable to Controlling Interests							4,140
Preferred share dividends							(164)
Net Income Attributable to Common Shares							3,976
Capital Spending							
Capital expenditures	3,900	2,500	323	239	481	32	7,475
Capital projects in development	6	—	—	701	—	—	707
Contributions to equity investments	—	16	34	14	538	—	602
	3,906	2,516	357	954	1,019	32	8,784

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 Interest income and other by the corresponding foreign exchange losses and gains on the affiliate receivable balance. Refer to Note 11, Loans receivable from affiliates, for additional information.

at December 31 (millions of Canadian $)	2021	2020
Total Assets by segment		
Canadian Natural Gas Pipelines	**25,213**	22,852
U.S. Natural Gas Pipelines	**45,502**	43,217
Mexico Natural Gas Pipelines	**7,547**	7,215
Liquids Pipelines	**14,951**	16,744
Power and Storage	**6,563**	5,062
Corporate	**4,442**	5,210
	104,218	100,300

Geographic Information

year ended December 31 (millions of Canadian $)	2021	2020	2019
Revenues			
Canada – domestic	**4,603**	4,392	4,059
Canada – export	**1,226**	1,059	1,035
United States	**6,953**	6,832	7,558
Mexico	**605**	716	603
	13,387	12,999	13,255

at December 31 (millions of Canadian $)	2021	2020
Plant, Property and Equipment		
Canada	**24,890**	24,092
United States	**39,335**	39,698
Mexico	**5,957**	5,985
	70,182	69,775

5. REVENUES

Disaggregation of Revenues

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 Storage	Total
Revenues from contracts with customers						
Capacity arrangements and transportation	**4,432**	**4,139**	**576**	**2,025**	**—**	**11,172**
Power generation	**—**	**—**	**—**	**—**	**324**	**324**
Natural gas storage and other[1]	**87**	**1,057**	**29**	**5**	**278**	**1,456**
	4,519	**5,196**	**605**	**2,030**	**602**	**12,952**
Other 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 development and construction of the Coastal GasLink pipeline project which is 35 per cent owned by TC Energy as at December 31, 2021. Refer to Note 28, Acquisitions and dispositions, for additional information.

2 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements. Refer to Note 9, Leases, and Note 26, Risk management and financial instruments, for additional information on income from lease arrangements and financial instruments, respectively.

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 12, Rate-regulated businesses, for additional information.

year ended December 31, 2020 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Total
Revenues from contracts with customers						
Capacity arrangements and transportation	4,408	4,301	607	2,206	—	11,522
Power generation	—	—	—	—	192	192
Natural gas storage and other[1]	61	654	109	3	106	933
	4,469	4,955	716	2,209	298	12,647
Other revenues[2,3]	—	76	—	162	114	352
	4,469	5,031	716	2,371	412	12,999

1 Includes $138 million of fee revenues from affiliates, of which $77 million was related to the construction of the Sur de Texas pipeline which is 60 per cent owned by TC Energy and $61 million was related to development and construction of the Coastal GasLink pipeline project which is 35 per cent owned by TC Energy as at December 31, 2020. Refer to Note 28, Acquisitions and dispositions, for additional information.

2 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements. Refer to Note 9, Leases, and Note 26, Risk management and financial instruments, for additional information on income from lease arrangements and financial instruments, respectively.

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 12, Rate-regulated businesses, for additional information.

year ended December 31, 2019 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Total
Revenues from contracts with customers						
Capacity arrangements and transportation	4,010	4,245	601	2,423	—	11,279
Power generation	—	—	—	—	662	662
Natural gas storage and other	—	650	2	4	73	729
	4,010	4,895	603	2,427	735	12,670
Other revenues[1,2]	—	83	—	452	50	585
	4,010	4,978	603	2,879	785	13,255

1 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements. Refer to Note 9, Leases, and Note 26, Risk management and financial instruments, for additional information on income from lease arrangements and financial instruments, respectively.

2 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 12, Rate-regulated businesses, for additional information.

Contract Balances

at December 31 (millions of Canadian $)	2021	2020	Affected line item on the Consolidated balance sheet
Receivables from contracts with customers	**1,627**	1,330	Accounts receivable
Contract assets (Note 7)	**202**	132	Other current assets
Long-term contract assets (Note 14)	**249**	192	Other long-term assets
Contract liabilities[1] (Note 16)	**90**	129	Accounts payable and other
Long-term contract liabilities (Note 17)	**184**	203	Other long-term liabilities

1 During the year ended December 31, 2021, $15 million (2020 – $18 million) of revenues were recognized that were included in 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 relate to force majeure fixed capacity payments received on long-term capacity arrangements in Mexico.

Future Revenues from Remaining Performance Obligations

As at December 31, 2021, future revenues from long-term pipeline capacity arrangements and transportation as well as natural gas storage and other contracts extending through 2049 are approximately $23.8 billion, of which approximately $3.4 billion is expected to be recognized in 2022.

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.

6. KEYSTONE XL

Asset Impairment Charge and Other

Following the revocation of the Presidential Permit for the Keystone XL pipeline project on January 20, 2021, and after a comprehensive review of options in consultation with its partner, the Government of Alberta, on June 9, 2021, the Company terminated the Keystone XL pipeline project. The Keystone XL investment was evaluated for impairment in 2021, along with TC Energy's investments in related capital projects, including Heartland Pipeline, TC Terminals and Keystone Hardisty Terminal. 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. Termination activities and related costs will continue through 2022 with any adjustments to the estimated fair value and future contractual and legal obligations expensed as determined.

year ended December 31, 2021	Estimated Fair Value of Plant, Property and Equipment	Asset impairment charge and other	
(millions of Canadian $)		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[1]	**n/a**	**342**	**282**
	175	**2,775**	**2,134**

1 In 2021, the Company paid $192 million towards contractual and legal obligations related to termination activities.

The estimated fair value of $175 million related to plant and equipment is based on the price that is expected to be received from selling these assets in their current condition and is updated as required. 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.

As the Company did not see the related capital projects in development proceeding at the time of the assessment in 2021, it recorded an asset impairment charge equal to the carrying value of these projects included in Other long-term assets on the Consolidated balance sheet as the estimated fair value of these related projects was determined to be nil.

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. At December 31, 2020, TC Energy had reclassified $630 million related to Class A Interests to Current liabilities on the Consolidated balance sheet to reflect the expectation that the Company would exercise its call right in January 2021 in accordance with contractual terms. For the year ended December 31, 2020, redeemable non-controlling interest in Current liabilities of $633 million also included $3 million of return accrued that was recorded in Interest expense in the Consolidated statement of income.

On January 8, 2021, the Company exercised its call right 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 which were classified as Current liabilities on the Consolidated balance sheet at December 31, 2020. This transaction was funded by draws on the project-level credit facility. Following the revocation of the Presidential Permit for the Keystone XL pipeline project on January 20, 2021, the Company ceased accruing a return on the remaining Government of Alberta Class A Interests. 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. 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) and in accordance with the terms of the guarantee, the Government of Alberta repaid the full outstanding balance in June 2021 and it was subsequently terminated. As part of this arrangement, TC Energy issued $91 million of Class C Interests in the Keystone XL subsidiaries which entitle the Government of Alberta to future liquidation proceeds from specified Keystone XL project assets. The Class C Interests of $91 million, net of $16 million of related distributions to the Government of Alberta, were recorded in Accounts payable and other on the Consolidated balance sheet at December 31, 2021. 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 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.

The changes in Redeemable non-controlling interest classified in mezzanine equity were as follows:

year ended December 31 (millions of Canadian $)	2021	2020
Balance at beginning of year	**393**	—
Class A Interests issued	**—**	1,033
Net income/(loss) attributable to redeemable non-controlling interest[1]	**1**	(10)
Class A Interests repurchased	**(394)**	—
Class A Interests transferred to Current liabilities	**—**	(630)
Balance at end of year	**—**	393

1 Includes a return accrual and a foreign currency translation loss on Class A Interests, both of which were presented within Net income attributable to non-controlling interests in the Consolidated statement of income.

7. OTHER CURRENT ASSETS

at December 31 (millions of Canadian $)	2021	2020
Keystone XL contractual recoveries (Note 6)	**640**	—
Cash provided as collateral	**273**	142
Contract assets (Note 5)	**202**	132
Fair value of derivative contracts (Note 26)	**169**	235
Keystone XL assets held for sale	**138**	—
Prepaid expenses	**112**	126
Regulatory assets (Note 12)	**53**	131
Other	**130**	114
	1,717	880

8. PLANT, PROPERTY AND EQUIPMENT

at December 31	2021			2020		
(millions of Canadian $)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Canadian Natural Gas Pipelines						
NGTL System						
Pipeline	**14,892**	**5,751**	**9,141**	14,190	5,278	8,912
Compression	**6,191**	**2,065**	**4,126**	5,421	1,906	3,515
Metering and other	**1,458**	**705**	**753**	1,393	648	745
	22,541	**8,521**	**14,020**	21,004	7,832	13,172
Under construction	**2,285**	**—**	**2,285**	1,402	—	1,402
	24,826	**8,521**	**16,305**	22,406	7,832	14,574
Canadian Mainline						
Pipeline	**10,423**	**7,698**	**2,725**	10,297	7,443	2,854
Compression	**4,165**	**3,125**	**1,040**	3,930	3,000	930
Metering and other	**652**	**264**	**388**	637	239	398
	15,240	**11,087**	**4,153**	14,864	10,682	4,182
Under construction	**139**	**—**	**139**	150	—	150
	15,379	**11,087**	**4,292**	15,014	10,682	4,332
Other Canadian Natural Gas Pipelines[1]						
Other	**1,937**	**1,567**	**370**	1,885	1,508	377
Under construction	**58**	**—**	**58**	42	—	42
	1,995	**1,567**	**428**	1,927	1,508	419
	42,200	**21,175**	**21,025**	39,347	20,022	19,325
U.S. Natural Gas Pipelines						
Columbia Gas						
Pipeline	**11,205**	**799**	**10,406**	10,198	557	9,641
Compression	**4,522**	**381**	**4,141**	4,287	276	4,011
Metering and other	**3,657**	**257**	**3,400**	3,388	185	3,203
	19,384	**1,437**	**17,947**	17,873	1,018	16,855
Under construction	**433**	**—**	**433**	1,070	—	1,070
	19,817	**1,437**	**18,380**	18,943	1,018	17,925
ANR						
Pipeline	**1,820**	**557**	**1,263**	1,685	512	1,173
Compression	**2,559**	**565**	**1,994**	2,146	489	1,657
Metering and other	**1,391**	**422**	**969**	1,289	388	901
	5,770	**1,544**	**4,226**	5,120	1,389	3,731
Under construction	**833**	**—**	**833**	431	—	431
	6,603	**1,544**	**5,059**	5,551	1,389	4,162

at December 31	2021			2020		
(millions of Canadian $)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Other U.S. Natural Gas Pipelines						
Columbia Gulf	**2,749**	**178**	**2,571**	2,638	151	2,487
GTN	**2,701**	**1,071**	**1,630**	2,330	1,008	1,322
Great Lakes	**2,162**	**1,255**	**907**	2,117	1,223	894
Other[2]	**1,755**	**657**	**1,098**	1,568	578	990
	9,367	**3,161**	**6,206**	8,653	2,960	5,693
Under construction	**533**	**—**	**533**	389	—	389
	9,900	**3,161**	**6,739**	9,042	2,960	6,082
	36,320	**6,142**	**30,178**	33,536	5,367	28,169
Mexico Natural Gas Pipelines						
Pipeline	**2,957**	**476**	**2,481**	2,952	411	2,541
Compression	**480**	**80**	**400**	480	69	411
Metering and other	**626**	**155**	**471**	624	133	491
	4,063	**711**	**3,352**	4,056	613	3,443
Under construction	**2,590**	**—**	**2,590**	2,525	—	2,525
	6,653	**711**	**5,942**	6,581	613	5,968
Liquids Pipelines						
Keystone Pipeline System						
Pipeline	**9,209**	**1,758**	**7,451**	9,254	1,579	7,675
Pumping equipment	**1,020**	**252**	**768**	1,025	228	797
Tanks and other	**3,534**	**737**	**2,797**	3,522	644	2,878
	13,763	**2,747**	**11,016**	13,801	2,451	11,350
Under construction[3]	**72**	**—**	**72**	2,870	—	2,870
	13,835	**2,747**	**11,088**	16,671	2,451	14,220
Intra-Alberta Pipelines	**199**	**14**	**185**	198	9	189
	14,034	**2,761**	**11,273**	16,869	2,460	14,409
Power and Storage						
Natural Gas	**1,267**	**605**	**662**	1,255	569	686
Natural Gas Storage and Other	**797**	**216**	**581**	780	194	586
	2,064	**821**	**1,243**	2,035	763	1,272
Under construction	**5**	**—**	**5**	11	—	11
	2,069	**821**	**1,248**	2,046	763	1,283
Corporate	**836**	**320**	**516**	993	372	621
	102,112	**31,930**	**70,182**	99,372	29,597	69,775

1 Includes Foothills, Ventures LP and Great Lakes Canada.
2 Includes Portland, North Baja, Tuscarora, Crossroads and mineral rights.
3 Following the revocation of the Presidential Permit for the Keystone XL pipeline project on January 20, 2021, the Company recognized a pre-tax asset impairment charge of $3,126 million, of which $2,896 million was related to Keystone XL assets under construction and $230 million was related to associated capital projects in development. Refer to Note 6, Keystone XL, for additional information.

9. LEASES

As a Lessee

The Company has operating leases for corporate offices, other various premises, equipment and land. Some leases have an option to renew for periods of one to 25 years, and some may include options to terminate the lease within one year. 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 $)	2021	2020
Operating lease cost[1]	**105**	124
Sublease income	**(8)**	(13)
Net operating lease cost	**97**	111

1 Includes short-term leases and variable lease costs.

Other information related to operating leases is noted in the following tables:

year ended December 31 (millions of Canadian $)	2021	2020
Cash paid for amounts included in the measurement of operating lease liabilities	**69**	77
ROU assets obtained in exchange for new operating lease liabilities	**32**	14

at December 31	2021	2020
Weighted average remaining lease term	**9 years**	10 years
Weighted average discount rate	**3.5 %**	3.5 %

Maturities of operating lease liabilities are as follows:

(millions of Canadian $)	2021	2020
Less than one year	**63**	72
One to two years	**60**	61
Two to three years	**58**	59
Three to four years	**55**	58
Four to five years	**54**	54
More than five years	**213**	269
Total operating lease payments	**503**	573
Imputed interest	**(74)**	(90)
Operating lease liabilities	**429**	483

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

at December 31 (millions of Canadian $)	2021	2020
Accounts payable and other	**49**	56
Other long-term liabilities (Note 17)	**380**	427
	429	483

As at December 31, 2021, the carrying value of the ROU assets recorded under operating leases was $415 million (2020 – $473 million) and is included in Plant, property and equipment on the Consolidated balance sheet.

As a Lessor

The Grandview and Bécancour power plants in the Power and Storage 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 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, 2021 was $126 million (2020 – $130 million; 2019 – $180 million).

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

(millions of Canadian $)	2021	2020
Less than one year	**113**	119
One to two years	**111**	111
Two to three years	**110**	109
Three to four years	**94**	109
Four to five years	**70**	94
More than five years	**—**	70
	498	612

The cost and accumulated depreciation for facilities accounted for as operating leases was $812 million and $340 million, respectively, at December 31, 2021 (2020 – $858 million and $327 million, respectively).

10. EQUITY INVESTMENTS

(millions of Canadian $)	Ownership Interest at December 31, 2021	Income from Equity Investments year ended December 31			Equity Investments at December 31	
		2021	**2020**	**2019**	**2021**	**2020**
Canadian Natural Gas Pipelines						
TQM[1]	50.0 %	**12**	12	12	**118**	90
Coastal GasLink[1,2]	35.0 %	**—**	—	—	**386**	211
U.S. Natural Gas Pipelines						
Northern Border[3]	50.0 %	**80**	100	91	**505**	521
Millennium	47.5 %	**91**	96	92	**474**	482
Iroquois[4]	50.0 %	**55**	52	54	**392**	197
Other	Various	**18**	16	27	**137**	120
Mexico Natural Gas Pipelines						
Sur de Texas[5]	60.0 %	**160**	213	3	**835**	680
Liquids Pipelines						
Grand Rapids[1,6]	50.0 %	**54**	53	56	**980**	998
Northern Courier[1,7]	nil	**16**	22	14	**—**	53
Port Neches Link LLC[1,8]	95.0 %	**—**	—	—	**103**	—
HoustonLink Pipeline[1]	50.0 %	**1**	—	—	**18**	19
Power and Storage						
Bruce Power[1,9]	48.4 %	**411**	439	527	**4,493**	3,306
Portlands Energy Centre[1,10]	nil	**—**	12	35	**—**	—
TransCanada Turbines[11]	100.0 %	**—**	4	9	**—**	—
		898	1,019	920	**8,441**	6,677

1 Classified as a non-consolidated VIE. Refer to Note 30, Variable interest entities, for additional information.

2 In May 2020, TC Energy completed the sale of a 65 per cent equity interest in Coastal GasLink Pipeline Limited Partnership and subsequently applied the equity method to account for its 35 per cent retained equity interest in the jointly-controlled entity. Refer to Note 28, Acquisitions and dispositions, for additional information. At December 31, 2021, the difference between the carrying value of the investment and the underlying equity in the net assets of Coastal GasLink Pipeline Limited Partnership was $167 million (2020 – $188 million) due mainly to the fair value assessment of assets at the time of partial monetization along with deferred development fee revenue accounting.

3 At December 31, 2021, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Border was US$115 million (2020 – US$116 million) due mainly to the fair value assessment of assets at the time of acquisition.

4 At December 31, 2021, the difference between the carrying value of the investment and the underlying equity in the net assets of Iroquois was US$39 million (2020 – US$39 million) due mainly to the fair value assessment of the assets at the times of acquisition.

5 Sur de Texas was placed into service in September 2019. TC Energy has a 60 per cent equity interest and, as a jointly-controlled entity, applies the equity method of accounting. Income from equity investments recorded in the Corporate segment reflects 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 Interest income and other in the Consolidated statement of income. At December 31, 2021, the difference between the carrying value of the investment and the underlying equity in the net assets of Sur de Texas was US$77 million (2020 – US$79 million) due mainly to the accounting for fees earned from the successful construction of the pipeline.

6 At December 31, 2021, the difference between the carrying value of the investment and the underlying equity in the net assets of Grand Rapids was $96 million (2020 – $98 million) due mainly to interest capitalized during construction.

7 On November 30, 2021, TC Energy sold its remaining 15 per cent equity interest in Northern Courier. Refer to Note 28, Acquisitions and dispositions, for additional information. At December 31, 2020, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Courier was $56 million due mainly to the fair value of guarantees and the fair value assessment of assets at the time of partial monetization.

8 On March 8, 2021, TC Energy entered a joint venture with Motiva Enterprises to construct the Port Neches Link pipeline system. TC Energy has a 95 per cent equity interest and, as a jointly-controlled entity, applies the equity method of accounting.

9 At December 31, 2021, the difference between the carrying value of the investment and the underlying equity in the net assets of Bruce Power was $755 million (2020 – $796 million) due mainly to capitalized interest and the fair value assessment of assets at the time of acquisition.

10 In April 2020, TC Energy sold its investment in Portlands Energy Centre. Refer to Note 28, Acquisitions and dispositions, for additional information.

11 In November 2020, TC Energy purchased the remaining 50 per cent ownership in TransCanada Turbines which was subsequently consolidated. Refer to Note 28, Acquisitions and dispositions, for additional information.

Distributions and Contributions

Distributions received from equity investments for the year ended December 31, 2021 were $1,048 million (2020 – $1,123 million; 2019 – $1,399 million). For the year ended December 31, 2021, $73 million (2020 – nil; 2019 – $186 million) was included in Investing activities in the Consolidated statement of cash flows relating to TC Energy's proportionate share of the Sur de Texas 2021 partial debt repayment, and in 2019, included distributions received from Bruce Power and Northern Border from their respective financing programs.

Contributions made to equity investments for the year ended December 31, 2021 were $1,210 million (2020 – $765 million; 2019 – $602 million) and were included in Investing activities in the Consolidated statement of cash flows. For 2019, contributions of $32 million related to TC Energy's proportionate share of the Sur de Texas debt financing requirements.

Summarized Financial Information of Equity Investments

year ended December 31			
(millions of Canadian $)	**2021**	**2020**	**2019**
Income			
Revenues	**5,447**	5,838	5,693
Operating and other expenses	**(3,293)**	(3,341)	(3,408)
Net income	**1,859**	2,047	1,990
Net income attributable to TC Energy	**898**	1,019	920

at December 31		
(millions of Canadian $)	**2021**	**2020**
Balance Sheet		
Current assets	**3,498**	2,911
Non-current assets	**30,165**	26,957
Current liabilities	**(2,540)**	(3,727)
Non-current liabilities	**(16,400)**	(15,309)

11. 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.

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 bears interest at a floating rate and matures in March 2022. At December 31, 2021, Loans receivable from affiliates under Current assets on the Company's Consolidated balance sheet reflected a MXN$19.7 billion or $1.2 billion loan receivable from the Sur de Texas joint venture which represents TC Energy's proportionate share of debt financing to the joint venture. At December 31, 2020, this loan was recorded as Long-term loans receivable from affiliates on the Company's Consolidated balance sheet and amounted to MXN$20.9 billion or $1.3 billion.

The Company's Consolidated statement of income reflects the related interest income and foreign exchange impact on this loan receivable 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 $)	**2021**	**2020**	**2019**	**Affected line item in the Consolidated statement of income**
Interest income[1]	**87**	110	147	Interest income and other
Interest expense[2]	**(87)**	(110)	(147)	Income from equity investments
Foreign exchange (losses)/gains[1]	**(41)**	(86)	53	Interest income and other
Foreign exchange gains/(losses)[1]	**41**	86	(53)	Income from equity investments

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

Coastal GasLink Pipeline Limited Partnership

TC Energy holds a 35 per cent equity interest in Coastal GasLink Pipeline Limited Partnership (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 had a capacity of $500 million at December 31, 2021 with an outstanding balance of $1 million (December 31, 2020 – nil) reflected in Loans receivable from affiliates under Current assets on the Company's Consolidated balance sheet.

Subordinated Loan Agreement

On December 6, 2021, the Company entered into a subordinated loan agreement with Coastal GasLink LP to provide interim temporary financing, if necessary, of up to $3,275 million to fund incremental project costs as a bridge to a required increase in the project-level financing. Financing available to Coastal GasLink LP under this agreement is provided through a combination of interest-bearing facilities subject to floating market-based rates and non-interest-bearing facilities that are subject to a return to the Company under certain conditions at the time the final cost of the project is determined. At December 31, 2021, Long-term loans receivable from affiliates on the Company's Consolidated balance sheet reflected $238 million in amounts outstanding under the subordinated loan agreement.

12. RATE-REGULATED BUSINESSES

TC Energy's businesses that apply RRA currently include almost all of the Canadian, U.S. and Mexico natural gas pipelines and certain U.S. natural gas storage operations. Rate-regulated businesses account for and report assets and liabilities consistent with the resulting economic impact of the 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). In August 2019, the CER and CER Act replaced the NEB and the National Energy Board Act, respectively. The impact assessment and decision-making for designated major transboundary pipeline projects also changed at that time with the implementation of the new Impact Assessment Act which required designated projects, on a prospective basis, to be assessed by the Impact Assessment Agency of Canada.

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 or NEB. 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 regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Differences between actual and forecasted costs that the regulator does not allow to be deferred are included in the determination of net income in the year they occur. The Company's most significant regulated Canadian natural gas pipelines, based on total operated pipe length, are described below.

NGTL System

The NGTL System currently operates under the terms of the 2020-2024 Revenue Requirement Settlement which includes an ROE of 10.1 per cent on 40 per cent deemed common equity, 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 between the NGTL System and its customers.

NGTL System's 2019 results reflect the terms of the 2018-2019 Revenue Requirement Settlement which included an ROE of 10.1 per cent on 40 per cent deemed common equity, a mechanism for sharing variances above and below a fixed annual operating, maintenance and administration amount and flow-through treatment of all other costs.

Canadian Mainline

The Canadian Mainline currently operates under the terms of the 2015-2030 Tolls Application approved in 2014 (the NEB 2014 Decision). The terms in the 2015-2020 six-year settlement of the NEB 2014 Decision, which ended December 31, 2020, included an ROE of 10.1 per cent on 40 per cent deemed common equity, an incentive mechanism that had both upside and downside risk and a $20 million after-tax annual TC Energy contribution to reduce the revenue requirement. Toll stabilization was achieved through the use of deferral accounts, namely the bridging amortization account and the long-term adjustment account (LTAA), to capture the surplus or shortfall between the Company's revenues and cost of service for each year over the 2015-2020 six-year fixed-toll term of the NEB 2014 Decision. The NEB 2014 Decision also directed TC Energy to file an application to review tolls for the 2018-2020 period. In December 2018, an NEB decision was received on the 2018-2020 Tolls Review which included an accelerated amortization of the December 31, 2017 LTAA balance and an increase to the composite depreciation rate from 3.2 per cent to 3.9 per cent.

In April 2020, the CER approved the six-year unanimous negotiated settlement (2021-2026 Mainline Settlement) effective January 1, 2021. Similar to previous settlements, 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 the shippers and TC Energy. An estimate of the remaining LTAA balance at the end of 2020 was included as an adjustment in the calculation of Mainline fixed tolls and amortized over the settlement term. Similar to the LTAA, the short-term adjustment accounts (STAA) captures the surplus or shortfall between system revenues and cost of service each year under the 2021-2026 Mainline Settlement and the Company will commence amortization over the remaining settlement term when predetermined thresholds per the settlement agreement are met.

U.S. Regulated Operations

TC Energy's U.S. regulated natural gas pipelines operate under the provisions of the Natural Gas Act (NGA) of 1938, 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 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.

In 2018, FERC prescribed changes (2018 FERC Actions) related to H.R.1, the Tax Cuts and Jobs Act (U.S. Tax Reform). The U.S. corporate income tax rate was reduced from 35 per cent to 21 per cent in 2017 as a result of U.S. Tax Reform. The U.S. regulated operations, where applicable, established regulatory liabilities amortized over the remaining average useful lives of the underlying property for the differences between the amounts previously recovered in rates and the expected deferred tax liabilities.

Columbia Gas

Columbia Gas' natural gas transportation and storage services are provided under a tariff at rates subject to FERC approval. A FERC-approved modernization settlement provided for cost recovery and return on investment of up to US$2.6 billion from 2013-2020 to modernize the Columbia Gas system thereby improving system integrity and enhancing service reliability and flexibility.

In July 2020, Columbia Gas filed a general NGA Section 4 Rate Case with FERC requesting an increase on its maximum transportation rates to be effective February 1, 2021, subject to refund on completion of the rate proceeding. On October 29, 2021, Columbia Gas filed a petition with FERC requesting approval of the Stipulation and Agreement of Settlement (Columbia Gas Settlement) that reflects a rate case settlement with its customers and, if approved, will increase Columbia Gas' maximum rates effective February 1, 2021. On December 17, 2021, the presiding Administrative Law Judge recommended the settlement for approval and certified it as uncontested to FERC for its review and approval. The Columbia Gas Settlement (a) extends Columbia's modernization program allowing for the cost recovery and return on additional investment of up to US$1.2 billion over a four-year period through 2024 (b) establishes a rate case and tariff filing moratorium through April 1, 2025 and (c) requires Columbia Gas to file a general rate case under Section 4 of the NGA with new rates to be effective no later than April 1, 2026.

ANR Pipeline

ANR Pipeline operates under rates established through a FERC-approved rate settlement in 2016. To meet terms of the 2016 settlement, on January 28, 2022, ANR Pipeline filed a Section 4 Rate Case with FERC requesting an increase to maximum transportation rates effective August 1, 2022, subject to refund. As the rate process progresses, the Company expects to engage in a collaborative process to achieve settlement with its customers, FERC and other stakeholders.

Columbia Gulf

Columbia Gulf reached a rate settlement with its customers, which was approved by FERC in December 2019, increasing Columbia Gulf's recourse rates to take effect on August 1, 2020. This settlement establishes a rate case and tariff filing moratorium through August 1, 2022 and Columbia Gulf is required to file a general rate case under Section 4 of the NGA no later than January 31, 2027, with new rates to be effective August 1, 2027.

Great Lakes

Great Lakes operates under a settlement approved by FERC in February 2018 which does not include a moratorium. However, Great Lakes will be required to file for new rates no later than March 31, 2022, with new rates to be effective October 1, 2022.

As a result of the 2018 FERC Actions, Great Lakes made a limited NGA Section 4 filing and reduced rates by two per cent effective February 1, 2019.

Gas Transmission Northwest

Gas Transmission Northwest (GTN) operates under a settlement approved by FERC in November 2018. GTN and its customers agreed upon a moratorium on further rate changes until December 31, 2021 and GTN is required to have new rates in effect on January 1, 2022.

On September 29, 2021, GTN filed a rate settlement (2021 GTN Settlement) which was approved by FERC on November 18, 2021, extending the Company's existing maximum transportation rates at their current levels, with GTN's annual depreciation rates remaining unchanged. The 2021 GTN Settlement contains a moratorium until December 31, 2023, at which point GTN will be required to file for new rates to become effective no later than April 1, 2024.

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 were established based on CRE-approved contracts that provide for cost recovery, including a return of and on invested capital.

Regulatory Assets and Liabilities

at December 31 (millions of Canadian $)	2021	2020	Remaining Recovery/ Settlement Period (years)
Regulatory Assets			
Deferred income taxes[1]	**1,509**	1,287	n/a
Pensions and other post-retirement benefits[1,2]	**203**	401	n/a
Foreign exchange on long-term debt[1,3]	**3**	7	1-8
Operating and debt-service regulatory assets[4]	**1**	54	1
Other	**104**	135	n/a
	1,820	1,884	
Less: Current portion included in Other current assets (Note 7)	**53**	131	
	1,767	1,753	
Regulatory Liabilities			
Pipeline abandonment trust balances[5]	**2,086**	1,842	n/a
Deferred income taxes – U.S. Tax Reform[6]	**1,141**	1,170	n/a
Canadian Mainline bridging amortization account[7]	**483**	537	9
Cost of removal[8]	**254**	246	n/a
Canadian Mainline long-term adjustment account[7,9]	**186**	223	5
Deferred income taxes[1]	**139**	115	n/a
Canadian Mainline short-term adjustment and toll-stabilization accounts[7,9,10]	**60**	4	n/a
ANR post-employment and retirement benefits other than pension[11]	**40**	40	n/a
Operating and debt-service regulatory liabilities[4]	**32**	48	1
Pensions and other post-retirement benefits[2]	**13**	18	n/a
Other	**66**	58	n/a
	4,500	4,301	
Less: Current portion included in Accounts payable and other (Note 16)	**200**	153	
	4,300	4,148	

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 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.
3 Foreign exchange on long-term debt of the NGTL System represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate at the time of issue. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls.
4 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.
5 This balance represents the amounts collected in tolls from shippers and included in the LMCI restricted investments to fund future abandonment of the Company's CER-regulated pipeline facilities.
6 The regulatory liabilities will be 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 This balance represents anticipated costs of removal that have been, and continue to be, included in depreciation rates and collected in the service rates of certain rate-regulated operations for future costs to be incurred.
9 Under the terms of the 2021-2026 Mainline Settlement, $223 million is amortized over the six-year settlement term and the residual of $4 million was transferred to the STAA at December 31, 2020.
10 Under the terms of the 2021-2026 Mainline Settlement, the STAA account will commence amortization over the remainder of the six-year settlement term when predetermined thresholds per the settlement agreement are met.
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 $40 million (US$32 million) balance at December 31, 2021 is subject to resolution through future regulatory proceedings and, accordingly, a settlement period cannot be determined at this time.

13. GOODWILL

The Company has recorded the following Goodwill on its acquisitions:

(millions of Canadian $)	U.S. Natural Gas Pipelines
Balance at January 1, 2020	12,887
Foreign exchange rate changes	(208)
Balance at December 31, 2020	12,679
Foreign exchange rate changes	**(97)**
Balance at December 31, 2021	**12,582**

As part of the annual goodwill impairment assessment at December 31, 2021, the Company evaluated qualitative factors impacting the fair value of the underlying reporting units for all its reporting units other than the Columbia reporting unit. It was determined that it was more likely than not that the fair value of these reporting units exceeded their carrying amounts, including goodwill.

The Company elected to proceed directly to a quantitative annual goodwill impairment test at December 31, 2021 for the $9,303 million of goodwill related to the Columbia reporting unit following an uncontested rate case settlement with shippers in 2021. It was determined that the fair value of Columbia exceeded its carrying value, including goodwill at December 31, 2021.

Sale of Columbia Midstream Assets

In August 2019, TC Energy completed the sale of certain Columbia Midstream assets. As these assets constituted a business, and there was goodwill within this reporting unit, $595 million of Columbia's goodwill allocated to these assets was released and netted in the pre-tax gain on sale. The amount released was determined based on the relative fair values of the assets sold and the portion of the reporting unit retained. The fair value of the reporting unit was determined using a discounted cash flow analysis. Refer to Note 28, Acquisitions and dispositions, for additional details.

14. OTHER LONG-TERM ASSETS

at December 31 (millions of Canadian $)	2021	2020
Deferred income tax assets (Note 18)	**509**	177
Employee post-retirement benefits (Note 25)	**312**	207
Long-term contract assets (Note 5)	**249**	192
Keystone XL contractual recoveries (Note 6)	**50**	—
Fair value of derivative contracts (Note 26)	**48**	41
Capital projects in development[1]	**14**	231
Other	**221**	131
	1,403	979

1 Following the revocation of the Presidential Permit for the Keystone XL pipeline project on January 20, 2021, the Company recognized a pre-tax asset impairment charge of $3,126 million, of which $2,896 million was related to Keystone XL assets under construction and $230 million was related to associated capital projects in development. Refer to Note 6, Keystone XL, for additional information.

15. NOTES PAYABLE

(millions of Canadian $, unless otherwise noted)	2021 Outstanding at December 31	2021 Weighted Average Interest Rate per Annum at December 31	2020 Outstanding at December 31	2020 Weighted Average Interest Rate per Annum at December 31
Canada[1]	**4,953**	**0.4 %**	2,836	0.4 %
U.S. (2021 – US$54; 2020 – US$900)	**68**	**0.3 %**	1,149	0.4 %
Mexico (2021 – US$115; 2020 – US$150)[2]	**145**	**1.7 %**	191	1.7 %
	5,166		4,176	

1 At December 31, 2021, Notes payable consisted of Canadian dollar-denominated notes of $1,989 million (2020 – $656 million) and U.S. dollar-denominated notes of US$2,341 million (2020 – US$1,709 million).
2 The demand senior unsecured revolving credit facility for the Company's Mexico subsidiary can be drawn in either Mexican pesos or U.S. dollars, up to the total facility amount of MXN$5.0 billion or the U.S. dollar equivalent.

At December 31, 2021 and 2020, Notes payable reflects short-term borrowings in Canada by TransCanada PipeLines Limited (TCPL), in the U.S. by TransCanada PipeLine USA Ltd. (TCPL USA) and in Mexico by a wholly-owned Mexican subsidiary.

At December 31, 2021, total committed revolving and demand credit facilities were $12.4 billion (2020 – $12.4 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) Borrower	Description	Matures	2021 Total Facilities	2021 Unused Capacity[1]	2020 Total Facilities
Committed, syndicated, revolving, extendible, senior unsecured credit facilities[2]:					
TCPL	Supports TCPL's Canadian dollar commercial paper program and for general corporate purposes	December 2026	**3.0**	**1.0**	3.0
TCPL / TCPL USA / Columbia / TransCanada American Investments Ltd.	Supports TCPL's and TCPL USA's U.S. dollar commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2022	**US 4.5**	**US 2.1**	US 4.5
TCPL / TCPL USA / Columbia / TransCanada American Investments Ltd.	For general corporate purposes of the borrowers, guaranteed by TCPL	December 2024	**US 1.0**	**US 1.0**	US 1.0
Demand senior unsecured revolving credit facilities[2]:					
TCPL / TCPL USA	Supports the issuance of letters of credit and provides additional liquidity; TCPL USA facility guaranteed by TCPL	Demand	**2.1**[3]	**1.0**	2.1[3]
Mexico subsidiary	For Mexico general corporate purposes, guaranteed by TCPL	Demand	**MXN 5.0**[3]	**MXN 2.6**	MXN 5.0[3]

1 Net of commercial paper outstanding and facility draws.
2 Provisions of various 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 credit arrangements also require the Company to comply with various affirmative and negative covenants and maintain certain financial ratios. At December 31, 2021, the Company was in compliance with all debt covenants.
3 Or the U.S. dollar equivalent.

For the year ended December 31, 2021, the cost to maintain the above facilities was $17 million (2020 – $21 million; 2019 – $11 million).

16. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	2021	2020
Trade payables	**4,183**	3,057
Fair value of derivative contracts (Note 26)	**221**	72
Regulatory liabilities (Note 12)	**200**	153
Contract liabilities (Note 5)	**90**	129
Class C Interests (Note 6)	**75**	—
Other	**330**	405
	5,099	3,816

17. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	2021	2020
Operating lease obligations (Note 9)	**380**	427
Long-term contract liabilities (Note 5)	**184**	203
Employee post-retirement benefits (Note 25)	**174**	503
Asset retirement obligations	**61**	54
Fair value of derivative contracts (Note 26)	**47**	59
Other	**213**	229
	1,059	1,475

18. INCOME TAXES

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	2021	2020	2019
Current			
Canada	**29**	(54)	84
Foreign[1]	**276**	306	615
	305	252	699
Deferred			
Canada	**(327)**	(224)	(29)
Foreign	**142**	166	84
	(185)	(58)	55
Income Tax Expense	**120**	194	754

1 The 2019 current foreign income tax expense mainly relates to the sale of certain Columbia Midstream assets in August 2019. Refer to Note 28, Acquisitions and dispositions, for additional information.

Geographic Components of Income before Income Taxes

year ended December 31 (millions of Canadian $)	2021	2020	2019
Canada	**(292)**	691	1,144
Foreign	**2,458**	4,416	4,043
Income before Income Taxes	**2,166**	5,107	5,187

Reconciliation of Income Tax Expense

year ended December 31 (millions of Canadian $)	2021	2020	2019
Income before income taxes	**2,166**	5,107	5,187
Federal and provincial statutory tax rate	**23.0 %**	24.0 %	26.5 %
Expected income tax expense	**498**	1,226	1,375
Valuation allowance releases	**(8)**	(400)	(259)
Foreign income tax rate differentials	**(230)**	(258)	(180)
Income tax differential related to regulated operations	**(139)**	(228)	(159)
Income from non-controlling interests and equity investments	**(70)**	(141)	(78)
Alberta tax rate reduction	**—**	—	(32)
Non-taxable portion of capital gains	**—**	(62)	(28)
Non-deductible goodwill on the Columbia Midstream asset disposition	**—**	—	154
Impact of Mexico inflationary adjustments	**32**	7	13
Other	**37**	50	(52)
Income Tax Expense	**120**	194	754

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	2021	2020
Deferred Income Tax Assets		
Tax loss and credit carryforwards	**1,163**	1,389
Regulatory and other deferred amounts	**537**	532
Unrealized foreign exchange losses on long-term debt	**130**	154
Financial instruments	**—**	48
Other	**46**	70
	1,876	2,193
Less: Valuation allowance	**229**	243
	1,647	1,950
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment	**5,616**	6,124
Equity investments	**1,219**	1,087
Taxes on future revenue requirement	**333**	287
Other	**112**	81
	7,280	7,579
Net Deferred Income Tax Liabilities	**5,633**	5,629

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

at December 31		
(millions of Canadian $)	**2021**	**2020**
Deferred Income Tax Assets		
Other long-term assets (Note 14)	**509**	177
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**6,142**	5,806
Net Deferred Income Tax Liabilities	**5,633**	5,629

At December 31, 2021, the Company has recognized the benefit of non-capital loss carryforwards of $4,067 million (2020 – $3,671 million) for federal and provincial purposes in Canada, which expire from 2030 to 2041. The Company has not yet recognized the benefit of capital loss carryforwards of $21 million (2020 – $253 million) for federal and provincial purposes in Canada which have no expiry date. The Company also has Ontario minimum tax credits of $113 million (2020 – $106 million), which expire from 2026 to 2041.

At December 31, 2021, the Company has fully recognized the benefit of net operating loss carryforwards of US$446 million (2020 – US$849 million) for federal purposes in the U.S., which expire in 2037.

At December 31, 2021, the Company has recognized the benefit of net operating loss carryforwards of US$10 million (2020 – US$13 million) in Mexico, which expire from 2024 to 2031.

TC Energy recorded an income tax valuation allowance of $229 million and $243 million against the deferred income tax asset balances at December 31, 2021 and 2020, respectively. 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, 2021, the Company determined there was sufficient positive evidence to conclude that it is more likely than not that the net deferred tax assets will be realized.

At December 31, 2020, the Company recorded $400 million in valuation allowance releases primarily a result of the final investment decision to proceed with the construction of the Keystone XL pipeline, the sale of the Ontario natural gas-fired power plants and the sale of a 65 per cent per cent equity interest in Coastal GasLink LP. Refer to Note 28, Acquisitions and dispositions, for additional information on the sale of the Ontario natural gas-fired power plants and Coastal GasLink LP equity sale.

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, 2021 by approximately $896 million (2020 – $684 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $371 million, net of refunds, were made in 2021 (2020 – payments, net of refunds, of $252 million; 2019 – payments, net of refunds, of $713 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 $)	2021	2020	2019
Unrecognized tax benefit at beginning of year	**52**	29	19
Gross increases – tax positions in prior years	**5**	26	13
Gross decreases – tax positions in prior years	**(1)**	(2)	(1)
Gross increases – tax positions in current year	**26**	1	—
Lapse of statutes of limitations	**(2)**	(2)	(2)
Unrecognized Tax Benefit at End of Year	**80**	52	29

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, 2021 reflects $1 million interest expense (2020 – $4 million; 2019 – $4 million). At December 31, 2021, the Company had accrued $12 million in interest expense (2020 – $11 million; 2019 – $7 million). The Company incurred no penalties associated with income tax uncertainties related to Income tax expense for the years ended December 31, 2021, 2020 and 2019 and no penalties were accrued as at December 31, 2021, 2020 and 2019.

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 2013. Substantially all material U.S. federal, state and local income tax matters have been concluded for years through 2014. Substantially all material Mexico income tax matters have been concluded for years through 2013, except as further described below.

Mexico Tax Audit

In 2019, the Mexican tax authority, 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 which 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. In January 2022, the Company received the tax court's ruling on the 2013 tax return, which was in favour of the SAT. The Company believes this ruling is unreasonable and did not conform with Mexican tax regulations and will appeal this decision. In support of the Company's position, the Mexican Tax Ombudsman (the PRODECON), previously determined that this subsidiary's tax filings were appropriate.

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 tax, interest, penalties and financial charges. If the SAT continues to reassess the tax filings of this subsidiary for subsequent years on a similar basis, there is a risk of a material increase to the Company's exposure.

Based on recent discussions with the SAT, the Company believes that the areas of concern are confined to a subset of matters within these assessments. The Company will defend its position on these assessments and pursue all available legal tax remedies. Based on the Company's own judgment, as well as that of third-party advisors, management believes it is more likely than not that the Company's tax position will be sustained and no provision with respect to this matter has been recognized in the consolidated financial statements.

19. LONG-TERM DEBT

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2021 Outstanding at December 31	2021 Interest Rate[1]	2020 Outstanding at December 31	2020 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
U.S. (2021 – nil; 2020 – US$400)		**—**	**—**	510	9.9 %
Medium Term Notes					
Canadian	2022 to 2049	**12,491**	**4.2 %**	11,491	4.5 %
Senior Unsecured Notes					
U.S. (2021 – US$16,542; 2020 – US$14,292)	2022 to 2049	**20,936**	**4.8 %**	18,227	5.3 %
		33,427		30,228	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian	2024	**100**	**9.9 %**	100	9.9 %
U.S. (2021 and 2020 – US$200)	2023	**254**	**7.9 %**	255	7.9 %
Medium Term Notes					
Canadian	2025 to 2030	**504**	**7.4 %**	504	7.4 %
U.S. (2021 and 2020 – US$33)	2026	**41**	**7.5 %**	42	7.5 %
		899		901	
COLUMBIA PIPELINE GROUP, INC.					
Senior Unsecured Notes					
U.S. (2021 and 2020 – US$1,500)[2]	2025 to 2045	**1,898**	**4.9 %**	1,913	4.9 %
TC PIPELINES, LP					
Unsecured Term Loan					
U.S. (2021 – nil; 2020 – US$450)		**—**	**—**	574	1.4 %
Senior Unsecured Notes					
U.S. (2021 – US$850; 2020 – US$1,200)	2025 to 2027	**1,076**	**4.2 %**	1,530	4.4 %
		1,076		2,104	
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2021 – US$372; 2020 – US$672)	2024 to 2026	**472**	**5.3 %**	858	7.2 %
GAS TRANSMISSION NORTHWEST LLC					
Senior Unsecured Notes					
U.S. (2021 and 2020 – US$325)	2030 to 2035	**411**	**4.3 %**	415	4.3 %

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2021 Outstanding at December 31	2021 Interest Rate[1]	2020 Outstanding at December 31	2020 Interest Rate[1]
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Unsecured Loan Facility					
U.S. (2021 – nil; 2020 – US$25)	2023	**—**	**—**	32	1.3 %
Senior Unsecured Notes					
U.S. (2021 – US$250; 2020 – US$125)	2030 to 2031	**316**	**2.8 %**	159	2.8 %
		316		191	
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. (2021 – US$167; 2020 – US$198)	2028 to 2030	**211**	**7.6 %**	253	7.6 %
TUSCARORA GAS TRANSMISSION COMPANY					
Unsecured Term Loan					
U.S. (2021 – US$36; 2020 – US$23)	2024	**46**	**1.3 %**	29	2.2 %
NORTH BAJA PIPELINE, LLC					
Unsecured Term Loan					
U.S. (2021 – nil; 2020 – US$50)		**—**	**—**	64	1.2 %
		38,756		36,956	
Current portion of long-term debt		**(1,320)**		(1,972)	
Unamortized debt discount and issue costs		**(243)**		(238)	
Fair value adjustments[3]		**148**		167	
		37,341		34,913	

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 Certain subsidiaries of Columbia have guaranteed the principal payments of Columbia's senior unsecured notes. Each guarantor of Columbia's obligations is required to comply with covenants under the debt indenture and in the event of default, the guarantors would be obligated to pay the principal and related interest.

3 Related to the acquisition of Columbia.

Principal Repayments

At December 31, 2021, principal repayments for the next five years on the Company's long-term debt are approximately as follows:

(millions of Canadian $)	2022	2023	2024	2025	2026
Principal repayments on long-term debt	1,320	1,823	2,657	2,698	1,778

Long-Term Debt Issued

The Company issued long-term debt over the three years ended December 31, 2021 as follows:

(millions of Canadian $, unless otherwise noted) Company	Issue Date	Type	Maturity Date	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED					
	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 % [1]
	April 2020	Senior Unsecured Notes	April 2030	US 1,250	4.10 %
	April 2020	Medium Term Notes	April 2027	2,000	3.80 %
	September 2019	Medium Term Notes	September 2029	700	3.00 %
	September 2019	Medium Term Notes	July 2048	300	4.18 % [2]
	April 2019	Medium Term Notes	October 2049	1,000	4.34 %
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
	October 2021	Senior Unsecured Notes	October 2031	US 125	2.68 %
	October 2020	Senior Unsecured Notes	October 2030	US 125	2.84 %
TUSCARORA GAS TRANSMISSION COMPANY					
	August 2021	Unsecured Term Loan	August 2024	US 13	Floating
KEYSTONE XL SUBSIDIARIES[3]					
	Various	Project-Level Credit Facility	June 2021	US 849	Floating
COLUMBIA PIPELINE GROUP, INC.[4]					
	January 2021	Unsecured Term Loan	June 2022	US 4,040	Floating
GAS TRANSMISSION NORTHWEST LLC					
	June 2020	Senior Unsecured Notes	June 2030	US 175	3.12 %
COASTAL GASLINK PIPELINE LIMITED PARTNERSHIP[5]					
	April 2020	Senior Secured Credit Facilities	April 2027	1,603	Floating
NORTHERN COURIER PIPELINE LIMITED PARTNERSHIP[6]					
	July 2019	Senior Secured Notes	June 2042	1,000	3.365 %

1 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 4.186 per cent.
2 Reflects coupon rate on re-opening of a pre-existing MTN issue. The MTNs were issued at a premium to par, resulting in a re-issuance yield of 3.991 per cent.
3 On January 4, 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 6, Keystone XL, for additional information.
4 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.
5 In April 2020, Coastal GasLink LP entered into secured long-term project financing credit facilities. In May 2020, TC Energy completed the sale of a 65 per cent equity interest in Coastal GasLink LP and subsequently accounts for its remaining 35 per cent interest using the equity method. Immediately preceding the equity sale, Coastal GasLink LP made an initial draw of $1.6 billion on the credit facilities, of which approximately $1.5 billion was paid to TC Energy. Refer to Note 28, Acquisitions and dispositions, for additional information.
6 In July 2019, subsequent to the Senior Secured Notes issuance, TC Energy completed the sale of an 85 per cent equity interest in Northern Courier and subsequently accounted for its remaining interest using the equity method. On November 30, 2021, the Company sold its remaining 15 per cent equity interest in Northern Courier. Refer to Note 28, Acquisitions and dispositions, for additional information.

Long-Term Debt Retired/Repaid

The Company retired/repaid long-term debt over the three years ended December 31, 2021 as follows:

(millions of Canadian $, unless otherwise noted) Company	Retirement/Repayment Date	Type	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED				
	November 2021	Medium Term Notes	500	3.65 %
	January 2021	Debentures	US 400	9.875 %
	November 2020	Debentures	250	11.80 %
	October 2020	Senior Unsecured Notes	US 1,000	3.80 %
	March 2020[1]	Senior Unsecured Notes	US 750	4.60 %
	November 2019	Senior Unsecured Notes	US 700	2.125 %
	November 2019	Senior Unsecured Notes	US 550	Floating
	May 2019	Medium Term Notes	13	9.35 %
	March 2019	Debentures	100	10.50 %
	January 2019	Senior Unsecured Notes	US 750	7.125 %
	January 2019	Senior Unsecured Notes	US 400	3.125 %
COLUMBIA PIPELINE GROUP, INC.				
	December 2021	Unsecured Term Loan[2]	US 4,040	Floating
	June 2020	Senior Unsecured Notes	US 750	3.30 %
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 %
	June 2019	Unsecured Term Loan	US 50	Floating
ANR PIPELINE COMPANY				
	November 2021	Senior Unsecured Notes	US 300	9.625 %
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
	October 2020	Unsecured Loan Facility	US 99	Floating
KEYSTONE XL SUBSIDIARIES[3]				
	June 2021	Project-Level Credit Facility	US 849	Floating
GAS TRANSMISSION NORTHWEST LLC				
	June 2020	Senior Unsecured Notes	US 100	5.29 %
	May 2019	Unsecured Term Loan	US 35	Floating

1 Related unamortized debt issue costs of $8 million were included in Interest expense in the Consolidated statement of income for the year ended December 31, 2020.

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 6, Keystone XL, for additional information.

On March 4, 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 $)	2021	2020	2019
Interest on long-term debt	**1,841**	1,963	1,931
Interest on junior subordinated notes	**453**	470	427
Interest on short-term debt	**10**	46	106
Capitalized interest	**(22)**	(294)	(186)
Amortization and other financial charges[1]	**78**	43	55
	2,360	2,228	2,333

1 Amortization and other financial charges includes 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 $2,299 million in 2021 (2020 – $2,203 million; 2019 – $2,295 million) on long-term debt, junior subordinated notes and short-term debt, net of interest capitalized.

20. JUNIOR SUBORDINATED NOTES

Outstanding loan amount (millions of Canadian $, unless otherwise noted)	Maturity Date	2021 Outstanding at December 31	2021 Effective Interest Rate[1]	2020 Outstanding at December 31	2020 Effective Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
US$1,000 notes issued 2007 at 6.35%[2]	2067	**1,265**	**4.0 %**	1,275	4.1 %
US$750 notes issued 2015 at 5.875%[3,4]	2075	**949**	**5.0 %**	957	5.0 %
US$1,200 notes issued 2016 at 6.125%[3,4]	2076	**1,519**	**5.8 %**	1,530	5.8 %
US$1,500 notes issued 2017 at 5.55%[3,4]	2077	**1,899**	**4.7 %**	1,913	4.7 %
$1,500 notes issued 2017 at 4.90%[3,4]	2077	**1,500**	**4.5 %**	1,500	4.5 %
US$1,100 notes issued 2019 at 5.75%[3,4]	2079	**1,392**	**5.4 %**	1,403	5.4 %
$500 notes issued 2021 at 4.45%[3,4]	2081	**500**	**4.0 %**	—	—
		9,024		8,578	
Unamortized debt discount and issue costs		**(85)**		(80)	
		8,939		8,498	

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 billion were issued in 2007 at a fixed rate of 6.35 per cent and converted in 2017 to a floating interest rate that is reset quarterly to the three-month LIBOR plus 2.21 per cent.
3 The Junior subordinated notes were issued to TransCanada Trust, a financing trust subsidiary wholly owned by TCPL. While the obligations of TransCanada 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.

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

In March 2021, TransCanada Trust (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 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.

In September 2019, the Trust issued US$1.1 billion of Trust Notes – Series 2019-A to investors with a fixed interest rate of 5.50 per cent per annum for the first 10 years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for US$1.1 billion of junior subordinated notes of TCPL at an initial fixed rate of 5.75 per cent, including a 0.25 per cent administration charge. The rate will reset commencing September 2029 until September 2049 to the then three-month LIBOR plus 4.404 per cent per annum; from September 2049 until September 2079, the interest rate will reset to the then three-month LIBOR plus 5.154 per cent per annum. Refer to Note 3, Accounting changes, for additional information regarding the expected impact to the Company with certain rate settings of LIBOR which ceased to be published at the end of 2021 with full cessation by mid-2023. The junior subordinated notes are callable at TCPL's option at any time on or after September 15, 2029 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.

21. NON-CONTROLLING INTERESTS

TC PipeLines, LP

Acquisition

In December 2020, the Company entered into a definitive agreement and plan of merger to acquire 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. Upon close of the transaction on March 3, 2021, 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 loss	**353**
Non-controlling interests	**(1,563)**
Deferred income tax liabilities	**(443)**
Other	**(12)**

Non-controlling interests

Prior to the March 3, 2021 acquisition described above, the non-controlling interests in TC PipeLines, LP were 74.5 per cent (2020 and 2019 – 74.5 per cent). Subsequent to this acquisition, the remaining non-controlling interest on the Consolidated balance sheet is related to the Company's 61.7 per cent investment in Portland Natural Gas Transmission System (PNGTS), which is held by TC PipeLines, LP.

The Company's Net income attributable to non-controlling interests included in the Consolidated statement of income were as follows:

year ended December 31 (millions of Canadian $)	2021	2020	2019
Non-controlling interest in TC PipeLines, LP	**60**	284	270
Non-controlling interest in PNGTS	**30**	23	23
Redeemable non-controlling interest (Note 6)	**1**	(10)	—
	91	297	293

22. COMMON SHARES

	Number of Shares (thousands)	Amount (millions of Canadian $)
Outstanding at January 1, 2019	918,097	23,174
Dividend reinvestment and share purchase plan	15,165	931
Exercise of options	5,138	282
Outstanding at December 31, 2019	938,400	24,387
Exercise of options	1,664	101
Outstanding at December 31, 2020	940,064	24,488
Acquisition of TC PipeLines, LP, net of transaction costs (Note 21)	**37,955**	**2,063**
Exercise of options	**2,797**	**165**
Outstanding at December 31, 2021	**980,816**	**26,716**

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

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 21, Non-controlling interests, for additional information.

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. Commencing with the dividends declared October 31, 2019, common shares purchased with reinvested cash dividends under the Company's DRP are acquired on the open market at 100 per cent of the weighted average purchase price. From January 1, 2019 to October 31, 2019, common shares under the DRP were issued from treasury at a two per cent discount to market prices over a specified period.

TC Energy Corporation At-the-Market Equity Issuance Program

In December 2020, the Company established an At-the-Market Program (ATM Program) that allows, from time to time, for the issuance of common shares from treasury at the prevailing market price when sold through the Toronto Stock Exchange, the New York Stock Exchange or any other existing trading market for TC Energy common shares in Canada or the United States. This ATM program is effective for a 25-month period and will be utilized as appropriate to assist in managing the Company's capital structure. Under this program the Company could issue up to $1.0 billion in common shares or the U.S. dollar equivalent. No common shares were issued under this program in 2021 or 2020.

Basic and Diluted Net Income per Common Share

Net income per common share is calculated by dividing Net income 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 shares issuable under the DRP up to October 31, 2019 when participation was satisfied with common shares issued from treasury.

Weighted Average Common Shares Outstanding (millions)	**2021**	**2020**	**2019**
Basic	**973**	940	929
Diluted	**974**	940	931

Stock Options

	Number of Options (thousands)	**Weighted Average Exercise Prices**	**Weighted Average Remaining Contractual Life** (years)
Options outstanding at January 1, 2021	**8,996**	**$59.55**	
Options granted	**1,679**	**$56.86**	
Options exercised	**(2,797)**	**$53.10**	
Options forfeited/expired	**(109)**	**$59.96**	
Options Outstanding at December 31, 2021	**7,769**	**$61.29**	**4.2**
Options Exercisable at December 31, 2021	**4,410**	**$60.13**	**3.2**

At December 31, 2021, an additional 4,826,189 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 applying the following weighted average assumptions:

year ended December 31	**2021**	**2020**	**2019**
Weighted average fair value	**$7.39**	$7.73	$6.37
Expected life (years)[1]	**5.4**	5.7	5.7
Interest rate	**0.5 %**	1.5 %	1.9 %
Volatility[2]	**25 %**	17 %	19 %
Dividend yield	**6.0 %**	4.2 %	5.0 %

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 $12 million in 2021 (2020 – $12 million; 2019 – $13 million). At December 31, 2021, unrecognized compensation costs related to non-vested stock options were $13 million. The cost is expected to be fully recognized over a weighted average period of 1.8 years.

The following table summarizes additional stock option information:

year ended December 31			
(millions of Canadian $, unless otherwise noted)	**2021**	2020	2019
Total intrinsic value of options exercised	**28**	31	75
Total fair value of options that have vested	**110**	101	143
Total options vested	**1.9 million**	2.0 million	2.1 million

As at December 31, 2021, the aggregate intrinsic value of the total options exercisable was $7 million and the aggregate intrinsic value of options outstanding was $12 million.

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.

23. PREFERRED SHARES

at December 31, 2021	Number of Shares Outstanding	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] 2021	2020	2019
	(thousands)						(millions of Canadian $)		
Cumulative First Preferred Shares									
Series 1	14,577	3.479 %	$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	1.694 %	$0.4235	$25.00	June 30, 2025	Series 4	**246**	246	209
Series 4	4,003	Floating [4]	Floating	$25.00	June 30, 2025	Series 3	**97**	97	134
Series 5	12,071	1.949 % [5]	$0.48725	$25.00	January 30, 2026	Series 6	**294**	310	310
Series 6	1,929	Floating [4]	Floating	$25.00	January 30, 2026	Series 5	**48**	32	32
Series 7	24,000	3.903 %	$0.97575	$25.00	April 30, 2024	Series 8	**589**	589	589
Series 9	18,000	3.762 %	$0.9405	$25.00	October 30, 2024	Series 10	**442**	442	442
Series 11	10,000	3.351 %	$0.83775	$25.00	November 28, 2025	Series 12	**244**	244	244
Series 13	—	—	—	—	—	—	**—**	493	493
Series 15	40,000	4.90 %	$1.225	$25.00	May 31, 2022	Series 16	**988**	988	988
							3,487	3,980	3,980

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), 2.96 per cent (Series 12), or 3.85 per cent (Series 16). 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), 2.96 per cent (Series 11), or 3.85 per cent, subject to a minimum of 4.90 per cent (Series 15).

3 Net of underwriting commissions and deferred income taxes.

4 The floating quarterly dividend rate for the Series 2 preferred shares is 2.049 per cent for the period starting December 31, 2021 to, but excluding, March 31, 2022. The floating quarterly dividend rate for the Series 4 preferred shares is 1.409 per cent for the period starting December 31, 2021 to, but excluding, March 31, 2022. The floating quarterly dividend rate for the Series 6 preferred shares is 1.686 per cent for the period starting October 30, 2021 to, but excluding, January 30, 2022. These rates will reset each quarter going forward.

5 The fixed rate dividend for Series 5 preferred shares decreased from 2.263 per cent to 1.949 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, 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, as previously declared on May 6, 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.

On February 1, 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.

On June 30, 2020, 401,590 Series 3 preferred shares were converted, on a one-for-one basis, into Series 4 preferred shares and 1,865,362 Series 4 preferred shares were converted, on a one-for-one basis, into Series 3 preferred shares.

On December 31, 2019, 173,954 Series 1 preferred shares were converted, on a one-for-one basis, into Series 2 preferred shares and 5,252,715 Series 2 preferred shares were converted, on a one-for-one basis, into Series 1 preferred shares.

24. OTHER COMPREHENSIVE INCOME/(LOSS) AND ACCUMULATED OTHER COMPREHENSIVE 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, 2021			
(millions of Canadian $)	Before Tax Amount	Income Tax Recovery/(Expense)	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 and losses on cash flow hedges	**68**	**(13)**	**55**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**208**	**(50)**	**158**
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	**20**	**(6)**	**14**
Other comprehensive income on equity investments	**714**	**(179)**	**535**
Other Comprehensive Income	**894**	**(252)**	**642**

year ended December 31, 2020			
(millions of Canadian $)	Before Tax Amount	Income Tax Recovery/(Expense)	Net of Tax Amount
Foreign currency translation gains and losses on net investment in foreign operations	(647)	38	(609)
Change in fair value of net investment hedges	48	(12)	36
Change in fair value of cash flow hedges	(771)	188	(583)
Reclassification to net income of gains and losses on cash flow hedges	649	(160)	489
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	15	(3)	12
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	23	(6)	17
Other comprehensive loss on equity investments	(373)	93	(280)
Other Comprehensive Loss	(1,056)	138	(918)

year ended December 31, 2019			
(millions of Canadian $)	Before Tax Amount	Income Tax Recovery/(Expense)	Net of Tax Amount
Foreign currency translation gains and losses on net investment in foreign operations	(914)	(30)	(944)
Reclassification of foreign currency translation gains on disposal of foreign operations	(13)	—	(13)
Change in fair value of net investment hedges	46	(11)	35
Change in fair value of cash flow hedges	(78)	16	(62)
Reclassification to net income of gains and losses on cash flow hedges	19	(5)	14
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	(15)	5	(10)
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	14	(4)	10
Other comprehensive loss on equity investments	(114)	32	(82)
Other Comprehensive Loss	(1,055)	3	(1,052)

The changes in AOCI by component were as follows:

(millions of Canadian $)	Currency Translation Adjustments	Cash Flow Hedges	Pension and Other Post-Retirement Benefit Plan Adjustments	Equity Investments	Total[1]
AOCI balance at January 1, 2019	107	(23)	(314)	(376)	(606)
Other comprehensive loss before reclassifications[2]	(824)	(49)	(10)	(86)	(969)
Amounts reclassified from AOCI	(13)	14	10	5	16
Net current period other comprehensive loss	(837)	(35)	—	(81)	(953)
AOCI balance at December 31, 2019	(730)	(58)	(314)	(457)	(1,559)
Other comprehensive (loss)/income before reclassifications[2]	(543)	(567)	12	(292)	(1,390)
Amounts reclassified from AOCI	—	482	17	11	510
Net current period other comprehensive (loss)/income	(543)	(85)	29	(281)	(880)
AOCI balance at December 31, 2020	(1,273)	(143)	(285)	(738)	(2,439)
Other comprehensive (loss)/income before reclassifications[2]	**(98)**	**(11)**	**158**	**506**	**555**
Amounts reclassified from AOCI[3]	**—**	**55**	**14**	**28**	**97**
Net current period other comprehensive (loss)/income	**(98)**	**44**	**172**	**534**	**652**
Acquisition of TC PipeLines, LP[4]	**362**	**(13)**	**—**	**4**	**353**
AOCI balance at December 31, 2021	**(1,009)**	**(112)**	**(113)**	**(200)**	**(1,434)**

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.
2 Other comprehensive (loss)/income before reclassifications on currency translation adjustments, cash flow hedges and equity investments are net of non-controlling interest losses of $12 million (2020 – losses of $30 million; 2019 – losses of $85 million), gains of $1 million (2020 – losses of $16 million; 2019 – losses of $13 million), and gains of $1 million (2020 – gains of $1 million; 2019 – losses of $1 million), respectively.
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 $62 million ($47 million, net of tax) at December 31, 2021. 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 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 21, 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 $)	**2021**	2020	2019	**Affected Line Item in the Consolidated Statement of Income**[1]
Cash flow hedges				
Commodities	**(22)**	(1)	(7)	Revenues (Power and Storage)
Interest rate	**(46)**	(28)	(12)	Interest expense
Interest rate	**—**	(613)	—	Net gain/(loss) on assets sold/held for sale[2]
	(68)	(642)	(19)	Total before tax
	13	160	5	Income tax expense[2]
	(55)	(482)	(14)	Net of tax[3]
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial losses	**(22)**	(23)	(14)	Plant operating costs and other[4]
Settlement gain	**2**	—	—	Plant operating costs and other[4]
	(20)	(23)	(14)	Total before tax
	6	6	4	Income tax expense
	(14)	(17)	(10)	Net of tax
Equity investments				
Equity income	**(37)**	(15)	(8)	Income from equity investments
	9	4	3	Income tax expense
	(28)	(11)	(5)	Net of tax[3]
Currency translation adjustments				
Foreign currency translation gains on disposal of foreign operations	**—**	—	13	Net gain/(loss) on assets sold/held for sale
	—	—	—	Income tax expense
	—	—	13	Net of tax

1 Amounts in parentheses indicate expenses to the Consolidated statement of income.

2 Represents a loss of $613 million ($459 million, net of tax) related to a contractually required derivative instrument used to hedge the interest rate risk associated with project-level financing of the Coastal GasLink construction. The derivative instrument was derecognized as part of the sale of a 65 per cent equity interest in Coastal GasLink LP. Refer to Note 28, Acquisitions and dispositions, for additional information.

3 Amounts reclassified from AOCI on cash flow hedges are net of non-controlling interest of nil (2020 – losses of $7 million; 2019 – nil).

4 These AOCI components are included in the computation of net benefit cost. Refer to Note 25, Employee post-retirement benefits, for additional information.

25. EMPLOYEE POST-RETIREMENT BENEFITS

The Company sponsors DB Plans for certain of its employees. Pension benefits provided under the DB Plans are generally based on years of service and highest average earnings over three consecutive years of employment. Effective January 1, 2019, there were certain amendments made to the Canadian DB Plan for new members whereby, subsequent to that date, 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. 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 is approximately ten years at December 31, 2021 (2020 and 2019 – nine 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 11 years at December 31, 2021 (2020 and 2019 – 11 years). In 2021, the Company expensed $58 million (2020 – $58 million; 2019 – $61 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 $)	2021	2020	2019
DB Plans	**105**	124	122
Other post-retirement benefit plans	**8**	9	22
Savings and DC Plans	**58**	58	61
	171	191	205

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. As such, in addition to the cash contributions noted above, the Company provided a $20 million letter of credit to the Canadian DB Plan in 2021 (2020 – $13 million; 2019 – $12 million), resulting in a total of $322 million provided to the Canadian DB Plan under letters of credit at December 31, 2021.

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2021 and the next required valuation will be as at January 1, 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, a settlement and curtailment occurred for the U.S. DB Plan in December 2021. The impact of these amounts were 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.

Employee participation in the VRP also resulted in a curtailment in the U.S. other post-retirement benefits plan (OPEB) in December 2021. The curtailment loss decreased the Plan's unrealized actuarial gain by $3 million which was included in OCI and increased the OPEB obligation by $3 million, resulting in no adjustment to net benefit cost in 2021.

The Company's funded status at December 31 was comprised of the following:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2021**	2020	**2021**	2020
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**4,326**	4,058	**457**	427
Service cost	**171**	155	**6**	6
Interest cost	**119**	133	**12**	14
Employee contributions	**6**	6	**1**	—
Benefits paid	**(372)**	(249)	**(21)**	(21)
Actuarial (gain)/loss	**(208)**	242	**(35)**	36
Curtailment	**(5)**	—	**3**	—
Foreign exchange rate changes	**(10)**	(19)	**(4)**	(5)
Benefit obligation – end of year	**4,027**	4,326	**419**	457
Change in Plan Assets				
Plan assets at fair value – beginning of year	**4,038**	3,693	**441**	406
Actual return on plan assets	**376**	485	**5**	56
Employer contributions[2]	**105**	124	**8**	9
Employee contributions	**6**	6	**1**	—
Benefits paid	**(372)**	(249)	**(21)**	(21)
Foreign exchange rate changes	**(8)**	(21)	**(3)**	(9)
Plan assets at fair value – end of year	**4,145**	4,038	**431**	441
Funded Status – Plan Surplus/(Deficit)	**118**	(288)	**12**	(16)

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 Excludes a $20 million letter of credit provided to the Canadian DB Plan for funding purposes (2020 – $13 million).

The actuarial gain realized on the defined benefit plan obligation is primarily attributable to an increase in the weighted average discount rate from 2.70 per cent in 2020 to 3.05 per cent in 2021.

The actuarial gain realized on the other post-retirement benefit plan obligation is primarily due to the increase in the weighted average discount rate from 2.75 per cent in 2020 to 3.10 per cent in 2021.

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 $)	**2021**	2020	**2021**	2020
Other long-term assets (Note 14)	**119**	29	**193**	178
Accounts payable and other	**—**	—	**(8)**	(8)
Other long-term liabilities (Note 17)	**(1)**	(317)	**(173)**	(186)
	118	(288)	**12**	(16)

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 $)	**2021**	2020	**2021**	2020
Projected benefit obligation[1]	**(2,687)**	(3,292)	**(183)**	(194)
Plan assets at fair value	**2,686**	2,975	**—**	—
Funded Status – Plan Deficit	**(1)**	(317)	**(183)**	(194)

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 $)	**2021**	2020
Accumulated benefit obligation	**(3,714)**	(3,957)
Plan assets at fair value	**4,145**	4,038
Funded Status – Plan Surplus	**431**	81

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, 2021 and December 31, 2020.

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
	2021	2020	**2021**
Debt securities	**34 %**	33 %	**25% to 45%**
Equity securities	**53 %**	57 %	**35% to 65%**
Alternatives	**13 %**	10 %	**10% to 20%**
	100 %	100 %	

Debt and equity securities include the Company's debt and common shares as follows:

at December 31			Percentage of Plan Assets	
(millions of Canadian $)	**2021**	2020	**2021**	2020
Debt securities	**7**	13	**0.2 %**	0.3 %
Equity securities	**5**	5	**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 the use of leveraged derivatives is prohibited.

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 other post-retirement benefits measured at fair value, which have been categorized into the three categories based on a fair value hierarchy. For additional information on the fair value hierarchy, refer to Note 26, Risk management and financial instruments.

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 $)	**2021**	**2020**	**2021**	**2020**	**2021**	**2020**	**2021**	**2020**	**2021**	**2020**
Asset Category										
Cash and Cash Equivalents	**68**	87	**2**	—	**—**	—	**70**	87	**2**	2
Equity Securities:										
Canadian	**269**	276	**148**	177	**—**	—	**417**	453	**9**	10
U.S.	**649**	594	**164**	211	**—**	—	**813**	805	**18**	18
International	**126**	114	**354**	380	**—**	—	**480**	494	**10**	11
Global	**111**	116	**313**	368	**—**	—	**424**	484	**9**	11
Emerging	**25**	35	**120**	125	**—**	—	**145**	160	**3**	4
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**226**	207	**—**	—	**226**	207	**5**	5
Provincial	**—**	—	**331**	283	**—**	—	**331**	283	**7**	6
Municipal	**—**	—	**16**	13	**—**	—	**16**	13	**—**	—
Corporate	**—**	—	**147**	151	**—**	—	**147**	151	**4**	3
U.S. Bonds:										
Federal	**433**	444	**15**	14	**—**	—	**448**	458	**10**	10
Municipal	**—**	—	**1**	2	**—**	—	**1**	2	**—**	—
Corporate	**67**	72	**143**	143	**—**	—	**210**	215	**5**	5
International:										
Government	**6**	8	**7**	6	**—**	—	**13**	14	**—**	—
Corporate	**—**	—	**73**	48	**—**	—	**73**	48	**2**	1
Mortgage backed	**42**	47	**5**	4	**—**	—	**47**	51	**1**	1
Other Investments:										
Real estate	**—**	—	**—**	—	**283**	213	**283**	213	**6**	5
Infrastructure	**—**	—	**—**	—	**281**	203	**281**	203	**6**	5
Private equity funds	**—**	—	**—**	—	**1**	1	**1**	1	**—**	—
Derivatives	**—**	—	**—**	(8)	**—**	—	**—**	(8)	**—**	—
Funds held on deposit	**150**	145	**—**	—	**—**	—	**150**	145	**3**	3
	1,946	1,938	**2,065**	2,124	**565**	417	**4,576**	4,479	**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, 2019	379
Purchases and sales	42
Realized and unrealized losses	(4)
Balance at December 31, 2020	417
Purchases and sales	**100**
Realized and unrealized gains	**48**
Balance at December 31, 2021	**565**

The Company's expected funding contributions in 2022 are approximately $76 million for the DB Plans, approximately $7 million for the other post-retirement benefit plans and approximately $55 million for the savings plans and DC Plans. The Company expects to provide an additional estimated $20 million letter of credit to the Canadian DB Plan for the funding of solvency requirements.

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

(millions of Canadian $)	Pension Benefits	Other Post-Retirement Benefits
2022	208	25
2023	211	25
2024	216	24
2025	220	24
2026	224	24
2027 to 2031	1,171	114

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, 2021. 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	
	2021	2020	2021	2020
Discount rate	**3.05 %**	2.70 %	**3.10 %**	2.75 %
Rate of compensation increase	**2.95 %**	2.60 %	**—**	—

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		
	2021	2020	2019	2021	2020	2019
Discount rate	**2.70 %**	3.20 %	3.90 %	**2.80 %**	3.35 %	4.10 %
Expected long-term rate of return on plan assets	**6.15 %**	6.40 %	6.60 %	**3.00 %**	3.50 %	4.30 %
Rate of compensation increase	**2.60 %**	3.00 %	3.00 %	—	—	—

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and estimating future levels and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets 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 5.60 per cent weighted-average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2022 measurement purposes. The rate was assumed to decrease gradually to 5.00 per cent by 2029 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 $)	**2021**	2020	2019	**2021**	2020	2019
Service cost[1]	**171**	155	126	**6**	6	5
Other components of net benefit cost[1]						
Interest cost	**119**	133	142	**12**	14	17
Expected return on plan assets	**(234)**	(230)	(222)	**(13)**	(14)	(15)
Amortization of actuarial loss	**23**	21	12	**2**	2	2
Amortization of regulatory asset	**27**	25	14	**2**	2	2
Curtailment gain	**(5)**	—	—	**—**	—	—
Settlement gain – AOCI	**(2)**	—	—	**—**	—	—
	(72)	(51)	(54)	**3**	4	6
Net Benefit Cost Recognized	**99**	104	72	**9**	10	11

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	2021		2020		2019	
(millions of Canadian $)	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Net loss	**147**	**5**	358	22	398	20

Pre-tax amounts recognized in OCI were as follows:

at December 31	2021		2020		2019	
(millions of Canadian $)	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Amortization of net loss from AOCI to net income	**(23)**	**(2)**	(21)	(2)	(12)	(2)
Curtailment	**—**	**3**	—	—	—	—
Settlement	**2**	**—**	—	—	—	—
Funded status adjustment	**(190)**	**(18)**	(18)	3	52	(37)
	(211)	**(17)**	(39)	1	40	(39)

26. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TC Energy has exposure to market risk and counterparty credit risk, 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. Market risk and counterparty credit risk are managed within limits that are established by the Company's Board of Directors, implemented by senior management and monitored by the Company's risk management, internal audit and business segment groups. The Board of Directors' Audit Committee oversees how management monitors compliance with market risk and counterparty credit 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 supply of 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.

Climate change also presents a potential financial impact to commodity prices and volumes. TC Energy's exposure to climate change risk 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. In addition, scenario planning against several demand outlooks and monitoring of key signposts is also considered as part of the Company's long-term corporate strategic planning process.

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.

Many of TC Energy's financial instruments and contractual obligations with variable rate components reference U.S. dollar LIBOR, of which certain rate settings have ceased to be published at the end of 2021 with full cessation by mid-2023. Refer to Note 3, Accounting changes, for additional information on Reference Rate Reform.

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 small portion of the Company's Mexico Natural Gas Pipelines monetary assets and liabilities are peso-denominated, while the functional currency for our Mexico operations is 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. This exposure is managed using foreign exchange derivatives.

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, foreign exchange forwards 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	2021		2020	
(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 2022 to 2023)	**(4)**	**US 3,800**	45	US 2,200
U.S. dollar cross-currency interest rate swaps (maturing 2022 to 2025)[3]	**23**	**US 400**	23	US 400
	19	**US 4,200**	68	US 2,600

1 Fair value equals carrying value.
2 No amounts have been excluded from the assessment of hedge effectiveness.
3 In 2021, Net income includes net realized gains of $1 million (2020 – 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)	2021	2020
Notional amount	**30,700 (US 24,200)**	27,700 (US 21,800)
Fair value	**35,500 (US 28,100)**	33,800 (US 26,500)

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 and loans receivable.

The sustained impact of the COVID-19 pandemic and related global energy demand and supply disruption continues to contribute to market uncertainty impacting a number of TC Energy's customers. While the majority of the Company's credit exposure is to large creditworthy entities, TC Energy has increased its monitoring and communication with those counterparties experiencing greater financial pressures.

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
- competitive position of the Company's assets and the demand for the Company's services and
- 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 supportable forecasts to determine any impairment, which is recognized in Plant operating costs and other. At December 31, 2021 and 2020, there were no significant credit losses, no significant credit risk concentrations and no significant amounts past due or impaired.

TC Energy has significant credit and performance exposure to financial institutions because they 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.

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, Loans receivable from affiliates, Other current assets, Long-term loans receivable from affiliates, Restricted investments, Other long-term assets, Notes payable, Accounts payable and other, Dividends payable, Accrued interest and Other long-term liabilities have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. 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.

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	**2021**		**2020**	
(millions of Canadian $)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt, including current portion (Note 19)	**(38,661)**	**(45,615)**	(36,885)	(46,054)
Junior subordinated notes (Note 20)	**(8,939)**	**(9,236)**	(8,498)	(8,908)
	(47,600)	**(54,851)**	(45,383)	(54,962)

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	2021		2020	
(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	**—**	**26**	—	17
Maturing within 1-5 years	**8**	**107**	—	66
Maturing within 5-10 years	**1,150**	**—**	985	—
Maturing after 10 years	**84**	**—**	85	—
Fair value of equity securities[2,4]	**817**	**—**	736	—
	2,059	**133**	1,806	83

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	2021		2020		2019	
(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)	**45**	**(2)**	130	1	32	3
Net realized gains[3]	**3**	**—**	20	1	60	—

1 Gains 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 as regulatory assets.
2 Gains and losses on other restricted investments are included in Interest income and other in the Company's Consolidated statement of income.
3 Realized gains and losses on the sale of LMCI restricted investments are determined using the average cost basis.

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 recovered or refunded 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 ratepayers 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, 2021 (millions of Canadian $)	Cash Flow Hedges	Net Investment Hedges	Held for Trading	Total Fair Value of Derivative Instruments[1]
Other current assets (Note 7)				
Commodities[2]	—	—	122	122
Foreign exchange	—	10	37	47
	—	10	159	169
Other long-term assets (Note 14)				
Commodities[2]	—	—	8	8
Foreign exchange	—	32	6	38
Interest rate[3]	2	—	—	2
	2	32	14	48
Total Derivative Assets	2	42	173	217
Accounts payable and other (Note 16)				
Commodities[2]	(23)	—	(138)	(161)
Foreign exchange	—	(4)	(46)	(50)
Interest rate[3]	(10)	—	—	(10)
	(33)	(4)	(184)	(221)
Other long-term liabilities (Note 17)				
Commodities[2]	(4)	—	(6)	(10)
Foreign exchange	—	(19)	(10)	(29)
Interest rate[3]	(8)	—	—	(8)
	(12)	(19)	(16)	(47)
Total Derivative Liabilities	(45)	(23)	(200)	(268)
Total Derivatives	(43)	19	(27)	(51)

1 Fair value equals carrying value.
2 Includes purchases and sales of power, natural gas and liquids.
3 For the year ended December 31, 2021, a $10 million payment to settle a loss on financial instruments was included in Net cash (used in)/provided by financing activities in the Consolidated statement of cash flows.

The balance sheet classification of the fair value of derivative instruments was as follows:

at December 31, 2020 (millions of Canadian $)	Cash Flow Hedges	Net Investment Hedges	Held for Trading	Total Fair Value of Derivative Instruments[1]
Other current assets (Note 7)				
Commodities[2]	—	—	13	13
Foreign exchange	—	47	175	222
	—	47	188	235
Other long-term assets (Note 14)				
Foreign exchange	—	22	19	41
	—	22	19	41
Total Derivative Assets	—	69	207	276
Accounts payable and other (Note 16)				
Commodities[2]	(8)	—	(32)	(40)
Foreign exchange	—	(1)	(10)	(11)
Interest rate[3]	(21)	—	—	(21)
	(29)	(1)	(42)	(72)
Other long-term liabilities (Note 17)				
Commodities[2]	(6)	—	(4)	(10)
Interest rate[3]	(49)	—	—	(49)
	(55)	—	(4)	(59)
Total Derivative Liabilities	(84)	(1)	(46)	(131)
Total Derivatives	(84)	68	161	145

1 Fair value equals carrying value.
2 Includes purchases and sales of power, natural gas and liquids.
3 For the year ended December 31, 2020, a $130 million payment to settle a loss on financial instruments was included in Net cash (used in)/provided by financing activities in the Consolidated statement of cash flows.

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.

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, 2021	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Purchases[1]	**553**	**104**	**34**	**—**	**—**
Sales[1]	**1,043**	**52**	**38**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**6,636**	**650**
Millions of Mexican pesos	**—**	**—**	**—**	**5,500**	**—**
Maturity dates	**2022-2026**	**2022-2027**	**2022**	**2022-2026**	**2024-2026**

1 Volumes for power, natural gas and liquids derivatives are in GWh, Bcf and MMBbls, respectively.

at December 31, 2020	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Purchases[1]	185	13	26	—	—
Sales[1]	1,786	14	30	—	—
Millions of U.S. dollars	—	—	—	4,432	1,100
Millions of Mexican pesos	—	—	—	1,700	—
Maturity dates	2021-2025	2021-2027	2021	2021-2022	2022-2026

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 $)	2021	2020	2019
Derivative instruments held for trading[1]			
Amount of unrealized gains/(losses) in the year			
Commodities	**9**	(23)	(111)
Foreign exchange	**(203)**	126	245
Amount of realized gains/(losses) in the year			
Commodities	**287**	183	378
Foreign exchange	**240**	(33)	(70)
Derivative instruments in hedging relationships[2]			
Amount of realized (losses)/gains in the year			
Commodities	**(44)**	6	(6)
Interest rate	**(32)**	(16)	2

1 Realized and unrealized gains and 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 and losses on foreign exchange held-for-trading derivative instruments are included on a net basis in Interest income and other.

2 In 2021, 2020 and 2019, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

Derivatives in cash flow hedging relationships

The components of OCI (Note 24) 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)	2021	2020	2019
Change in fair value of derivative instruments recognized in OCI[1]			
Commodities	**(35)**	(5)	(15)
Interest rate	**22**	(766)	(63)
	(13)	(771)	(78)

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI and AOCI.

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 $)	2021	2020	2019
Fair Value Hedges			
Interest rate contracts[1]			
Hedged items	—	(3)	(19)
Derivatives designated as hedging instruments	—	1	1
Cash Flow Hedges			
Reclassification of losses on derivative instruments from AOCI to net income[2,3]			
Interest rate contracts[1]	**(46)**	(648)	(12)
Commodity contracts[4]	**(22)**	(1)	(7)

1 Presented within Interest expense in the Consolidated statement of income, except for a loss of $613 million recorded in May 2020 related to a contractually required derivative instrument used to hedge the interest rate risk associated with project-level financing for the Coastal GasLink construction. This derivative instrument was derecognized as part of the sale of a 65 per cent equity interest in Coastal GasLink LP. The loss was included in Net gain/(loss) on assets sold/held for sale. Refer to Note 28, Acquisitions and dispositions, for additional information.

2 Refer to Note 24, Other comprehensive income/(loss) and accumulated other comprehensive 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 Storage) 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, 2021 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative instrument assets			
Commodities	**130**	**(91)**	**39**
Foreign exchange	**85**	**(54)**	**31**
Interest rate	**2**	**(1)**	**1**
	217	**(146)**	**71**
Derivative instrument liabilities			
Commodities	**(171)**	**91**	**(80)**
Foreign exchange	**(79)**	**54**	**(25)**
Interest rate	**(18)**	**1**	**(17)**
	(268)	**146**	**(122)**

1 Amounts available for offset do not include cash collateral pledged or received.

at December 31, 2020 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative instrument assets			
Commodities	13	(7)	6
Foreign exchange	263	(11)	252
	276	(18)	258
Derivative instrument liabilities			
Commodities	(50)	7	(43)
Foreign exchange	(11)	11	—
Interest rate	(70)	—	(70)
	(131)	18	(113)

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 $144 million and letters of credit of $130 million at December 31, 2021 (2020 – $54 million and $15 million, respectively) to its counterparties. At December 31, 2021, the Company held no cash collateral and a $6 million balance in letters of credit (2020 – nil and nil, 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, 2021, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $5 million (2020 – $4 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, 2021, 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 mainly includes long-dated commodity transactions in certain markets where liquidity is low and the Company uses the most observable inputs available or, if not available, long-term broker quotes to estimate the fair value for these transactions. 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, 2021 (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	**39**	**91**	**—**	**130**
Foreign exchange	**—**	**85**	**—**	**85**
Interest rate	**—**	**2**	**—**	**2**
Derivative instrument liabilities				
Commodities	**(49)**	**(116)**	**(6)**	**(171)**
Foreign exchange	**—**	**(79)**	**—**	**(79)**
Interest rate	**—**	**(18)**	**—**	**(18)**
	(10)	**(35)**	**(6)**	**(51)**

1 There were no transfers from Level II to Level III for the year ended December 31, 2021.

at December 31, 2020				
(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	3	10	—	13
Foreign exchange	—	263	—	263
Derivative instrument liabilities				
Commodities	(15)	(31)	(4)	(50)
Foreign exchange	—	(11)	—	(11)
Interest rate	—	(70)	—	(70)
	(12)	161	(4)	145

1 There were no transfers from Level II to Level III for the year ended December 31, 2020.

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)	2021	2020
Balance at beginning of year	**(4)**	(7)
Total (losses)/gains included in Net income	**(3)**	3
Settlements	**1**	—
Balance at end of year[1]	**(6)**	(4)

1 Revenues include unrealized losses of $3 million attributed to derivatives in the Level III category that were still held at December 31, 2021 (2020 – unrealized gains of $3 million).

27. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31			
(millions of Canadian $)	2021	2020	2019
(Increase)/decrease in Accounts receivable	**(925)**	129	31
Increase in Inventories	**(93)**	(55)	(42)
Increase in Other current assets	**(141)**	(221)	(15)
Increase/(decrease) in Accounts payable and other	**890**	(162)	352
Decrease in Accrued interest	**(18)**	(18)	(33)
(Increase)/Decrease in Operating Working Capital	**(287)**	(327)	293

28. ACQUISITIONS AND DISPOSITIONS

Canadian Natural Gas Pipelines

Coastal GasLink LP

In May 2020, TC Energy completed the sale of a 65 per cent equity interest in Coastal GasLink LP to third parties for net proceeds of $656 million before post-closing adjustments resulting in a pre-tax gain of $364 million ($402 million after tax). The pre-tax gain included $231 million related to the required remeasurement of the Company's retained 35 per cent equity interest to fair value which was based on the proceeds realized for the 65 per cent equity interest, and also incorporated the reclassification from AOCI to income of the fair value of a derivative instrument used to hedge the interest rate risk associated with project-level financing for the Coastal GasLink construction. The $402 million after-tax gain also reflected the utilization of previously unrecognized tax loss benefits. The pre-tax gain was included in Net gain/(loss) on assets sold/held for sale in the Consolidated statement of income. As part of this transaction, TC Energy was contracted by Coastal GasLink LP to construct and operate the pipeline. TC Energy uses the equity method to account for its remaining 35 per cent equity interest in the Company's consolidated financial statements.

Immediately preceding the equity sale, Coastal GasLink LP drew down $1.6 billion on the secured long-term project financing credit facilities, of which approximately $1.5 billion was paid to TC Energy.

U.S. Natural Gas Pipelines

Columbia Midstream Assets

In August 2019, TC Energy completed the sale of certain Columbia Midstream assets to a third party for approximately US$1.3 billion before post-closing adjustments.

The Company recorded a pre-tax gain on sale of $21 million ($152 million after-tax loss) including the impact of $4 million of foreign currency translation gains that were reclassified from AOCI to net income and the release of $595 million of Columbia goodwill allocated to these assets that was not deductible for income tax purposes. The pre-tax gain was included in Net gain/(loss) on assets sold/held for sale in the Consolidated statement of income. This sale did not include any interest in Columbia Energy Ventures Company, the Company's minerals business in the Appalachian basin.

In 2020, upon finalizing its 2019 annual tax returns for its U.S. operations, the Company recorded an $18 million income tax recovery related to the sale.

Columbia Pipeline Group, Inc.

At the time of the July 2016 acquisition of Columbia, certain Columbia shareholders dissented from the transaction and did not tender their shares. In October 2019, TC Energy made a payment to the dissenting Columbia shareholders in the amount of $373 million (US$284 million), representing the appraised value of their shares pursuant to a court decision, which affirmed the original Columbia share purchase price of US$25.50 per share plus accrued interest.

Liquids Pipelines

Northern Courier

In July 2019, TC Energy completed the sale of an 85 per cent equity interest in Northern Courier pipeline to a third party for gross proceeds of $144 million before post-closing adjustments resulting in a pre-tax gain of $69 million after recording the Company's remaining 15 per cent interest at fair value. The pre-tax gain was included in Net gain/(loss) on assets sold/held for sale in the Consolidated statement of income. On an after-tax basis, the gain of $115 million reflected the utilization of previously unrecognized tax loss benefits. Preceding the equity sale, Northern Courier pipeline issued $1.0 billion of long-term, non-recourse debt with all proceeds paid to TC Energy.

On November 30, 2021, TC Energy completed the sale of its remaining 15 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 assets sold/held for sale in the Consolidated statement of income.

Power and Storage

TransCanada Turbines Ltd.

In November 2020, TC Energy acquired the remaining 50 per cent ownership interest in TransCanada Turbines Ltd. (TC Turbines) for cash consideration of US$67 million. TC Turbines provides industrial gas turbine maintenance, parts, repair and overhaul services. The acquisition was accounted for as a business combination and the evaluation of assigned fair value of acquired assets and liabilities did not result in recognition of goodwill. TC Energy previously accounted for its 50 per cent interest in TC Turbines as an equity investment but commenced full consolidation of TC Turbines as of the date of acquisition, which did not have a material impact on Revenues and Net income of the Company. In addition, the pro forma incremental impact on the Company's Revenues and Net income for each of the periods presented was not material.

Ontario Natural Gas-fired Power Plants

In April 2020, the Company completed the sale of the Halton Hills and Napanee power plants as well as its 50 per cent interest in Portlands Energy Centre to a subsidiary of Ontario Power Generation Inc. for net proceeds of approximately $2.8 billion before post-closing adjustments. The total pre-tax loss of $676 million ($470 million after tax) on this transaction included losses accrued during 2019 while classified as an asset held for sale and a 2021 post-close adjustment and also reflected utilization of previously unrecognized tax loss benefits. The pre-tax loss was included in Net gain/(loss)on assets sold/held for sale for sale in the Consolidated statement of income. This loss may be amended in the future upon the settlement of existing insurance claims.

Coolidge Generating Station

In May 2019, the Company completed the sale of its Coolidge generating station in Arizona to Salt River Project Agriculture Improvement and Power District (SRP), the PPA counterparty, as per the terms of SRP's contractual right of first refusal, for proceeds of US$448 million before post-closing adjustments. As a result, the Company recorded a pre-tax gain on sale of $68 million ($54 million after tax) including the impact of $9 million of foreign currency translation gains which were reclassified from AOCI to net income. The pre-tax gain was included in Net gain/(loss) on assets sold/held for sale in the Consolidated statement of income.

29. 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 2021 were $239 million (2020 – $224 million; 2019 – $236 million).

The Company has entered into PPAs with solar and wind-power generating facilities ranging from eight to 15 years, that require the purchase of 100 per cent of the generated energy and associated environmental attributes. Future payments cannot be reasonably estimated as they are dependent on the amount of energy generated.

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, 2021, TC Energy had the following capital expenditure commitments:

- approximately $1.5 billion for its Canadian natural gas pipelines, primarily related to construction costs associated with NGTL System expansion projects
- approximately $0.1 billion for its U.S. natural gas pipelines, primarily related to construction costs associated with ANR and Columbia Gas pipeline projects
- approximately $0.1 billion for its Mexico natural gas pipelines, primarily related to construction of the Tula and Villa de Reyes pipelines
- approximately $0.1 billion for its Liquids pipelines, primarily related to capital projects in the U.S. Gulf Coast
- approximately $0.1 billion for its Power and Storage business, primarily related to the Company's proportionate share of commitments for Bruce Power's life extension program.

Contingencies

TC Energy is subject to laws and regulations governing environmental quality and pollution control. As at December 31, 2021, the Company had accrued approximately $30 million (2020 – $24 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. It is the opinion of management that the ultimate resolution of such proceedings and actions, excluding the legal proceeding related to Keystone XL described below, will not have a material impact on the Company's consolidated financial position or results of operations.

On November 22, 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. The Company will be seeking to recover more than US$15 billion in damages as a result of the U.S. Government's breach of its NAFTA obligations. This claim is in a preliminary stage and the timing of outcome is unknown at present.

Guarantees

On November 30, 2021, TC Energy completed the sale of its remaining 15 per cent equity interest in the Northern Courier pipeline and subsequently released all associated guarantees. Refer to Note 28, Acquisitions and dispositions, for additional information. As part of its role as operator of the Northern Courier pipeline prior to the sale, TC Energy had guaranteed the financial performance of the pipeline related to delivery and terminalling of bitumen and diluent and contingent financial obligations under sub-lease agreements.

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.

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		**2021**		**2020**	
(millions of Canadian $)	**Term**	**Potential Exposure**[1]	**Carrying Value**	**Potential Exposure**[1]	**Carrying Value**
Sur de Texas	to 2043	**93**	**—**	100	—
Bruce Power	to 2023	**88**	**—**	88	—
Other jointly-owned entities	to 2043	**80**	**4**	78	4
Northern Courier pipeline[2]		**—**	**—**	300	26
		261	**4**	566	30

1 TC Energy's share of the potential estimated current or contingent exposure.
2 On November 30, 2021, TC Energy completed the sale of its remaining 15 per cent equity interest in the Northern Courier pipeline and subsequently released all associated guarantees. Refer to Note 28, Acquisitions and dispositions, for additional information.

30. 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.

In the normal course of business, the Company consolidates VIEs in which it has a variable interest and for which it is considered to be the primary beneficiary. VIEs in which the Company has a variable interest but is not the primary beneficiary are considered non-consolidated VIEs and are accounted for as equity investments.

Consolidated VIEs

The Company's consolidated VIEs consist of legal entities where the Company is 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.

A significant portion of the Company's assets are held through VIEs in which the Company holds a 100 per cent voting interest, the VIE meets the definition of a business and the VIE's assets can be used for general corporate purposes. The consolidated VIEs whose assets cannot be used for purposes other than for the settlement of the VIE's obligations, or are not considered a business, were as follows:

at December 31 (millions of Canadian $)	**2021**	**2020**
ASSETS		
Current Assets		
Cash and cash equivalents	**72**	254
Accounts receivable	**70**	61
Inventories	**28**	26
Other current assets	**13**	11
	183	352
Plant, Property and Equipment	**3,672**	3,325
Equity Investments	**890**	714
Goodwill	**421**	424
Other Long-Term Assets	**—**	8
	5,166	4,823
LIABILITIES		
Current Liabilities		
Accounts payable and other	**232**	109
Redeemable non-controlling interest	**—**	633
Accrued interest	**17**	21
Current portion of long-term debt	**29**	579
	278	1,342
Regulatory Liabilities	**66**	60
Other Long-Term Liabilities	**1**	11
Deferred Income Tax Liabilities	**13**	12
Long-Term Debt	**2,025**	2,468
	2,383	3,893

At December 31, 2020, certain consolidated VIEs had a redeemable non-controlling interest that ranked above the Company's equity interest. Refer to Note 6, Keystone XL, for additional information.

Non-Consolidated VIEs

The Company's non-consolidated VIEs consist of legal entities where the Company is not the primary beneficiary as it does not have the power 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.

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 $)	2021	2020
Balance sheet		
Loan receivable from affiliate (Note 11)	**1**	—
Equity investments		
Bruce Power	**4,493**	3,306
Pipeline equity investments and other[1]	**1,605**	1,371
Long-term loan receivable from affiliate (Note 11)	**238**	—
Off-balance sheet[2]		
Coastal GasLink[3]	**3,037**	1,107
Bruce Power	**974**	1,183
Pipeline equity investments[1]	**171**	399
Maximum exposure to loss	**10,519**	7,366

1 On November 30, 2021, TC Energy sold its remaining 15 per cent equity interest in Northern Courier. Refer to Note 28, Acquisitions and dispositions, for additional information.
2 Includes maximum potential exposure to guarantees and future funding commitments.
3 Represents the total capacity of $3,275 million committed under a subordinated loan agreement with Coastal GasLink LP less the $238 million balance outstanding under this loan agreement as at December 31, 2021. Refer to Note 11, Loans receivable from affiliates, for additional information.

Consent of Independent Registered Public Accounting Firm

We consent to the use of our reports, each dated February 14, 2022, with respect to the consolidated financial statements and the effectiveness of internal control over financial reporting included in this annual report on Form 40-F.

We also consent to the incorporation by reference of such reports in:

- 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. 333-151781, No. 333-161929, No. 333-208585, No. 333-250988 and No. 333-252123 on Form F-10 of TC Energy Corporation; and,

- Registration Statement No. 333-253333 and No. 333-261533 on Form F-10 of TransCanada PipeLines Limited.

/s/ KPMG LLP
Chartered Professional Accountants

February 14, 2022
Calgary, Canada

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 15, 2022

/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 15, 2022

/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 15, 2022

/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 15, 2022

/s/ JOEL E. HUNTER

Joel E. Hunter
Executive Vice-President and Chief Financial Officer

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, 2021 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 15, 2022

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, 2021 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 15, 2022

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, 2021 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 15, 2022

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, 2021 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 15, 2022

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Message from François Poirier

At TC Energy, we know what we do, and more importantly, how we do it, matters. We know our daily decisions and activities make a difference and impact all our stakeholders. We constantly strive to ensure our stakeholders, such as customers, suppliers, investors, lenders, regulators, Indigenous groups, neighbors and employees trust us, and feel confident they can count on us to make the right choices and to do the right thing.

Our corporate values – safety, responsibility, collaboration and integrity – form the foundation of how we do business. COBE helps us put those values into practice by clarifying what making the right choices and doing the right thing look like in action.

Every member of the TC Energy team is expected to read and understand the principles set out in COBE and is required to complete annual COBE training and certification. We encourage our teams to refer regularly to COBE to help guide ethical situations they may face at work, as it clarifies the behaviour expected.

We know it takes all of us living our values every day to ensure TC Energy continues to be a company our stakeholders and the public can count on. We're committed to making the right choices and doing the right thing, while fostering an environment where we respectfully keep each other accountable.

François Poirier
President & CEO

TC Energy

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Our expectations and your responsibilities

The Code of Business Ethics (COBE) Policy reinforces TC Energy Corporation's (the Company'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, 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 operated entities in all countries in which TC Energy conducts business.

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.

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 disciplinary action up to and including termination.

TC Energy

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Ethics Help Line
Canada / U.S. 1-888-920-2042
Mexico 800-099-0445
TCEnergy.com/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.

Integrity

We act with high ethical standards, treat others with honesty and respect, and keep promises and commitments to stakeholders.

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.

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.

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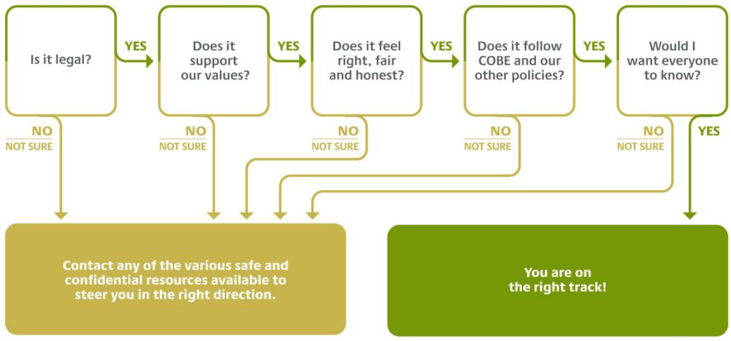
- Reporting safety, legal and ethical violations
- Leader responsibilities
- Zero is Real: Protecting health, safety and the environment
- Life Saving Rules
- Alcohol and drug use
- Diversity and employment equity
- Harassment and violence-free workplace
- Protecting everyone from weapons in the workplace

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 that all Personnel must carry out in everything we do. It's fundamental to how we do business. 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 the good-faith reporting of an incident or issue
- 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 fundamental 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 you can be assured that your confidentiality and identity will be protected to the greatest extent possible.

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 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
- Law department
- Privacy Office
- Harassment Investigation Coordinator
- Safety Personnel
- TC Energy's Environment Health and Safety Management (EHSM) Incident Management System

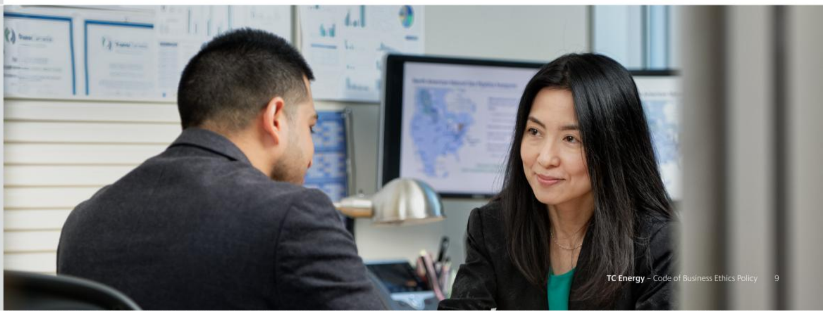
If you are uncomfortable speaking to any of these resources or if you would like to remain anonymous, you can contact the Ethics Help Line.

Leader responsibilities

TC Energy's leaders are here to help us make the right choices and do the right thing together.

If you are a leader, in addition to acting in accordance to the principles set out in COBE, you are required to:

- Inspire Personnel to act ethically by setting an ethical tone within your team
- Reinforce the importance of making the right choices and doing the right thing when carrying out other corporate objectives (for example, profits and cost management) and support those who are unsure how to make the right choices and do the right thing
- Set an example by modeling exemplary ethical business conduct
- Create a safe environment where individuals are encouraged to speak up if they become aware of or suspect a legal or ethical violation
- Ensure that your team members understand and act in accordance with all legal and ethical requirements that impact them in their jobs, that they know how to report actual or potential non-compliance with the law or COBE or to ask questions regarding ethical or legal matters, and that they complete all required ethics and compliance-related training
- Understand your obligation to act on any actual or suspected violations of COBE, any of our other policies, or the law that may be reported to you and the requirement for you to report these issues, as appropriate, to your Compliance Coordinator, Corporate Compliance, Internal Audit, the Harassment Investigation Coordinator, Privacy Office or the Ethics Help Line
- Engage with Human Resources, your Compliance Coordinator, Corporate Compliance or Internal Audit to ensure violations of legal requirements or COBE by your direct reports are addressed appropriately (including appropriate corrective disciplinary action)



Zero is Real

Protecting health, safety and the environment

Our commitment to safety isn't just words – it's a belief and a requirement that underpins everything our Personnel do. It's how we work 24/7, 365 days of the year across our entire organization.

We expect that our Personnel share TC Energy's commitment to safety.

Whether you work in a field location or in an office setting, you must ensure that you always 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.

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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 drugs, alcohol 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 drugs or alcohol 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 corrective disciplinary action up to and including termination.

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 has the potential to change or adversely affect the way a person thinks, feels, or acts.

TC Energy

TC Energy

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.

Equal Employment Opportunity and Non-Discrimination Policy

Harassment-Free Workplace Policy
Canada • U.S. • Mexico

Reasonable Workplace Accommodation Policy

TC Energy requires you to be tolerant, inclusive and to demonstrate respect for others.

While acting on behalf of TC Energy, you must never discriminate against anyone on the basis of:

- Gender
- Race
- National or ethnic origin
- Colour
- Disability
- Religion
- Age
- Sexual orientation and gender identity
- Marital status
- Family status
- Veteran status
- National Guard or reserve unit obligations
- A criminal conviction
- Or any other legally protected grounds

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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 Personnel 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 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 should never take actions or make unwanted comments or gestures that relate to:

- Gender
- Race
- National or ethnic origin
- Colour
- Disability
- Religion
- Age
- Sexual orientation and gender identity
- Marital status
- Family status
- Veteran status
- National Guard or reserve unit obligations
- A criminal conviction
- Or any other legally protected grounds

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); and
- 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 lawfully carry firearms (openly or in a concealed manner) are not exempt from our Policy, unless otherwise prohibited by law.

Ethical Business Conduct

- Avoiding conflicts of interest
- Personal Relationships
- Gifts 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 and terrorist financing

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 so it can be appropriately investigated and addressed.

You should never make 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

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 TC Energy 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 Relationships within the Company is permissible, they should immediately discuss their situation with their TC Energy leader, Human Resources (HR) Consultant 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 person is not in a 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), that are in conflict with or 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;
- 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; and
- An outside business activity that requires Personnel to violate their confidentiality or other obligations to TC Energy.

TC Energy Personnel whose spouse, common law partner, or other family member is 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 TC Energy 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 to the **Corporate Compliance department**.

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.

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.

Personnel may accept food and beverages over a business meal, provided it is not lavish, but may not accept invitations to events or sporting activities, cash or cash equivalents, or gifts with a value greater than $50.

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 $50 per instance or total more than $100 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.*

Expenses for 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

Enhanced Community Support 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.

Many anti-corruption laws allow small gifts or reasonable meals 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.

Political contributions and lobbying

TC Energy respects the political process and only makes political contributions and engages in lobbying activities that are legal and transparent.

Legal requirements concerning political contributions and lobbying are aimed at preventing corruption in government and at ensuring the proper functioning of the political system. These legal requirements can be complex and vary by jurisdiction (we are not allowed to make political donations at all in some jurisdictions). Therefore, you must seek approval from the appropriate department before engaging in these activities on behalf of TC Energy.

QUESTION: *I am very politically active. Is that allowed?*

ANSWER: *TC Energy encourages you to participate in the political process as an individual, in accordance with your own political views and the laws and regulations governing this activity. In doing so, however, you may not use TC Energy's name, nor indicate that you represent TC Energy, unless you have been authorized to do so.*

Avoiding Bribery and Corruption Policy

Political Activities and Contributions Policy

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

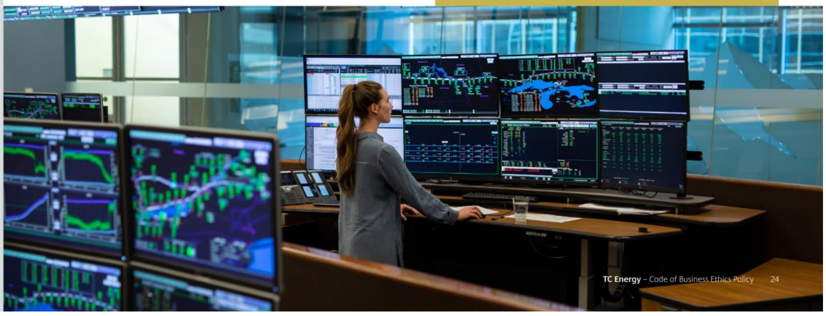
Prior to engaging in any transaction, you must ensure:

- **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 it has purchased when it crosses a border (e.g., because it takes ownership, or title, on delivery), it 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, vendors, suppliers 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.

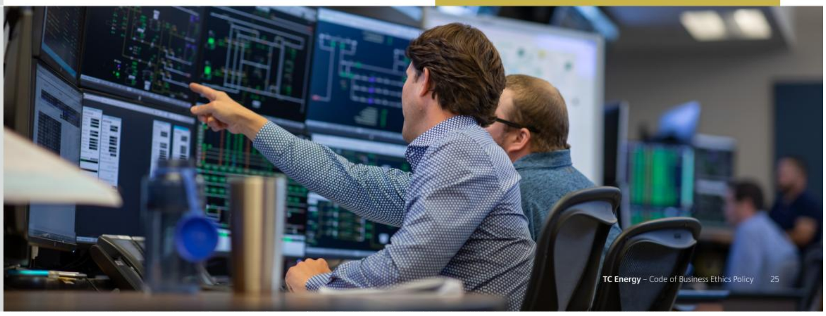
Trading Policy for Employees and Insiders

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.



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 Comisión Nacional de Hidrocarburos, and the North American Energy Reliability Corporation (NERC), 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 (SOCs) 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 can not give undue preference to any customer, whether it is an affiliated 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 is 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) 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

As such, 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.*

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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 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 disciplinary action up to and including termination.

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.

TC Energy

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.

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 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 Governance Committee of the TC Energy's Board of Directors.

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; and
- 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.

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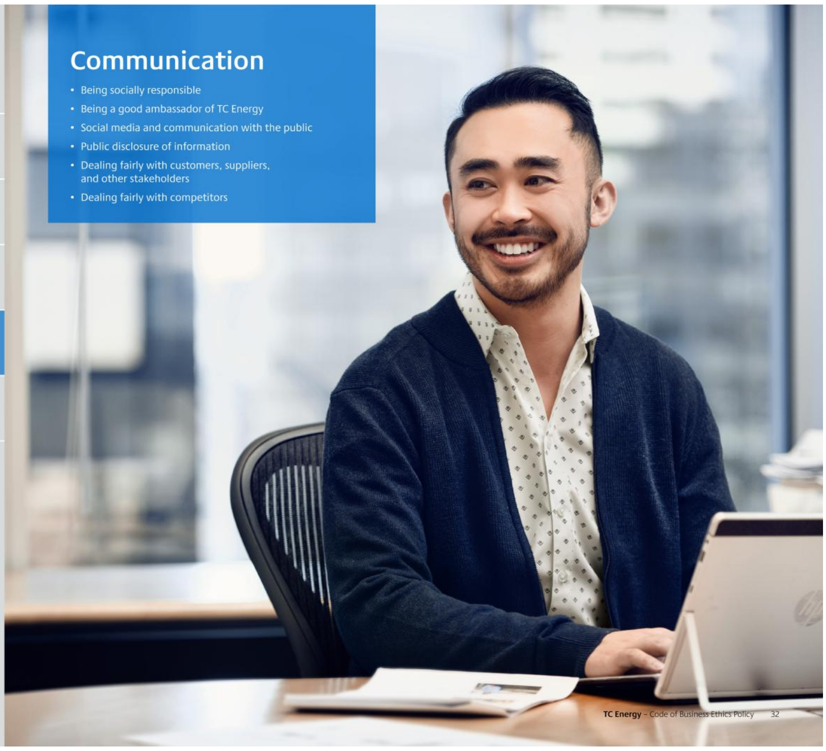
- Being socially responsible
- Being a good ambassador of TC Energy
- Social media and communication with the public
- Public disclosure of information
- Dealing fairly with customers, suppliers, and other stakeholders
- Dealing fairly with competitors



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Being socially responsible

We respect human rights and we are 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 other 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.

Stakeholder Engagement Commitment Statement

Indigenous Relations Commitment Statement

Indigenous Relations Policy

TC Energy

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 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 vendors, unless those discounts or rebates are available to all Employees.

Dealing fairly with customers, suppliers and other stakeholders

We consider the impact of our actions on stakeholders, the environment and the communities in which we operate. We follow the requirements of TC Energy's Operational Management System (TOMS) which are in place to make sure we act responsibly to protect us, our co-workers, our workplace and assets and the communities we work in, and that we act as responsible stewards of the environment. TOMS provides a strong foundation to manage risk, share knowledge and best practices, and it ensures continual improvement of the business.

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, suppliers and other stakeholders and we honour our obligations and commitments to them.

Treating customers, Contractors, suppliers 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

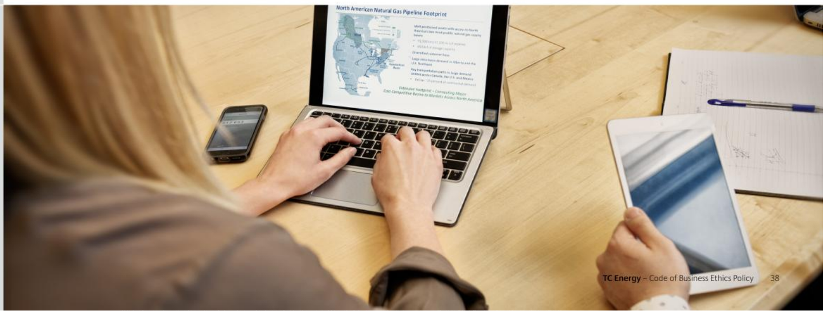
It also requires that you are honest and forthright when dealing with others (never omitting important facts, manipulating another person or situation, or misrepresenting yourself or TC Energy), and that you honour TC Energy's contractual, regulatory and other commitments.

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

TC Energy

Protecting confidential information

We protect TC Energy's confidential information, and that of our customers, suppliers, 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, suppliers, 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

Because such information is 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).

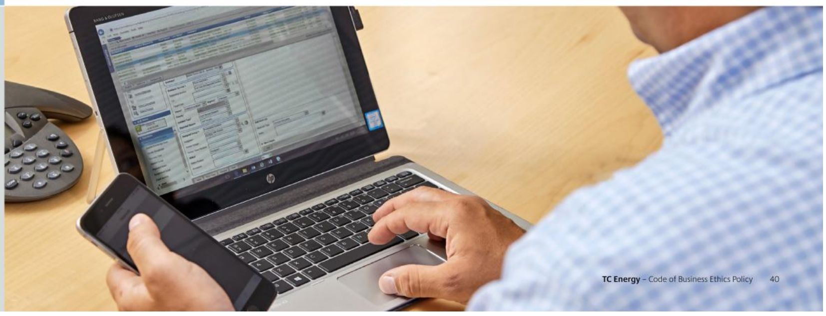
All confidential information should be protected from unauthorized access. When disposing of confidential information, you should do so in a secure manner, which may include shredding of hard copies.

See additional information in the Protecting and Using 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 Personnel, customers, Contractors, vendors, suppliers 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. 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, a landowner or a shareholder (to name just a few examples), you may not disclose that personal information to others, either within or outside TC Energy, without the express approval of TC Energy's Privacy Officer or the individual's written consent.

If you are ever unsure if information can be disclosed, you should check with TC Energy's Privacy Officer before taking any action.

For more information, please see the Protection of Personal Information Policy.

TC Energy is committed to protecting personal information in compliance with all legal requirements and requires that our Contractors, vendors, and suppliers share this commitment to information security.

Protection of Personal Information Policy.

Use of personal information must be limited to the business purposes for which the information was provided. 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 the Company 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

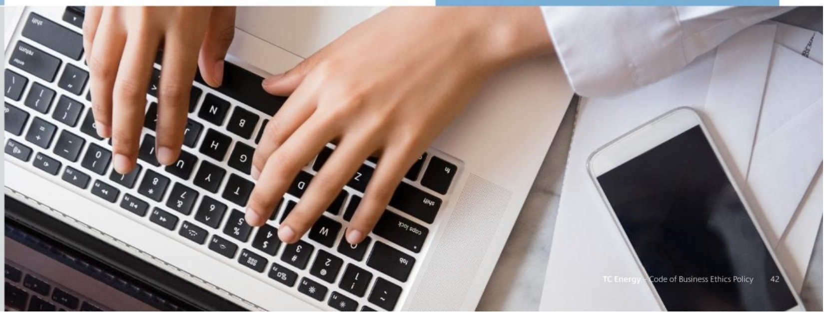
What is an information asset?

- 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

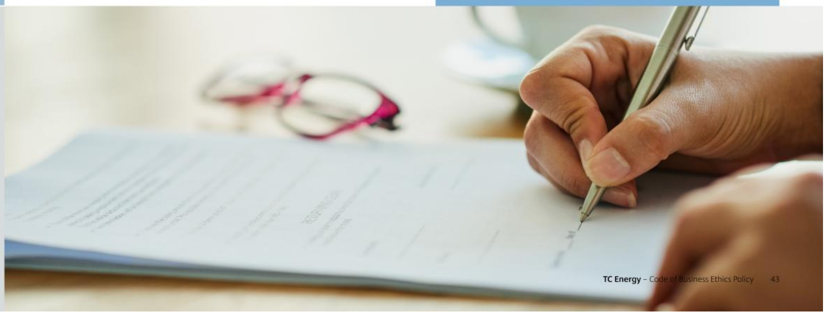
We preserve TC Energy's intellectual property rights and respect and honour those of third parties.

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.

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 vendors, suppliers, and 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 you have access to assist in 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 assets from loss, theft, damage and misuse.

Additionally, using Company facilities and/or equipment 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 corrective disciplinary action up to and including termination.

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. Therefore, 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 is a Company asset?

Company assets can include:

- 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:

- Work on your personal assets or for personal activities
- 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:*

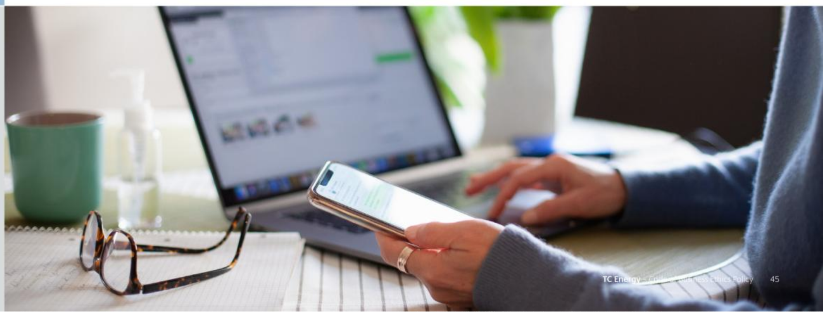
- *personal online purchases, such as electronics, clothing, footwear, hygiene/beauty products, food, contact lenses/glasses, book of the month/wine of the month or any other shipments for interest group meetings, including those created by and for Personnel*
- *personal magazine and newspaper subscriptions, except for business correspondence, trade publications and vendor catalogues*
- *gifts from friends and family, except for flower deliveries and gifts from vendors, Contractors, and suppliers which must comply with all applicable TC Energy's 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?*

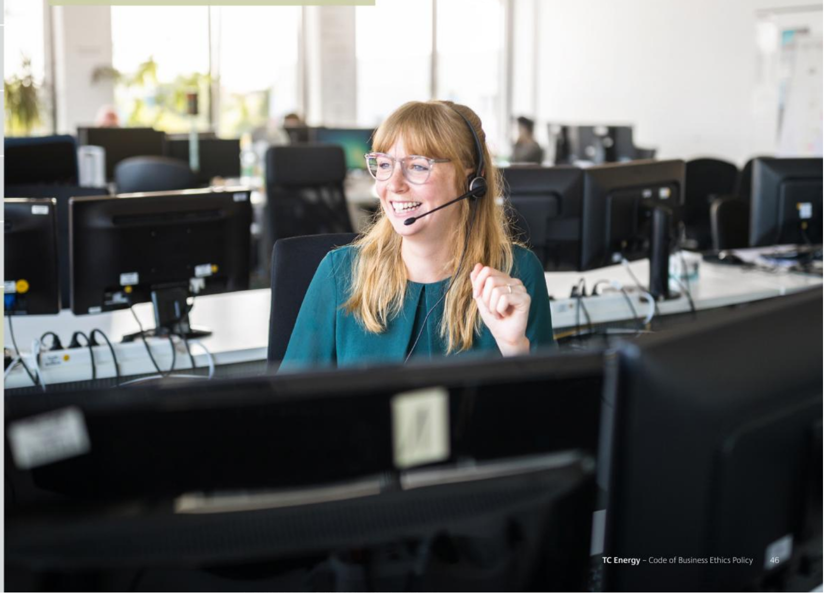
ANSWER: *Storing your bike in the Company's shed for the winter is not be acceptable. Storing personal property that is not required during work hours, such as motorized and nonmotorized vehicles, including but not limited to bicycles, motorcycles, RVs and boats, on the Company premises is generally 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; and*
- *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.*



Have a question? We're here to help

- Compliance and non-retaliation
- Asking questions and reporting concerns



Compliance

TC Energy requires that our Employees and Contractors comply with all aspects of this Policy and support others in doing so. You are responsible for promptly reporting suspected or actual violation of COBE, the associated and referenced policies, applicable law or any other concern, through available channels so that it can be appropriately investigated, addressed and handled. Anyone who fails to comply, or knowingly permits Personnel under their supervision not to comply, with the requirements set out in this document or any TC Energy rules and guidelines may lead to serious consequences including corrective disciplinary action, removal from our site(s) in accordance with the TC Energy's policies and processes, or termination of the business relationship.

Non-retaliation

We support and encourage you to report suspected instances of potential non-compliance with applicable laws, regulations and authorizations, as well as hazards, potential hazards, incidents involving health and safety or the environment, and near hits. We take every report seriously, investigate each report to identify facts, and make improvements to our practices and procedures when warranted.

All Employees and Contractors making reports in good-faith will be protected. We ensure immunity from disciplinary action or retaliation for Contractors, vendors and suppliers for the good-faith reporting of such concerns. Reports can be made to a TC Energy leader, your TC Energy representative, or anonymously to the Ethics Help Line.

Good-faith reporting is intended to remove protection for Contractors, vendors and suppliers making intentionally false or malicious reports, or who seek to exempt their own negligence or willful misconduct by the act of making a report.

Asking questions and reporting concerns

You are required to report any actual or potential non-compliance with COBE, any other TC Energy policies, or any legal obligation, as it applies to you or the Company, so it can be appropriately investigated and addressed. You can do so with confidence that your confidentiality and identity will be protected to the greatest extent possible and that retaliation for good faith reporting is prohibited.

Ethics Help Line

Although TC Energy has various reporting resources available for Personnel to report a concern or to seek guidance, there may be times when you are not comfortable raising concerns through those resources.

TC Energy's Ethics Help Line is operated by an independent third-party service provider, NAVEX Global, and reporting through the Ethics Help Line is confidential and may be done anonymously.

Canada/U.S. 1-888-920-2042
Mexico 800-099-0445
www.TCEnergy.com/ethics

All calls to the Ethics Help Line are free of charge, and can be made in English, French, or Spanish 24 hours a day, seven days a week, 365 days a year.

You may use the Ethics Help Line either to report any actual or suspected issues or to ask questions on topics such as:

- Accounting irregularities
- Alcohol and drug abuse
- Conflicts of interest
- Employee concerns
- Employment practices
- Engineering concerns
- Environment concerns
- Equitable treatment
- Safety concerns
- Sexual harassment
- Theft and fraud
- Workplace violence
- Other improprieties

If the issue raises an immediate threat to safety or security, you should contact Corporate Security, local police or other emergency services as appropriate.

All reports are taken seriously

Regardless of the means used to report, you can feel confident that the report will be taken seriously and that it will be investigated and addressed appropriately. If you are reporting anonymously through the Ethics Help Line, please make note of your key code for your case file as the investigator will only be able to contact you through your case file should they need to communicate with you for further information or clarification prior to initiating an investigation.

Participation in investigations and audits

Personnel, including directors and officers are required to participate in investigations and audits if, and as, requested.

QUESTION: *I suspect one of my colleagues has violated part of COBE, but I'm not sure my suspicions are correct. I'm concerned I'll be labeled a tattle-tale (or worse) if I report it. What should I do?*

ANSWER: *If you suspect misconduct, you should report it so it can be investigated. If it turns out not to be an issue, there will be no harm done. However, violations of the law or COBE that are not reported, cannot be addressed, and that can seriously undermine the Company. If that happens, we all suffer. If you report the issue, your confidentiality and identity will be protected and if any retaliation is found to occur, it will be taken very seriously.*

Glossary

Confidential Information means all TC Energy non-public information that may be of use to competitors or harmful to TC Energy or its customers, suppliers, or other stakeholders, if disclosed. It can include, but is in no way limited to, information regarding TC Energy's business, operations, finances, strategies or business plans, 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, photographs, electronic information assets (including emails, voicemails, SMS, and text messages), computer records or software, specifications, models, or other information which is or may be either applicable to or related in any way to the assets, business or affairs of TC Energy.

Contingent Workforce Contractor (CWC) means an individual who typically:

- 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; 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 and student employees of TC Energy.

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 are:

- Government ministers and their staff;
- Officials or Employees of government departments;
- Employees of regulatory agencies;
- Judges and judicial officials; and
- Employees of state-owned oil companies, or other government-owned or controlled corporations.

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.

Records means information created, received and maintained as evidence by an organization or person, pursuant to legal obligations or in the transaction of business. Records include, but are not limited to, electronic and physical formats. They provide proof of what happened, when it happened, and who made decisions. Whether information is identified as a Record depends on the information it contains and the context.

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
May 2021