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

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

For the fiscal year ended December 31, 2018

TRANSCANADA 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
(TransCanada Corporation)
(I.R.S. Employer Identification Number (if applicable))

52 - 2179728
(TransCanada PipeLines Limited)
(I.R.S. Employer Identification Number (if applicable))

TransCanada 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	Name of each exchange on which registered
Common Shares (including Rights under Shareholder Rights Plan) of TransCanada Corporation	**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:

x Annual information form x 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, 2018, 918,096,439 common shares;
9,498,423 Cumulative Redeemable First Preferred Shares, Series 1;
12,501,577 Cumulative Redeemable First Preferred Shares, Series 2;
8,533,405 Cumulative Redeemable First Preferred Shares, Series 3;
5,466,595 Cumulative Redeemable First Preferred Shares, Series 4;
12,714,261 Cumulative Redeemable First Preferred Shares, Series 5;
1,285,739 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;
20,000,000 Cumulative Redeemable First Preferred Shares, Series 13; and
40,000,000 Cumulative Redeemable First Preferred Shares, Series 15
of TransCanada Corporation were issued and outstanding.

At December 31, 2018, 887,333,320 common shares of TransCanada PipeLines Limited,
which were all owned by TransCanada 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 x 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 x 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.

The documents (or portions thereof) of 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
F-3	33-13564
F-3	333-6132
F-10	333-151781
F-10	333-161929
F-10	333-208585
F-10	333-214971
F-10	333-218711
F-10	333-221898
F-10	333-225941
F-10	333-228848

EXPLANATORY NOTE

TransCanada PipeLines Limited ("TransCanada PipeLines") is a wholly owned subsidiary of TransCanada Corporation ("TransCanada"). As of the date of filing of this Form 40-F, TransCanada PipeLines is relying on the continuous disclosure documents filed by TransCanada 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 TransCanada 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 TransCanada 2018 Management's discussion and analysis and audited consolidated financial statements to shareholders, except as otherwise specifically incorporated by reference in the TransCanada 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 112 through 190 of the TransCanada 2018 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 5 through 110 of the TransCanada 2018 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 111 of the TransCanada 2018 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" in Management's discussion and analysis on page 93 of the TransCanada 2018 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. Mr. John E. Lowe 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 Mr. Lowe and Mr. Vandal as audit committee financial experts does not make Mr. Lowe or Mr. Vandal "experts" for any purpose, impose any duties, obligations or liability on Mr. Lowe 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. The Registrants' Code is available on its website at www.transcanada.com. No waivers have been granted from any provision of the Code during the 2018 fiscal year.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

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 34 of the TransCanada 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 27 of the Notes to the audited consolidated financial statements attached to this Form 40-F and incorporated herein by reference.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

For information on tabular disclosure of contractual obligations, see "Contractual obligations" in Management's discussion and analysis on page 82 of the TransCanada 2018 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 13, 2019 (unless otherwise indicated) are:

Chair:	**J.E. Lowe**
Members:	**S. Crétier**
	S.B. Jackson (as of April 27, 2018)
	R. Limbacher (as of June 13, 2018)
	I. Samarasekera
	T. Vandal

FORWARD-LOOKING INFORMATION

We disclose forward-looking information to help current and potential investors 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 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
- expected cash flows and future financing options available, including portfolio management
- expected dividend growth
- expected future credit ratings
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures and contractual obligations
- expected regulatory processes and outcomes, including the impact of recent Federal Energy Regulatory Commission (FERC) policy changes (2018 FERC Actions)
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- the expected impact of future accounting changes, commitments and contingent liabilities
- expected industry, market and economic conditions.

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

- regulatory decisions and outcomes, including final outcomes of the 2018 FERC Actions
- planned and unplanned outages and the use of our pipeline and energy 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.

Risks and uncertainties

- 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 and energy assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the amount of capacity payments and revenues from our energy business due to plant availability
- production levels within supply basins
- construction and completion of capital projects
- costs for 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
- changes in environmental and other laws and regulations
- competition in the pipeline and energy sectors
- unexpected or unusual weather
- acts of civil disobedience
- cyber security and technological developments
- economic conditions in North America as well as globally
- our ability to effectively anticipate and assess changes to government policies and regulations.

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	TransCanada Corporation Annual information form for the year ended December 31, 2018.
13.2	Management's discussion and analysis (included on pages 5 through 110 of the TransCanada Corporation 2018 Management's discussion and analysis and audited consolidated financial statements to shareholders).
13.3	2018 Audited consolidated financial statements (included on pages 111 through 190 of the TransCanada Corporation 2018 Management's discussion and analysis and audited consolidated financial statements to shareholders), including the auditors' report thereon and the Report of Independent Registered Public Accounting Firm on the effectiveness of TransCanada's internal control over financial reporting as of December 31, 2018.
23.1	Consent of KPMG LLP, Chartered Professional Accountants, Independent Registered Public Accounting Firm.
31.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer regarding Periodic Report containing Financial Statements.
32.2	Certification of Chief Financial Officer regarding Periodic Report containing Financial Statements.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

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.

TRANSCANADA CORPORATION
TRANSCANADA PIPELINES LIMITED
(Registrants)

Per: /s/ DONALD R. MARCHAND

DONALD R. MARCHAND
Executive Vice-President and Chief Financial Officer

Date: February 14, 2019

EXHIBIT 13.1

TransCanada Corporation

2018 Annual information form

February 13, 2019

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Presentation of information

Throughout this Annual information form (AIF), the terms *we*, *us*, *our*, *the Company* and *TransCanada* mean TransCanada Corporation and its subsidiaries. In particular, *TransCanada* includes references to TransCanada PipeLines Limited (TCPL). Where TransCanada is referred to with respect to actions that occurred prior to its 2003 plan of arrangement (Arrangement) with TCPL, which is described in the *TransCanada Corporation – Corporate structure* section below, such actions were taken by TCPL or its subsidiaries. The term *subsidiary*, when referred to in this AIF, with reference to TransCanada means direct and indirect wholly owned subsidiaries of, and legal entities controlled by, TransCanada or TCPL, as applicable.

Unless otherwise noted, the information contained in this AIF is given at or for the year ended December 31, 2018 (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 TransCanada's management's discussion and analysis dated February 13, 2019 (MD&A) are incorporated by reference into this AIF as stated below. The MD&A can be found on SEDAR (www.sedar.com) under TransCanada'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 a 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 current and potential investors 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
- expected cash flows and future financing options available, including portfolio management
- expected dividend growth
- expected future credit ratings
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures and contractual obligations
- expected regulatory processes and outcomes, including the impact of recent Federal Energy Regulatory Commission (FERC) policy changes (2018 FERC Actions)
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- the expected impact of future accounting changes, commitments and contingent liabilities
- expected industry, market and economic conditions.

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

- regulatory decisions and outcomes, including final outcomes of the 2018 FERC Actions
- planned and unplanned outages and the use of our pipeline and energy 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.

Risks and uncertainties

- 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 and energy assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the amount of capacity payments and revenues from our energy business due to plant availability
- production levels within supply basins
- construction and completion of capital projects
- costs for 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
- changes in environmental and other laws and regulations
- competition in the pipeline and energy sectors
- unexpected or unusual weather
- acts of civil disobedience
- cyber security and technological developments
- economic conditions in North America as well as globally
- our ability to effectively anticipate and assess changes to government policies and regulations.

You can read more about these factors and others in the MD&A and other reports we have filed with Canadian securities regulators and the U.S. Securities and Exchange Commission (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 financial 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.

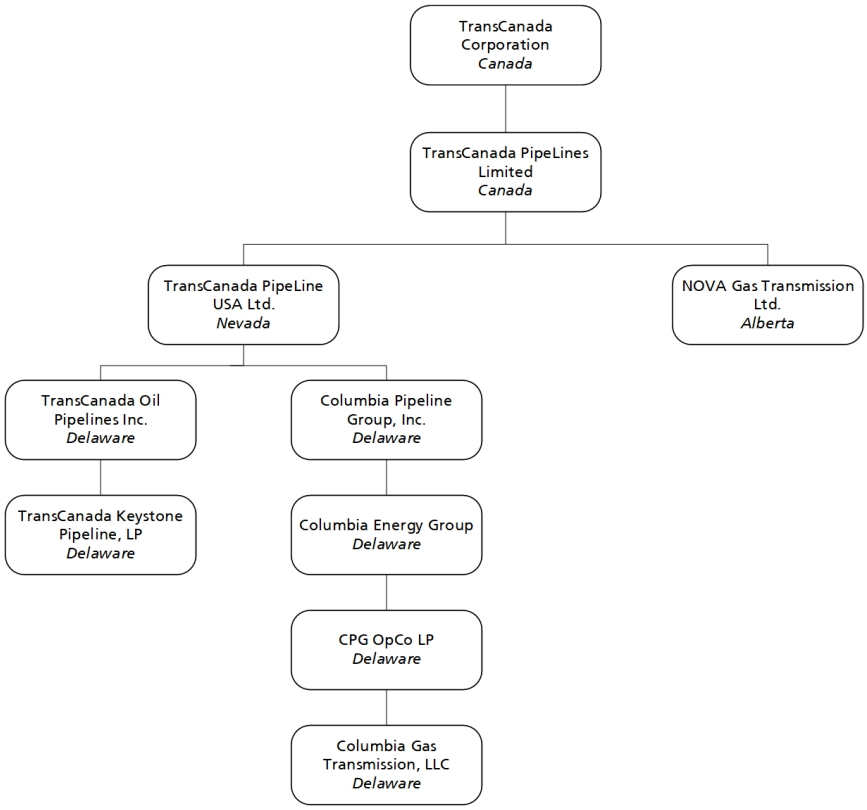
TransCanada Corporation

CORPORATE STRUCTURE

Our head office and registered office are located at 450 – 1 Street S.W., Calgary, Alberta, T2P 5H1. TransCanada was incorporated pursuant to the provisions of the *Canada Business Corporations Act* (CBCA) on February 25, 2003 in connection with the Arrangement, which established TransCanada 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 May 15, 2003. Pursuant to the Arrangement, the common shareholders of TCPL exchanged each of their TCPL common shares for one common share of TransCanada. The debt securities and preferred shares of TCPL remained obligations and securities of TCPL (the preferred shares of TCPL have been subsequently redeemed). TCPL continues to carry on business as the principal operating subsidiary of TransCanada. TransCanada does not hold any material assets directly other than the common shares of TCPL and receivables from certain of TransCanada's subsidiaries.

INTERCORPORATE RELATIONSHIPS

The following diagram presents the name and jurisdiction of incorporation, continuance or formation of TransCanada's principal subsidiaries as at Year End. Each of the subsidiaries shown has total assets that exceeded ten per cent of the total consolidated assets of TransCanada as at Year End or revenues that exceeded ten per cent of the total consolidated revenues of TransCanada as at Year End. TransCanada 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 TransCanada. The assets and revenues of excluded subsidiaries in the aggregate did not exceed 20 per cent of the total consolidated assets of TransCanada as at Year End or total consolidated revenues of TransCanada for the year then ended.

General development of the business

We operate in three core businesses – Natural Gas Pipelines, Liquids Pipelines and Energy. 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 Energy. We also have a Corporate segment, consisting of corporate and administrative functions that provide governance, financing and other support to the Company'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. Energy 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 Energy 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 2019. Further information about changes in our business that we expect to occur during the current financial year can be found in the *Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines* and *Energy* 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 - Expansion Programs	
2016	In 2016, we had approximately $2.3 billion of facilities that received regulatory approval and approximately $0.45 billion under construction. In October 2016, the Government of Canada approved our application for a $1.3 billion NGTL System expansion program. This NGTL System expansion program consists of five pipeline loops ranging in size from 24 to 48-inch pipe of approximately 230 km (143 miles) in length, and two compressor station unit additions of approximately 46.5 MW (62,360 hp). In 2016, we placed approximately $0.5 billion of new facilities in service.
2017	In June 2017, we announced a $2.0 billion expansion program on our NGTL System based on contracted customer demand for approximately 3.2 PJ/d (3 Bcf/d) of incremental firm receipt and delivery services, subject to regulatory approvals. Construction is expected to start in early 2019, with initial projects expected to be in service in fourth quarter 2019 and final projects in service in 2021. In 2017, we placed approximately $1.7 billion of new facilities in service.
2018	In February 2018, we announced the NGTL System 2021 Expansion Program with an estimated capital cost of $2.3 billion and an anticipated in-service date in the first half of 2021. This program consists of approximately 375 km (233 miles) of new pipeline, three compressor units, a control valve and associated facilities. The expansion is required to connect incremental supply and expand basin export capacity by 1.1 PJ/d (1 Bcf/d) to the Empress export delivery point at the interconnection of the NGTL System and the Canadian Mainline. An application to construct and operate the NGTL System 2021 Expansion Program was filed with the NEB in June 2018 and will proceed through a public hearing in third quarter 2019. In October 2018, we announced the NGTL System 2022 Expansion Program to meet capacity requirements for incremental firm receipt and intra-basin delivery services to commence in November 2021 and April 2022. This $1.5 billion expansion of the NGTL System consists of approximately 197 km (122 miles) of new pipeline, three compressor units, meter stations and associated facilities. Applications for approvals to construct and operate the facilities are expected to be filed with the NEB in second quarter 2019 and, pending receipt of regulatory approvals, construction would start as early as third quarter 2020. In 2018, we placed approximately $0.6 billion of projects in service.
NGTL System - North Montney Mainline (NMML)	
2016	In September 2016, the Government of Canada approved a sunset clause extension request that we filed in March 2016, for the NMML Certificate of Public Convenience and Necessity (CPCN), for one year to June 10, 2017.
2017	In March 2017, we filed an application with the NEB for a variance to the existing approvals for the NMML project to remove the condition that the project could only proceed once a positive FID was made for the Pacific Northwest LNG project. The NMML project consists of approximately 206 km (128 miles) of new pipeline, three compressor units and 14 meter stations. The NMML project is underpinned by restructured 20-year commercial contracts with shippers and is not dependent on the Pacific Northwest LNG project proceeding.

Date	Description of development
2018	In July 2018, the NEB issued an amending order and amended CPCN following the Government of Canada approval of our application, to the existing NMML project approvals to remove the condition requiring a positive FID for the Pacific Northwest LNG project prior to commencement of construction. The NEB directed NGTL to seek approval for a revised tolling methodology for the project following a provisional period defined as one year after the receipt of the Government of Canada decision, otherwise stand-alone tolling will be imposed as a default. NGTL is working with its shippers to address this requirement and is confident an acceptable tolling mechanism, other than stand-alone tolling, will be established. Construction on the NMML project was initiated in August 2018. The first phase of the project is anticipated to be in service by fourth quarter 2019, and the second phase by second quarter 2020. The current estimated project cost increased from original estimates by $0.2 billion to $1.6 billion mainly due to construction schedule delays and an increase in market-dependent construction costs.
NGTL System - Revenue Requirement Settlements	
2017	The two-year revenue requirement agreement for 2016-2017 Settlement expired on December 31, 2017. The 2016-2017 Settlement fixed ROE at 10.1 per cent on 40 per cent deemed common equity, established depreciation at a forecast composite rate of 3.16 per cent and fixed OM&A costs at $222.5 million annually. An incentive mechanism for variances enabled NGTL to capture savings from improved performance and provided for the flow-through of all other costs, including pipeline integrity expenses and emissions costs. On November 24, 2017, the NEB approved interim tolls for 2018.
2018	In June 2018, the NEB approved the 2018-2019 Revenue Requirement Settlement (2018-2019 Settlement), as filed, and the resulting final 2018 tolls. The 2018-2019 Settlement, which is effective from January 1, 2018 to December 31, 2019, fixes ROE at 10.1 per cent on 40 per cent deemed common equity and increases the composite depreciation rate from 3.18 per cent to 3.45 per cent. OM&A costs are fixed at $225 million for 2018 and $230 million for 2019 with a 50/50 sharing mechanism for any variances between the fixed amounts and actual OM&A costs. All other costs, including pipeline integrity expenses and emissions costs, are treated as flow-through expenses.
Canadian Mainline – Eastern Mainline Project	
2016	The Eastern Mainline project was conditioned on the approval and construction of the Energy East pipeline. Refer to the *General development of the business – Liquids Pipelines* section for information on Energy East.
2017	In October 2017, after a careful review of the changed circumstances, we informed the NEB that we would not be proceeding with the Energy East and Eastern Mainline project applications, that in effect provided public notice that the projects were canceled. Refer to the *General development of the business – Liquids Pipelines* section for information on Energy East.
Canadian Mainline - Long-Term Fixed-Price (LTFP) Services	
2017	In November 2017, we began offering a new NEB-approved service on the Canadian Mainline referred to as the Dawn LTFP service. This service enables WCSB producers to transport up to 1.5 PJ/d (1.4 Bcf/d) of natural gas at a simplified toll of $0.77/GJ from the Empress receipt point in Alberta to the Dawn hub in Southern Ontario. The LTFP service is underpinned by ten-year contracts that have early termination rights after five years. Any early termination will result in an increased toll for the last two years of the contract.
2018	In December 2018, we announced 670 TJ/d (625 MMcf/d) of new natural gas transportation contracts from the WCSB on the Canadian Mainline. Upon NEB approval of this LTFP service, referred to as the North Bay Junction (NBJ) LTFP service, incremental volumes under these LTFP contracts will reach markets in Ontario, Québec, New Brunswick, Nova Scotia and the Northeastern U.S. using existing capacity on the Canadian Mainline as well as new compression facilities. Customers have executed 15-year precedent agreements to proceed with the project with an estimated capital cost of $96 million.
2019	In January 2019, we filed an application for approval of the NBJ LTFP with the NEB, and expect a decision in third quarter 2019.
Canadian Mainline Settlement	
2017	While the NEB-approved Canadian Mainline's 2015-2030 tolls and tariff settlement (LDC Settlement) specified tolls for 2015-2020, the NEB ordered a toll review halfway through this six-year period. A supplemental agreement for the 2018-2020 period was executed between TransCanada and eastern LDCs and filed with the NEB in December 2017 (Supplemental Agreement). The Supplemental Agreement, supported by a majority of Canadian Mainline stakeholders, proposed lower tolls, preserved an incentive arrangement that provides an opportunity for 10.1 per cent, or greater return, on a 40 per cent deemed common equity and described the revenue requirements and billing determinants for the 2018-2020 period. Interim tolls for 2018, as established by the Supplemental Agreement, were filed and subsequently approved by the NEB in December 2017.
2018	In October 2018, we concluded the written hearing process for the Canadian Mainline 2018-2020 toll review with the filing of our reply evidence to the NEB. In December 2018, the NEB 2018 decision was issued (NEB 2018 Decision), approving all elements of the application, including our cost and volume forecasts, higher depreciation rates and continuation of pricing discretion, with the exception of the amortization period for the Long Term Adjustment Account (LTAA), which is now to be amortized over 2018 to 2020. The impact of the NEB 2018 Decision was reflected in lower tolls effective February 1, 2019.
2019	As directed by the NEB, we filed a compliance filing in January 2019, the outcome of which is expected in first quarter 2019.

Date	Description of development
LNG PIPELINE PROJECTS	
Prince Rupert Gas Transmission (PRGT)	
2016	In September 2016, PNW LNG received an environmental certificate from the Government of Canada for a proposed LNG plant at Prince Rupert, B.C. In December 2016, PNW LNG received an LNG export license from the NEB which extended the export term from 25 years to 40 years. We continued our engagement with Indigenous groups and signed project agreements with 14 First Nation groups along the pipeline route, which outlined financial and other benefits and commitments that would be provided to each First Nation for as long as the project was in service.
2017	In July 2017, we were notified that PNW LNG would not be proceeding with their proposed LNG project and that Progress Energy would be terminating their agreement with us for development of the PRGT project. In accordance with the terms of the agreement, we received a payment of $0.6 billion from Progress Energy in October 2017 for full recovery of our costs plus carrying charges.
Coastal GasLink	
2016	In first quarter 2016, we continued to engage with Indigenous groups and announced project agreements with 11 First Nation groups along the pipeline route, which outlined financial and other benefits and commitments that would be provided to each First Nation group for as long as the project was in service. We also continued to engage with stakeholders along the pipeline route and progressed detailed engineering and construction planning work to refine the capital cost estimate. In response to feedback received, we applied for a minor route amendment to the BCEAO in order to provide an option in the area of concern. In July 2016, the LNG Canada joint venture participants announced a delay to their FID for the proposed facility in Kitimat, B.C. We worked with LNG Canada to maintain the appropriate pace of the Coastal GasLink development schedule and work activities. We continued our engagement with Indigenous groups along our pipeline route and concluded long-term project agreements with 17 First Nation communities.
2017	The continuing delay in the FID for the LNG Canada project triggered a restructuring of the provisions in the Coastal GasLink project agreement with LNG Canada that resulted in the payment of certain amounts to TransCanada with respect to carrying charges on costs incurred. In 2017, we received payments of $88 million related to carrying charges on costs incurred since inception of the project. Coastal GasLink filed an amendment to the Environmental Assessment Certificate in November 2017 for an alternate route on a portion of the pipeline.
2018	In October 2018, we announced that we are proceeding with construction of the Coastal GasLink pipeline project following the LNG Canada joint venture participants' announcement that they had reached a positive FID to build the LNG Canada natural gas liquefaction facility in Kitimat, B.C. Coastal GasLink will provide the natural gas supply to the LNG Canada facility and is underpinned by 25-year TSAs (with additional renewal provisions) with each of the five LNG Canada participants. Coastal GasLink will be a 670 km (416 miles) pipeline with an initial capacity of approximately 2.2 PJ/d (2.1 Bcf/d) with potential expansion capacity up to 5.4 PJ/d (5.0 Bcf/d). All necessary regulatory permits have been received to allow us to proceed with construction activities which began in December 2018, with a planned in-service date in 2023. Coastal GasLink has signed project and community agreements with all 20 elected Indigenous bands along the pipeline route, confirming strong support from Indigenous communities across the province of B.C. In July 2018, an individual asked the NEB to consider whether the Coastal GasLink pipeline should be federally regulated by the NEB. In October 2018, the NEB advised that it would consider the question of jurisdiction, granted Coastal GasLink standing in the matter, and reserved the right to decide on the participation of all other potentially interested parties, including the individual who raised the question. In December 2018, the NEB issued a process letter addressing participation and set the schedule which is expected to conclude in the second half of 2019, with a decision to follow. In December 2018, the B.C. Supreme Court issued an interim injunction, ordering opponents of the Coastal GasLink project to allow pipeline construction workers access to a blockaded area of the Coastal GasLink right of way, south of Houston, B.C. The Coastal GasLink capital cost estimate is $6.2 billion with the majority of the construction spend occurring in 2020 and 2021. Subject to terms and conditions, differences between the estimated capital cost and final cost of the project will be recovered in future pipeline tolls. As part of the Coastal GasLink funding plan, we are exploring joint venture partners and project financing. The total capital cost includes pre-FID costs incurred of $470 million. In accordance with provisions in the agreements with the LNG Canada joint venture participants, all five parties elected to reimburse us for their share of pre-FID costs, totaling $470 million, in November 2018. In addition, all five LNG Canada joint venture participants elected to make cash payments throughout the construction period with respect to carrying charges on costs incurred.
2019	In January 2019, the RCMP moved to enforce the injunction issued by the B.C. Supreme Court. Following negotiations, the blockaders agreed to abide by the terms of the injunction and allow access to the area.

Developments in the U.S. Natural Gas Pipelines Segment

Date	Description of development
U.S. NATURAL GAS PIPELINES - COLUMBIA	
Columbia Acquisition	
2016	On July 1, 2016, we acquired 100 per cent ownership of Columbia for a purchase price of US$10.3 billion in cash. The acquisition was initially financed through proceeds of $4.4 billion from the sale of subscription receipts, draws on acquisition bridge facilities in the aggregate amount of US$6.9 billion and existing cash on hand. The sale of the subscription receipts was completed on April 1, 2016, through a public offering, and following the closing of the acquisition, the subscription receipts were exchanged into 96.6 million TransCanada common shares.
Columbia Pipeline Partners LP (CPPL)	
2016	In November 2016, we announced that we entered into an agreement and plan of merger through which Columbia agreed to acquire, for cash, all of the outstanding publicly held common units of CPPL.
2017	In February 2017, we completed the acquisition, for cash, of all outstanding publicly held common units of CPPL at a price of US$17.00 and a stub period distribution of US$0.10 per common unit for an aggregate transaction value of US$921 million.
Columbia Gas - Leach XPress	
2016	The FEIS for the Leach XPress project was received in September 2016. The project transports approximately 1.6 PJ/d (1.5 Bcf/d) of Marcellus and Utica gas supply to delivery points along the pipeline and to the Leach interconnect with Columbia Gulf, and consists of 260 km (160 miles) of 36-inch greenfield pipe, 39 km (24 miles) of 36-inch loop, three km (two miles) of 30-inch greenfield pipe, 82.8 MW (111,000 hp) of greenfield compression and 24.6 MW (33,000 hp) of brownfield compression.
2018	The US$1.6 billion project was placed in service in January 2018.
Columbia Gas - Mountaineer XPress	
2016	The FERC 7(C) application for the Mountaineer XPress project was filed in April 2016. The project is 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, ten 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.
2017	The FERC certificate for the Mountaineer XPress project was received in December 2017.
2019	Approximately 45 per cent of the Mountaineer XPress project was placed in service in January 2019, with the remainder to be placed in service in February and March 2019, along with Gulf Xpress (see *Columbia Gulf - Gulf XPress* below). Total estimated project costs have been revised upwards to US$3.2 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 - WB XPress	
2017	The FERC certificate for the WB XPress project was received in November 2017.
2018	The WB XPress project, designed to transport approximately 1.4 PJ/d (1.3 Bcf/d) of Marcellus gas supply westbound to the Gulf Coast and eastbound to Mid-Atlantic markets, was placed in service in October 2018 and November 2018 for the Western Build and Eastern Build, respectively.
Columbia Gas - Buckeye XPress	
2017	The Buckeye XPress project represents an upsizing of an existing pipeline replacement project in conjunction with our Columbia Gas modernization program. The US$0.2 billion cost to upsize the replacement pipe and install compressor upgrades will enable us to offer approximately 290 TJ/d (275 MMcf/d) of incremental pipeline capacity to accommodate growing Appalachian production. We expect the project to be placed in service in late-2020.
Columbia Gulf - Rayne XPress	
2016	The FEIS for the Rayne XPress project was received in September 2016. The project transports approximately 1.1 PJ/d (1 Bcf/d) of supply from an interconnect with the Leach XPress pipeline project and another interconnect, to markets along the system and to the Gulf Coast. The project consists of bi-directional compressor station modifications along Columbia Gulf, 38.8 MW (52,000 hp) of greenfield compression, 20.1 MW (27,000 hp) of replacement compression and six km (four miles) of 30-inch pipe replacement.
2017	The US$0.4 billion project was placed in service in November 2017.

Date	Description of development
Columbia Gulf - Gulf XPress	
2016	The FERC 7(C) application for the Gulf XPress project was filed in April 2016. 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.
2017	The FERC certificate for the Gulf XPress project was received on December 29, 2017.
2019	The US$0.6 billion project is expected to be placed in service in February and March 2019.
Columbia Gulf - Cameron Access	
2018	The Cameron Access project, designed to transport approximately 0.9 PJ/d (0.8 Bcf/d) of gas supply to the Cameron LNG export terminal in Louisiana, was placed in service in March 2018.
Columbia Gulf - Louisiana XPress	
2018	In November 2018, we sanctioned the Louisiana XPress project which will connect supply directly to Gulf Coast LNG export markets with the addition of three greenfield mid-point compressor stations along Columbia Gulf. The estimated US$0.4 billion project is expected to be placed in service in 2022.
Modernization I & II	
2017	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 program includes, among other things, replacement of aging pipeline and compressor facilities, enhancements to system inspection capabilities, and improvements in control systems. The US$1.5 billion Modernization I arrangement was completed under the terms of a 2012 settlement agreement, with the final US$0.2 billion spent in 2017. Modernization II has been approved for up to US$1.1 billion of work starting in 2018 and to be completed through 2020. As per terms of the arrangements, facilities in service by October 31 collect revenues effective February 1 of the following year.
OTHER U.S. NATURAL GAS PIPELINES	
ANR Pipeline	
2016	ANR Pipeline filed a Section 4 Rate Case that requested an increase to ANR's maximum transportation rates in January 2016. Shifts in ANR's traditional supply sources and markets, necessary operational changes, needed infrastructure updates, and evolving regulatory requirements were driving required investment in facility maintenance, reliability and system integrity as well as an increase in operating costs that resulted in the current tariff rates not providing a reasonable return on our investment. We also pursued a collaborative process to find a mutually beneficial outcome with our customers through settlement negotiations. ANR's last rate case filing was more than 20 years ago. ANR reached a settlement with its shippers effective August 1, 2016 and received FERC approval on December 16, 2016. Per the settlement, transmission reservation rates would increase by 34.8 per cent and storage rates would remain the same for contracts one to three years in length, while increasing slightly for contracts of less than one year and decreasing slightly for contracts more than three years in duration. There is a moratorium on any further rate changes until August 1, 2019. ANR may file for new rates after that date if it has spent more than US$0.8 billion in capital additions, but must file for new rates no later than an effective date of August 1, 2022.
Great Lakes	
2017	In October 2017, Great Lakes filed a rate settlement with the FERC to satisfy its obligations from its previous 2013 rate settlement for new rates to be in effect by January 1, 2018 (2017 Great Lakes Rate Settlement). In conjunction with the Canadian Mainline's LTFP service (see *Canadian Regulated Pipelines – Long-Term Fixed-Price Service* above), Great Lakes entered into a new ten-year gas transportation contract with the Canadian Mainline. This NEB-approved contract, effective November 1, 2017, contains volume reduction options up to full contract quantity beginning in year three.
Portland Natural Gas Transmission System (Portland)	
2016	In January 2016, we closed the sale of our 49.9 per cent of our total 61.7 per cent interest in Portland to TC PipeLines, LP (TCLP) for US$223 million. Proceeds were comprised of US$188 million in cash and the assumption of US$35 million of a proportionate share of Portland debt.
2017	In June 2017, we closed the sale of a 49.34 per cent of our 50 per cent interest in Iroquois, along with an option to sell the remaining 0.66 per cent at a later date, to TCLP. At the same time, we closed the sale of our remaining 11.81 per cent interest in Portland to TCLP. Proceeds from these transactions were US$765 million, before post-closing adjustments, and were comprised of US$597 million in cash and US$168 million representing a proportionate share of Iroquois and Portland debt. In December 2017, Portland executed precedent agreements with several LDCs in New England and Atlantic Canada to re-contract certain system capacity set to expire in 2019, as well as expand the Portland system to bring its certificated capacity from 222 TJ/d (210 MMcf/d) up to 290 TJ/d (275 MMcf/d). The approximate US$80 million Portland XPress Project will proceed concurrently with upstream capacity expansions. The in-service dates of the Portland XPress project are being phased-in over a three-year period, beginning November 1, 2018.
2018	Phase I of Portland XPress was placed in service on November 1, 2018.

Date	Description of development
Iroquois Gas Transmission System, L.P. (Iroquois)	
2016	FERC approvals were obtained for settlements with shippers for our Iroquois, Tuscarora and Columbia Gulf pipelines in third quarter 2016. In March 2016, we acquired an additional 4.87 per cent interest in Iroquois for an aggregate purchase price of US$54 million and in May 2016, a further 0.65 per cent was acquired for US$7 million. As a result, our interest in Iroquois increased to 50 per cent.
2017	In June 2017, we closed the sale of a 49.34 per cent of our 50 per cent interest in Iroquois, along with an option to sell the remaining 0.66 per cent at a later date, to TCLP. At the same time, we closed the sale of our remaining 11.81 per cent interest in Portland to TCLP. Refer to the *Portland Natural Gas Transmission System* section above.

Developments in the Mexico Natural Gas Pipelines segment

Date	Description of development
MEXICO NATURAL GAS PIPELINES	
Topolobampo	
2016	In November 2012, we were awarded the contract to build, own and operate the Topolobampo project. Construction on the project is supported by a 25-year TSA for 720 TJ/d (670 MMcf/d) with the CFE. The Topolobampo project is a 560 km (348 miles), 30-inch pipeline that will receive gas from the upstream pipelines near El Encino, Chihuahua, and will deliver natural gas from these interconnecting pipelines to delivery points along the pipeline route including our Mazatlán pipeline at El Oro, Sinaloa.
2017	The Topolobampo project was substantially complete, excluding a 20 km (12 miles) section due to delays experienced by the Secretary of Energy, the government department which conducts indigenous consultations in Mexico. Under the terms of the TSA, the delays were recognized as a force majeure event with provisions allowing for the collection of revenue as per the original TSA service commencement date of July 2016. The pipeline cost is approximately US$1.2 billion, an increase of US$0.2 billion from the original estimate, due to the delays.
2018	The Topolobampo project was placed in service in June 2018.
Mazatlán	
2016	In November 2012 we were awarded the contract to build, own and operate the Mazatlán project. This project is a 430 km (267 miles), 24-inch pipeline running from El Oro to Mazatlán, Sinaloa, with an estimated cost of US$0.4 billion. This pipeline is supported by a 25-year natural gas TSA for 214 TJ/d (200 MMcf/d) with the CFE. Physical construction was completed in 2016 and was awaiting natural gas supply from upstream interconnecting pipelines. We met our obligations and collected revenue as per provisions in the contract and per the original TSA service commencement date of December 2016.
2017	The Mazatlán project was placed into full service in July 2017.
Tula	
2016	In November 2015, we were awarded the contract to build, own and operate the 36-inch, 324 km (201 miles) pipeline with a 16-inch, 24 km (15 miles) lateral, supported by a 25-year natural gas TSA for 949 TJ/d (886 MMcf/d) with the CFE. The pipeline will transport natural gas from Tuxpan, Veracruz to markets near Tula, extending through the states of Puebla and Hidalgo.
2017	Construction of the Tula pipeline was substantially completed in 2017, with the exception of approximately 90 km (56 miles) of the pipeline.
2018	The CFE has approved the recognition of force majeure events for the Tula pipeline, including the continuation of the payment of fixed capacity charges to us that began in first quarter 2018. Commencement of constructing the central segment of the project has been delayed due to a lack of progress by the Secretary of Energy, the governmental department responsible for indigenous consultation. Project completion has been revised to the end of 2020. We have negotiated separate CFE contracts that would allow certain segments of the pipeline to be placed in service when gas is available.
Villa de Reyes	
2016	In April 2016, we were awarded the contract to build, own and operate the 36- and 24-inch Villa de Reyes pipelines, totaling 420 km (261 miles). Construction of the pipeline is supported by a 25-year natural gas TSA for 949 TJ/d (886 MMcf/d) with the CFE. The bi-directional pipeline will transport natural gas from Tula, Hidalgo to Villa de Reyes, San Luis Potosí, connecting to the Tamazunchale and Tula pipelines including a lateral to the Salamanca industrial complex in Guanajuato.
2017	Construction of the project commenced, however, delays due to archeological investigations by state authorities caused the in-service date to be revised to the second half of 2019.
2018	The CFE has approved the recognition of force majeure events for the Villa de Reyes pipeline, including the continuation of the payment of fixed capacity charges to us that began in first quarter 2018. Construction for the project is ongoing and is anticipated to be in service in the second half of 2019. We have negotiated separate CFE contracts that would allow certain segments of the pipeline to be placed in service when gas is available.

Date	Description of development
Sur de Texas	
2016	The Sur de Texas project is a joint venture with IEnova in which we hold a 60 per cent interest representing an investment of approximately US$1.3 billion. Construction of the pipeline is supported by a 25-year natural gas TSA for 2.8 PJ/d (2.6 Bcf/d) with the CFE. The 42-inch, 775 km (482 miles) pipeline will begin offshore in the Gulf of Mexico, at the border near Brownsville, Texas, and end in Tuxpan, Veracruz. The project will deliver natural gas to our Tamazunchale and Tula pipelines and to other third-party facilities.
2017	Approximately 60 per cent of the off-shore construction completed at December 31, 2017.
2018	Offshore construction was completed in May 2018 and the project continues to progress toward an anticipated in-service date in early second quarter 2019. An amending agreement was signed with the CFE that recognizes force majeure events and the commencement of payments of fixed capacity charges began on October 31, 2018.

Further information about developments in the Natural Gas Pipelines business, including changes that we expect will occur in the current financial year, 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

Development in the Liquids Pipelines Segment

Date	Description of development
Keystone Pipeline System	
2016	The Houston Lateral pipeline and terminal, an extension from the Keystone Pipeline to Houston, Texas, went into service in August 2016. The terminal has an initial storage capacity for 700,000 barrels of crude oil. The HoustonLink pipeline which connects the Houston Terminal to Magellan's Houston and Texas City, Texas delivery system was completed in December 2016. The CITGO Petroleum (CITGO) Sour Lake pipeline connection between the Keystone Pipeline and CITGO's Sour Lake, Texas terminal was placed in service in December 2016.
2017	In fourth quarter 2017, we concluded open seasons for the Keystone pipeline and Marketlink and secured incremental long-term contractual support. In November 2017, the Keystone pipeline was temporarily shut down after a leak was detected in Marshall County, South Dakota. The estimated volume of the release was 5,000 barrels as reported to the NRC and the PHMSA. On November 29, 2017, the pipeline was repaired and returned to service at a reduced pressure in the affected section of the pipeline. This shutdown did not have a significant impact on our 2017 earnings.
2018	In 2018, we concluded successful open seasons for Marketlink securing incremental contractual support. We continue to expand our terminal facilities which are integral to our operations, with the completion of an additional one million barrels of storage at Cushing, Oklahoma.
Keystone XL	
2016	In January 2016, the South Dakota PUC accepted Keystone XL's certification that it continued to comply with the conditions in its existing 2010 permit authority in the state. In January 2016, we filed a Notice of Intent to initiate a claim under Chapter 11 of NAFTA in response to the U.S. Administration's decision to deny a Presidential permit for the Keystone XL Pipeline on the basis that the denial was arbitrary and unjustified. Through the NAFTA claim, we were seeking to recover more than US$15 billion in costs and damages that we estimated to have suffered as a result of the U.S. Administration's breach of its NAFTA obligations. In June 2016, we filed a Request for Arbitration in a dispute against the U.S. Government pursuant to the Convention on Settlement of Investment Disputes between States and Nationals of Other States, the Rules of Procedure for the Institution of Conciliation and Arbitration Proceedings and Chapter 11 of NAFTA. In January 2016, we also filed a lawsuit in the U.S. Federal Court in Houston, Texas, asserting that the U.S. President's decision to deny construction of Keystone XL exceeded his power under the U.S. Constitution. The federal court lawsuit did not seek damages, but rather a declaration that the permit denial was without legal merit and that no further Presidential action was required before construction of the pipeline could proceed.
2017	In January 2017, the U.S. President signed a Presidential Memorandum inviting TransCanada to refile an application for the U.S. Presidential Permit (Presidential Permit), which we later filed with the DOS. In February 2017, we filed an application with the Nebraska PSC to seek approval for the Keystone XL pipeline route through the state. In March 2017, the DOS issued a Presidential Permit authorizing construction of the U.S./ Canada border crossing facilities of Keystone XL. We discontinued our claim under Chapter 11 of NAFTA and withdrew the U.S. Constitutional challenge. In March 2017, two lawsuits were filed in Montana District Court challenging the validity of the Presidential Permit. Along with the U.S. Government, we filed motions for dismissal of these lawsuits which were subsequently denied in November 2017. The cases will now proceed to the consideration of summary judgment motions. In July 2017, we launched an open season to solicit additional binding commitments from interested parties for transportation of crude oil on the Keystone pipeline and for Keystone XL from Hardisty, Alberta to Cushing, Oklahoma and the U.S. Gulf Coast, which concluded in October 2017. In November 2017, we received PSC approval for the alternative mainline route and we filed a motion with the PSC to reconsider its ruling and permit us to file an amended application that would support their decision and would address certain issues related to their selection of the alternative route, which was denied in December 2017. In December 2017, opponents of Keystone XL and intervenors in the Nebraska regulatory proceeding filed an appeal of the PSC decision seeking to have that decision overturned. TransCanada supports the decision of the PSC and will actively participate in the appeal process to defend that decision.
2018	We have secured commercial support for all available Keystone XL project capacity and commenced certain pre-construction activities. The Nebraska Supreme Court agreed to hear an appeal of the Nebraska PSC route approval, in which oral arguments were heard in November 2018. We expect the Nebraska Supreme Court, as the final arbiter, could reach a decision by first quarter 2019. The Presidential Permit was challenged in two separate lawsuits commenced in Montana. Together with the DOJ, we are actively participating in these lawsuits to defend both the issuance of the Presidential Permit and the exhaustive environmental assessments that support the U.S. President's actions. Legal arguments addressing the merits of these lawsuits were heard in second quarter 2018. In third quarter 2018, the U.S. District Court in Montana issued a Partial Order requiring the DOJ and the DOS (collectively, the Federal Defendants) to prepare a supplemental environmental impact statement (SEIS) to the 2014 Final SEIS. In fourth quarter 2018, the U.S. District Court Judge in Montana invalidated the Presidential Permit and granted a partial injunction on the Keystone XL project. We applied to the U.S. District Court for a stay of its various decisions affecting the issuance of the Presidential Permit and the extensive environmental assessments that have been done in support of its issuance.That stay application was heard on January 14, 2019 and we are awaiting a decision. We intend to further pursue a stay of these decisions with the Ninth Circuit Court of Appeals. Our plans to commence construction of the Keystone XL project in 2019 will be impacted by the timing and

Date	Description of development
2018 (continued)	outcome of our appeal and stay proceedings. In September 2018, two U.S. Native American communities filed a lawsuit in Montana challenging the Presidential Permit. We have been granted intervenor status in the lawsuits. Initial briefing dates have been established, but no further action has occurred. The South Dakota PUC permit for the Keystone XL project was issued in June 2010 and certified in January 2016. An appeal of that certification was denied in June 2017 and that decision was further appealed to the South Dakota Supreme Court. In June 2018, the Supreme Court dismissed the appeal against the certification of the Keystone XL project finding that the lower court lacked jurisdiction to hear the case. This decision is final as there can be no further appeals from this decision by the Supreme Court.
Energy East	
2016	In May 2016, we filed a consolidated application with the NEB for the Energy East pipeline. In June 2016, Energy East achieved a major milestone with the NEB's announcement determining the Energy East pipeline application was sufficiently complete to initiate the formal regulatory review process. However, in August 2016, panel sessions were canceled as three NEB panelists recused themselves from continuing to sit on the panel to review the project due to allegations of reasonable apprehension of bias. As a result, all hearings for the project were adjourned until further notice.
2017	In January 2017, the NEB appointed three new permanent panel members to undertake the review of the Energy East and Eastern Mainline projects, and subsequently voided all decisions made by the previous hearing panel members and removing such decisions from the official hearing record. We were not required to refile the application and parties were not required to reapply for intervener status. In September 2017, we requested the NEB suspend the review of the Energy East and Eastern Mainline project applications for 30 days to provide time for us to conduct a careful review of the NEB's changes, which were announced in August 2017. In October 2017, after careful review of the changed circumstances, we informed the NEB that we would not be proceeding with the Energy East and Eastern Mainline project applications. We also notified the MDDELCC that we were withdrawing the Energy East project from the environmental review process. As the Energy East pipeline was also to provide transportation services for the Upland pipeline, the DOS was notified in October 2017, that we would no longer be pursuing the U.S. Presidential Permit application for that project. We reviewed the $1.3 billion carrying value of the projects, including AFUDC capitalized since inception, and recorded a $954 million after-tax impairment charge in our fourth quarter 2017 results. We ceased capitalizing AFUDC on the projects effective August 23, 2017, the date of the NEB's announced scope changes. With Energy East's inability to reach a regulatory decision, no recoveries of costs from third parties are forthcoming.
Grand Rapids	
2016	Construction continued on the Grand Rapids pipeline. We entered into a partnership with Brion Energy Corporation (Brion) to develop Grand Rapids with each party owning 50 per cent of the pipeline project. Our partner has also entered into a long-term transportation service contract in support of the project. Construction progressed on the 20-inch diluent joint venture pipeline between Edmonton and Fort Saskatchewan, Alberta. The joint venture between Grand Rapids and Keyera was incorporated into Grand Rapids to provide enhanced diluent supply alternatives to our shippers.
2017	In August 2017, the Grand Rapids pipeline, jointly owned by TransCanada and PetroChina Canada Ltd. (formerly Brion), was placed in service. The 460 km (287 miles) crude oil transportation system connects producing area northwest of Fort McMurray, Alberta to terminals in the Heartland, Alberta market region.
Northern Courier	
2016	Construction continued on the Northern Courier pipeline, a 90 km (56 miles) pipeline system that transports bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta. The project is fully underpinned by long-term contracts with the Fort Hills partnership.
2017	The Northern Courier pipeline achieved commercial in-service in November 2017.
White Spruce	
2016	In December 2016, we finalized a long-term transportation agreement to develop and construct the 20-inch, 72 km (45 miles) White Spruce pipeline, which would transport crude oil from Canadian Natural Resources Limited's Horizon facility in northeast Alberta to the Grand Rapids pipeline.
2018	In February 2018, the AER issued a permit for the construction of the $200 million White Spruce pipeline. Construction has commenced with an anticipated in-service date in second quarter 2019.

Further information about developments in the Liquids Pipelines business, including changes that we can expect will occur in the current financial year, 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.

ENERGY

Development in the Energy Segment

Date	Description of development
CANADIAN POWER	
Alberta PPAs	
2016	In March 2016, we issued notice to the Balancing Pool to terminate our Alberta PPAs. In July 2016, we, along with the ASTC Power Partnership (ASTC), issued a notice referring the matter to be resolved by binding arbitration pursuant to the dispute resolution provisions of the PPAs. On July 25, 2016, the Government of Alberta brought an application in the Court of Queen's Bench to prevent the Balancing Pool from allowing termination of a PPA held by another party which contains identically worded termination provisions to our PPAs. In December 2016, management engaged in settlement negotiations with the Government of Alberta and finalized terms of the settlement of all legal disputes related to the PPA terminations. The Government of Alberta and the Balancing Pool agreed to our termination of the PPAs resulting in the transfer of all our obligations under such PPAs to the Balancing Pool. Upon final settlement of the PPA terminations, we transferred to the Balancing Pool a package of environmental credits held to offset the PPA emissions costs and recorded a non-cash charge of $92 million before-tax ($68 million after-tax) related to the carrying value of our environmental credits. In first quarter 2016, as a result of our decision to terminate the PPAs, we recorded a non-cash impairment charge of $240 million before-tax ($176 million after-tax) comprised of $211 million before-tax ($155 million after-tax) related to the carrying value of our Sundance A and Sheerness PPAs and $29 million before-tax ($21 million after-tax) on our equity investment in the ASTC which previously held the Sundance B PPA.
Napanee	
2018	Construction is substantially complete and commissioning activities are continuing at our 900 MW natural gas-fired power plant at Ontario Power Generation's Lennox site in eastern Ontario, in the town of Greater Napanee. We expect our total investment in the Napanee facility will be approximately $1.7 billion, with commercial operations expected to begin in second quarter 2019.
Cartier Wind	
2018	In October 2018, we completed the sale of our interests in the Cartier Wind power facilities in Québec to Innergex Renewable Energy Inc. for net proceeds of approximately $630 million, before post-closing adjustments, resulting in a gain of $170 million ($143 million after-tax).
Bécancour	
2016	In 2015, we executed an agreement with Hydro-Québec Distribution (HQ) allowing HQ to dispatch up to 570 MW of peak winter capacity from our Bécancour facility for a term of 20 years commencing in December 2016. The regulator in Québec, Régie de l'énergie, reversed its initial decision to approve this agreement. In November 2016, HQ released a new ten-year supply plan indicating additional peak winter capacity from Bécancour was not required. Management does not expect further developments at Bécancour until November 2019 when the next ten-year supply plan is filed.
Bruce Power	
2016	Bruce Power entered into an agreement with the IESO in 2015 to extend the operating life of the facility to the end of 2064. This new agreement represents an extension and material amendment to the earlier agreement that led to the refurbishment of Units 1 and 2 at the site. The amended agreement, which took effect on January 1, 2016, allows Bruce Power to immediately invest in life extension activities for Units 3 through 8. Beginning in January 2016, Bruce Power received a uniform price of $65.73 per MWh for all units, which included certain flow-through items such as fuel and lease expense recovery. Over time, the uniform price is subject to adjustments for the return of and on capital invested at Bruce Power under the asset management (AM) and major component replacement (MCR) programs, along with various other pricing adjustments that would allow for a better matching of revenues and costs over the long-term. In connection with this opportunity, we exercised our option to acquire an additional 14.89 per cent ownership interest in Bruce B for $236 million from the Ontario Municipal Employees Retirement System. Subsequent to this acquisition, Bruce A and Bruce B were merged to form a single partnership structure, of which we hold a 48.4 per cent interest.
2018	In September 2018, Bruce Power submitted its final cost and schedule duration estimate (basis of estimate) for the Unit 6 MCR program to the IESO. The IESO has verified the basis of estimate and the Unit 6 MCR program is scheduled to begin in early-2020 with an expected completion in late-2023. Our project cost estimates reflect our expected investment of approximately $2.2 billion (in nominal dollars) in Bruce Power's Unit 6 MCR program and its ongoing AM program through 2023 as well as approximately $6.0 billion (in 2018 dollars) for the remaining five-unit MCR program and the remainder of the AM program beyond 2023. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available for Bruce Power and the IESO. Bruce Power's current contract price of approximately $68 per MWh is expected to increase to approximately $75 per MWh on April 1, 2019 to reflect capital to be invested under the Unit 6 MCR program and the AM program as well as normal annual inflation adjustments.

Date	Description of development
Ontario Solar	
2017	In October 2017, we entered into an agreement to sell our Ontario solar assets comprised of eight facilities with a total generating capacity of 76 MW, to Axium Infinity Solar LP. On December 19, 2017, we closed the sale for $541 million, before post-closing adjustments, resulting in a gain of $127 million ($136 million after-tax).
Coolidge Generating Station	
2018	On December 14, 2018, we entered into an agreement to sell our Coolidge generating station in Arizona to SWG Coolidge Holdings, LLC for approximately US$465 million, subject to timing of closing and related adjustments. Salt River Project Agriculture Improvement and Power District, the PPA counterparty, exercised its contractual right of first refusal on a sale to a third party in January 2019. The sale will result in an estimated gain of approximately $65 million ($50 million after tax), to be recognized upon closing of the sale transaction which is expected to occur in mid-2019.
U.S. POWER	
Ironwood	
2016	In February 2016, we acquired the 778 MW Ironwood natural gas fired, combined cycle power plant located in Lebanon, Pennsylvania for US$653 million in cash after post-acquisition adjustments. The Ironwood power plant delivers energy into the PJM Interconnection area power market.
Monetization of U.S. Northeast Power Business	
2016	In November 2016, we announced the sale of Ravenswood, Ironwood, Ocean State Power and Kibby Wind to Helix Generation, LLC, an affiliate of LS Power Equity Advisors and the sale of TC Hydro to Great River Hydro, LLC, an affiliate of ArcLight Capital Partners, LLC.
2017	In April 2017, we closed the sale of TC Hydro to Great River Hydro, LLC for US$1.07 billion, before post-closing adjustments and recorded a gain of $715 million ($440 million after-tax). In June 2017, we closed the sale of Ravenswood, Ironwood, Ocean State Power and Kibby Wind to Helix Generation, LLC for US$2.029 billion, before post-closing adjustments. In addition to the pre-tax losses of approximately $829 million ($863 million after-tax) and a $1,085 million ($656 million after-tax) impairment charge that we recorded in 2016 upon entering into agreements to sell these assets, an additional pre-tax loss on sale of approximately $211 million ($167 million after-tax) was recorded in 2017, primarily related to an adjustment to the purchase price and repair costs for an unplanned outage at Ravenswood prior to close, partially offset by insurance recoveries for a portion of the repair costs. Proceeds from the sale transactions were used to fully retire the remaining bridge facilities that partially funded the acquisition of Columbia. On December 22, 2017, we entered into an agreement to sell our U.S. power retail contracts as part of the continued wind down of our U.S. power marketing operations.
2018	In March 2018, we closed the sale of our U.S. power retail contracts for proceeds of approximately US$23 million and recognized income of US$10 million (US$7 million after-tax).

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

Business of TransCanada

Our energy infrastructure business is made up of pipeline, storage and power generation assets that gather, transport, produce, store or deliver natural gas, crude oil and other petroleum products and electricity to support businesses and communities in North America.

Our vision is to be the leading energy infrastructure company in North America, focusing on pipeline and power generation opportunities in regions where we have or can develop a significant competitive advantage. Refer to the *About our business – 2018 Financial highlights, Consolidated results* section of the MD&A for our revenues from operations by segment, for the years ended December 31, 2018 and 2017, which section of the MD&A is incorporated by reference herein.

The following is a description of each of TransCanada'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 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. We also own and manage midstream assets that provide specific natural gas producer services including gathering, treatment, conditioning, processing and liquids handling with a focus on the Appalachian Basin.

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

The NGTL System, Canadian Mainline, and Foothills System (collectively, theSystems) are regulated by the NEB under the *National Energy Board Act* (Canada). The NEB regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for these Canadian regulated natural gas transmission systems.

The NEB approves tolls and services that provide TransCanada the opportunity to recover costs of transporting natural gas, including the return of capital (depreciation) and return on the average investment base for each of the Systems. Generally, Canadian natural gas pipelines request the NEB 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.

The NGTL System is operating under a two-year settlement arrangement for 2018-2019 with an incentive agreement with shippers providing a 50/50 sharing mechanism for any variance between fixed and actual OM&A costs. Further information relating to the 2018-2019 Settlement can be found in the *Natural Gas Pipelines – Developments in the Canadian Natural Gas Pipelines Segment* section above and in the *Canadian Natural Gas Pipelines – Significant Events, NGTL System* section of the MD&A, which section of the MD&A is incorporated by reference herein.

The Canadian Mainline is entering the fifth year of a six-year fixed toll settlement that includes an incentive arrangement where it has discretion to price certain of its short-term services, such as interruptible transportation, at market prices. Settlements of this nature provide the pipeline an incentive to either decrease costs and/or increase revenues on the pipeline with a beneficial sharing mechanism to both the shippers and TransCanada. In December 2018, the NEB approved the 2018-2020 tolls application as filed, except for the amortization of the LTAA. Further information relating to the NEB 2018 Decision can be found in the *Natural Gas Pipelines – Developments in the Canadian Natural Gas Pipelines Segment* section above and in the *Natural Gas Pipelines – Canadian Natural Gas Pipelines – Significant Events, Canadian Mainline* section of the MD&A, which section of the MD&A is incorporated by reference herein.

New facilities on or associated with the Systems are approved by the NEB before construction begins and the NEB regulates the operations of each of the Systems. Net earnings of the Systems may be affected by changes in investment base, the allowed ROE, the level of deemed common equity and any incentive earnings.

West Coast LNG – Natural Gas Pipeline Project

The Coastal GasLink natural gas pipeline project is being proposed and 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 NEB 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 and its shippers, and approved by the NEB. The Northern Courier and Grand Rapids pipelines are regulated by the AER. The AER regulates the construction and operation of pipelines and associated facilities in Alberta.

Liquids Pipelines Projects

The White Spruce pipeline is under development and is primarily under the regulatory regime administered by the AER. The AER administers approvals required to construct and operate the pipelines and associated facilities in accordance with *Directive 56*, approvals to obtain land access under the *Public Land Act* and environmental approvals under the *Environmental and Protection Enhancement Act*.

United States

Natural Gas Pipelines

TransCanada 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 *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, GTN and Portland 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 and Keystone XL pipelines, require a Presidential Permit from the DOS.

Mexico

Natural Gas Pipelines

TransCanada's pipelines in Mexico are regulated by the Comisión Reguladora de Energía who approve construction of new pipeline facilities and ongoing operations of the infrastructure. Our Mexican pipelines have approved tariffs, services and related rates; however, the contracts underpinning the construction and operation of the facilities are long-term negotiated fixed rate contracts.

These rates are only subject to change under specific circumstances such as certain types of force majeure events or changes in law.

ENERGY

Our Energy business consists of power generation and unregulated natural gas storage assets.

The power business includes approximately 6,600 MW of generation capacity that we currently either own or are developing. Our power generation assets are located in Alberta, Ontario, Québec, New Brunswick and Arizona, and are powered by natural gas and nuclear fuel sources. The majority of these assets are supported by long-term contracts.

We own and operate approximately 118 Bcf of unregulated natural gas storage capacity in Alberta and hold a contract with a third party for additional storage, in total accounting for approximately one-third of all storage capacity in the province.

On December 14, 2018, we entered into an agreement to sell our Coolidge Generating Station for approximately US$465 million.

Our U.S. power retail contracts were sold on March 1, 2018 as part of the continued wind-down of our U.S. Northeast power marketing business.

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

General

EMPLOYEES

At Year End, TransCanada's principal operating subsidiary, TCPL, had 7,081employees, substantially all of whom were employed in Canada and the U.S., as set forth in the following table.

Calgary (includes U.S. employees working in Canada)	2,646
Western Canada (excluding Calgary)	560
Eastern Canada	322
Houston (includes Canadian employees working in the U.S.)	801
U.S. Midwest	877
U.S. Northeast	257
U.S. Southeast/ Gulf Coast (excluding Houston)	1,240
U.S. West Coast	87
Mexico	291
Total	7,081

CORPORATE RESTRUCTURING AND BUSINESS TRANSFORMATION

In mid-2015, we commenced a business restructuring and transformation initiative to reduce overall costs and maximize the effectiveness and efficiency of our existing operations. For more information about our corporate restructuring and business transformation, refer to the *Corporate – Corporate restructuring and business transformation* section of the MD&A, which section of the MD&A is incorporated by reference herein.

HEALTH, SAFETY, SUSTAINABILITY AND ENVIRONMENTAL PROTECTION AND SOCIAL POLICIES

The Board's Health, safety, sustainability and environment (HSSE) Committee oversees operational risk, people and process safety, 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 which is used to capture, organize, document, monitor and improve our related policies, programs and procedures.

Our management system is modeled after international standards, conforms to external industry consensus standards and voluntary programs, and complies with applicable legislative requirements. It follows a continuous improvement cycle organized into four key areas:

- planning – risk and regulatory assessment, objective and target setting, defining roles and responsibilities
- implementing – development and implementation of programs, procedures and standards to manage operational risk
- reporting – incident reporting and investigation, and performance monitoring
- action – assurance activities and review of performance by management.

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

- overall HSSE corporate governance
- operational performance and preventative maintenance metrics
- asset integrity programs
- emergency preparedness, incident response and evaluation
- people and process safety performance metrics
- our Environment Program
- 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 related risks which may adversely impact TransCanada
- sustainability matters, including social, environmental and climate-change related matters
- management's approach to voluntary public disclosure on HSSE matters.

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 TransCanada 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 have a joint site visit annually.

Health and Safety

As one of TransCanada's 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 pipeline and energy infrastructure, is a top priority. All assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are placed in service only after all necessary requirements have been satisfied.

TransCanada annually conducts emergency response exercises to practice effective coordination between the Company, local emergency responders, regulatory agencies and government officials in the event of an emergency. TransCanada uses the Incident Command System which supports a unified approach to emergency response with these community members. TransCanada also provides annual training to all field staff in the form of table top exercises, online and vendor lead training.

Environmental risk, compliance and liabilities

We maintain an Environment Program to minimize potentially adverse environmental impacts. This program identifies our requirements to proactively and systematically manage environmental hazards and risks throughout the lifecycle of our assets.

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 to ensure compliance with all environmental requirements. We routinely monitor proposed changes in environmental policy, legislation and regulation, and 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

TransCanada has 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 TransCanada 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 Stakeholder Engagement Commitment Statement provides the structure to guide our teams' behavior and actions, so they understand their responsibility and extend respect, courtesy and the opportunity to respond to every stakeholder.

TransCanada's Aboriginal Relations and Native American Relations Policies are guided by principles of trust, respect and responsibility. We work together with Indigenous groups to find mutually acceptable solutions and benefits. These policies recognize the diversity and uniqueness of each Indigenous group, the importance of the land, and the imperative of building relationships based on mutual respect and trust.

TransCanada also has 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 strive for continuous improvement in how we navigate the interconnections and complexity of environmental, social and economic issues related to our business. These issues are of great importance to our stakeholders and Indigenous groups, and have an impact on our ability to build and operate energy infrastructure.

Risk factors

A discussion of our risk factors can be found in the MD&A in the *Natural Gas Pipelines – Business risks, Liquids Pipelines – Business risks, Energy – 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 TransCanada 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 TransCanada 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' 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 are issued to holders of the trust notes as a result of certain bankruptcy related events, TransCanada 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.

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 on our outstanding common shares per common share for the quarter ending March 31, 2019, are set out in the MD&A under the heading *About our business – 2018 financial highlights – Dividends*, which section of the MD&A is incorporated by reference herein.

Description of capital structure

SHARE CAPITAL

TransCanada'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 TransCanada 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 TransCanada 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 TransCanada upon a dissolution.

We have a shareholder rights plan that is designed to ensure, to the extent possible, that all shareholders of TransCanada 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 ten 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 TransCanada 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 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.

TransCanada has a dividend reinvestment and share purchase plan (DRP) under which eligible holders of common and preferred shares of TransCanada can reinvest their dividends to obtain additional TransCanada common shares. Common shares are currently issued from treasury at a discount of two per cent to market prices rather than purchased on the open markets to satisfy participation in the DRP. Participants may also make additional cash payments of up to $10,000 per quarter to purchase additional

common shares, which optional purchases are not eligible for any discount on the price of common shares. Participants are not responsible for payment of brokerage commissions or other transaction expenses for purchases made pursuant to the DRP.

TransCanada also has a stock based compensation plan that allows some employees to acquire common shares of TransCanada 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 TransCanada 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 TransCanada fails to pay dividends on that series of preferred shares for any period as may be so determined by the directors.

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 sixty-six and two thirds 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, 13 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 established 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 13 and 15 preferred shares, to a fixed minimum reset rate of 5.50 per cent and 4.90 per cent, respectively) and have the right to convert their shares into cumulative redeemable Series 2, 4, 6, 8, 10, 12, 14 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, 13 and 15 preferred shares are redeemable by TransCanada 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, 14 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, 13 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, 14 and 16 preferred shares are redeemable by TransCanada 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 TransCanada, the holders of Series 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 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, 2019 and every fifth year thereafter	1.92
Series 2 preferred shares	—	December 31, 2019 and every fifth year thereafter	1.92
Series 3 preferred shares	June 30, 2015	June 30, 2020 and every fifth year thereafter	1.28
Series 4 preferred shares	—	June 30, 2020 and every fifth year thereafter	1.28
Series 5 preferred shares	January 30, 2016	January 30, 2021 and every fifth year thereafter	1.54
Series 6 preferred shares	—	January 30, 2021 and every fifth year thereafter	1.54
Series 7 preferred shares	April 30, 2019	April 30, 2019 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, 2019 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 30, 2020 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	May 31, 2021	May 31, 2021 and every fifth year thereafter	4.69
Series 14 preferred shares	—	May 29, 2026 and every fifth year thereafter	4.69
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, or vote at any meeting of shareholders unless and until TransCanada 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 the 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 are junior to the first preferred shares with respect to the payment of dividends, repayment of capital and the distribution of assets of TransCanada in the event of a liquidation, dissolution or winding up of TransCanada.

Credit ratings

Although TransCanada Corporation 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 an issuer rating of Baa1 with a negative outlook, S&P has assigned a long-term corporate credit rating of BBB+ with a stable outlook, and Fitch has assigned a long-term corporate rating of A- with a stable outlook. TransCanada Corporation 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 our subsidiaries which have been rated by Moody's, S&P, Fitch and DBRS:

	Moody's	S&P	Fitch	DBRS
TCPL - Senior unsecured debt				
Debentures	A3	BBB+	A-	A (low)
Medium-term notes	A3	BBB+	A-	A (low)
TCPL - Junior subordinated notes	Baa1	BBB-	Not rated	BBB
TransCanada Trust - Subordinated trust notes	Baa2	BBB-	BBB	Not rated
TransCanada 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	Negative	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 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 were made to Moody's, S&P and DBRS in respect of other services provided in connection with the acquisition of Columbia.

The information concerning our credit ratings relates to our financing costs, liquidity and operations. The availability 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, TransCanada'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 A3 rating assigned to TCPL's senior unsecured debt is in the third highest of nine rating categories for long-term obligations. Obligations rated A are judged to be upper medium-grade and are subject to low credit risk. The P-2 rating assigned to TCPL's and TCPL-guaranteed U.S. commercial paper programs is the second highest of four rating categories for short-term debt issuers. Issuers rated P-2 have a strong ability to repay short-term debt obligations. The Baa1 rating assigned to TCPL's junior subordinated notes and the Baa2 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 1 as opposed to the modifier of 2 on the subordinated trust notes. Obligations rated Baa are judged to be medium-grade and are subject to moderate credit risk and, as such, may possess certain speculative characteristics.

S&P

S&P has different rating scales for short- and long-term obligations. Ratings from AA through CCC may be modified by the addition of a plus (+) or minus (-) sign to show the relative standing within a particular rating category. The BBB+ rating assigned to TCPL's senior unsecured debt is in the fourth highest of ten 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 ten rating categories for long-term debt obligations and the P-2(Low) rating assigned to TransCanada'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 TransCanada's preferred shares 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 eight 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 D 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 ten 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 F2 rating assigned to TCPL's and TCPL guaranteed commercial paper programs 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. The BBB rating assigned to the TransCanada Trust subordinated trust notes is in the fourth highest of ten rating categories for long-term debt obligations. The BBB ratings assigned to TransCanada's preferred shares and the TransCanada Trust subordinated trust notes indicate 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.

DBRS

DBRS has different rating scales for short- and long-term debt and 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 R-1 (low) rating assigned to TCPL's and TCPL guaranteed short-term debt is in the third highest of 10 rating categories and indicates good credit quality. The capacity for payment of short-term financial obligations as they fall due is substantial. 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. The A (low) rating assigned to TCPL's senior unsecured debt is in the third highest of 10 categories for long-term debt. Long-term debt rated A is good credit quality. The capacity for the payment of financial obligations is substantial, but of lesser credit quality than that of AA rated securities. 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. Long-term debt rated BBB is of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, but long-term debt rated BBB may be vulnerable to future events. The Pfd-2 (low) rating assigned to TransCanada's preferred shares is in the second highest of six rating categories for preferred shares. Preferred shares rated Pfd-2 are of satisfactory 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.

Market for securities

TransCanada'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 13 preferred shares	April 20, 2016	TRP.PR.J
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 TransCanada 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 2018	$56.06	$47.90	$48.75	56,220,000	$42.08	$34.58	$35.70	36,623,610
November 2018	$54.62	$49.98	$54.45	46,569,110	$41.15	$38.15	$40.92	32,349,090
October 2018	$54.23	$48.92	$49.64	50,660,000	$42.29	$37.24	$37.72	34,308,100
September 2018	$56.49	$52.06	$52.26	44,470,520	$42.92	$39.86	$40.46	19,278,150
August 2018	$59.27	$55.43	$55.58	36,470,000	$45.63	$42.48	$42.60	20,027,370
July 2018	$59.51	$56.09	$58.51	30,528,890	$45.09	$42.25	$44.95	20,225,410
June 2018	$58.50	$53.26	$56.88	45,610,000	$43.80	$41.14	$43.20	25,597,000
May 2018	$56.58	$53.61	$54.28	41,648,980	$44.05	$41.18	$41.83	38,214,990
April 2018	$56.40	$50.28	$54.44	39,940,000	$44.73	$39.16	$42.45	31,004,740
March 2018	$57.72	$51.63	$53.28	48,747,930	$44.65	$40.02	$41.31	34,601,117
February 2018	$58.75	$52.05	$55.50	40,890,194	$46.19	$41.24	$43.22	29,063,863
January 2018	$62.24	$55.67	$56.63	40,455,560	$49.89	$45.14	$46.04	28,858,757

TransCanada Corporate ATM Program

In June 2017, we established an ATM program that allows us to issue common shares from treasury from time to time, at the prevailing market price, when sold through the TSX, the NYSE, or any other existing trading market for TransCanada common shares in Canada or the United States. The ATM program, which is effective for a 25-month period, was initially established with an aggregate gross sales price of $1.0 billion or the U.S. dollar equivalent. In June 2018, we replenished the capacity available under our existing ATM program to allow the issuance of additional common shares from treasury having an aggregate gross sales price of up to $1.0 billion. The ATM program, as amended, is effective to July 23, 2019, and may be utilized at our discretion, if and as required, based on the spend profile of our capital program and relative cost of other funding options. Subsequent to issuances in 2017 and 2018 under the ATM program, an aggregate gross sales limit of $656 million or its US dollar equivalent remains available for issuance. Further information about the ATM program can be found in the *Financial condition – TransCanada's Corporate ATM Program*section of the MD&A, which section of the MD&A is incorporated by reference herein.

PREFERRED SHARES

	Preferred Shares										
Month	**Series 1**	**Series 2**	**Series 3**	**Series 4**	**Series 5**	**Series 6**	**Series 7**	**Series 9**	**Series 11**	**Series 13**	**Series 15**
December 2018											
High	$ 16.74	$ 17.00	$ 14.15	$ 14.29	$ 15.22	$ 16.19	$ 19.03	$ 20.20	$ 20.83	$ 25.96	$ 25.00
Low	$ 14.09	$ 14.69	$ 11.96	$ 11.99	$ 12.70	$ 13.22	$ 16.40	$ 16.78	$ 18.26	$ 25.15	$ 23.70
Close	$ 16.56	$ 16.70	$ 13.56	$ 13.93	$ 14.18	$ 14.22	$ 18.40	$ 18.72	$ 20.33	$ 25.41	$ 24.72
Volume traded	252,690	409,089	177,350	108,670	329,450	41,413	592,330	543,490	152,424	527,130	449,860
November 2018											
High	$ 19.80	$ 20.16	$ 16.99	$ 17.29	$ 17.44	$ 17.99	$ 22.13	$ 22.09	$ 23.77	$ 26.23	$ 25.94
Low	$ 16.50	$ 16.50	$ 14.01	$ 13.81	$ 14.55	$ 15.44	$ 18.65	$ 18.75	$ 19.86	$ 25.07	$ 24.37
Close	$ 16.50	$ 17.00	$ 14.08	$ 13.98	$ 14.99	$ 15.80	$ 18.79	$ 18.79	$ 20.40	$ 25.49	$ 24 85
Volume traded	115,846	85,858	95,340	310,853	372,220	24,776	191,709	168,174	127,440	647,000	293,860
October 2018											
High	$ 20.85	$ 21.30	$ 17.68	$ 17.84	$ 18.18	$ 18.98	$ 22.90	$ 23.04	$ 24.90	$ 26.53	$ 26.25
Low	$ 18.36	$ 18.56	$ 15.32	$ 15.76	$ 15.84	$ 16.75	$ 20.48	$ 20.25	$ 22.26	$ 25.38	$ 24.90
Close	$ 19.85	$ 19.46	$ 16.23	$ 16.69	$ 16.89	$ 17.32	$ 21.71	$ 21.71	$ 23.21	$ 26.17	$ 25.72
Volume traded	260,120	179,613	150,685	73,635	196,840	20,857	482,790	348,420	133,360	393,180	390,230
September 2018											
High	$ 20.71	$ 20.87	$ 17.55	$ 17.53	$ 17.95	$ 18.67	$ 23.05	$ 23.07	$ 24.49	$ 26.55	$ 26.15
Low	$ 20.18	$ 20.55	$ 16.85	$ 17.25	$ 17.32	$ 18.25	$ 22.34	$ 22.54	$ 24.23	$ 26.07	$ 25.58
Close	$ 20.69	$ 20.80	$ 17.49	$ 17.50	$ 17.62	$ 18.67	$ 22.69	$ 22.67	$ 24.38	$ 26.46	$ 26.08
Volume traded	109,148	37,300	43,974	33,110	363,720	6,210	158,110	133,770	110,587	85,649	240,590
August 2018											
High	$ 20.65	$ 20.89	$ 17.35	$ 17.51	$ 17.85	$ 18.63	$ 22.98	$ 22.89	$ 24.50	$ 26.62	$ 26.24
Low	$ 20.21	$ 20.36	$ 16.95	$ 17.15	$ 17.62	$ 18.11	$ 22.45	$ 22.39	$ 23.89	$ 26.04	$ 25.76
Close	$ 20.49	$ 20.80	$ 17.25	$ 17.47	$ 17.77	$ 18.63	$ 22.95	$ 22.70	$ 24.40	$ 26.30	$ 25.91
Volume traded	156,853	172,356	40,120	17,870	263,179	35,778	139,340	645,697	95,118	174,690	348,670
July 2018											
High	$ 20.78	$ 20.83	$ 17.31	$ 17.49	$ 17.99	$ 18.30	$ 22.99	$ 22.78	$ 24.59	$ 26.43	$ 25.92
Low	$ 20.24	$ 20.01	$ 16.74	$ 17.00	$ 17.50	$ 17.53	$ 22.42	$ 22.40	$ 23.93	$ 26.02	$ 25.38
Close	$ 20.36	$ 20.50	$ 17.14	$ 17.16	$ 17.63	$ 18.10	$ 22.80	$ 22.66	$ 24.19	$ 26.29	$ 25.78
Volume traded	51,108	705,451	243,087	43,329	287,284	15,777	214,720	815,601	130,962	381,440	493,660
June 2018											
High	$ 20.45	$ 20.25	$ 17.28	$ 17.00	$ 18.01	$ 18.45	$ 23.24	$ 23.21	$ 24.40	$ 26.26	$ 25.85
Low	$ 19.85	$ 19.96	$ 16.71	$ 16.72	$ 17.60	$ 17.99	$ 22.54	$ 22.31	$ 23.88	$ 25.83	$ 25.39
Close	$ 20.24	$ 20.05	$ 17.08	$ 16.84	$ 17.67	$ 18.06	$ 22.58	$ 22.49	$23.92	$ 26.24	$ 25.61
Volume traded	70,105	108,445	68,682	44,271	290,163	38,153	107,440	92,703	55,196	209,410	328,390
May 2018											
High	$ 20.80	$ 20.71	$ 17.25	$ 17.75	$ 18.07	$ 18.62	$ 23.66	$ 23.38	$ 24.62	$ 26.45	$ 26.15
Low	$ 19.69	$ 19.55	$ 16.45	$ 16.53	$ 17.27	$ 17.96	$ 22.33	$ 22.25	$ 23.55	$ 25.80	$ 25.39
Close	$ 20.15	$ 20.00	$ 16.80	$ 17.00	$ 17.77	$ 17.96	$ 22.65	$ 22.64	$ 23.97	$ 26.18	$ 25.78
Volume traded	238,030	377,217	325,450	38,170	701,502	18,932	669,200	557,091	86,608	506,560	661,240
April 2018											
High	$ 20.39	$ 20.30	$ 16.88	$ 16.97	$ 17.95	$ 19.02	$ 22.48	$ 22.39	$ 24.01	$ 26.47	$ 26.06
Low	$ 19.46	$ 19.50	$16.30	$ 16.29	$ 17.21	$ 18.09	$ 21.75	$ 21.80	$ 23.46	$ 26.15	$ 25.57
Close	$ 19.75	$ 19.73	$ 16.53	$ 16.60	$ 17.45	$ 18.30	$ 22.40	$ 22.20	$ 23.62	$ 26.29	$ 25.91
Volume traded	166,140	218,914	211,150	76,542	281,088	10,108	284,170	340,390	78,450	1,286,469	613,490
March 2018											
High	$ 20.89	$ 20.78	$ 17.26	$ 17.24	$ 18.15	$ 18.89	$ 23.70	$ 23.73	$24.37	$ 26.50	$ 26.05
Low	$ 20.24	$ 20.10	$ 16.61	$ 16.73	$ 17.70	$ 18.02	$ 22.08	$ 22.16	$23.72	$ 26.05	$ 25.43
Close	$ 20.49	$ 20.46	$ 16.95	$ 16.93	$ 17.99	$ 18.60	$ 22.20	$ 22.24	$23.90	$ 26.40	$ 26.05
Volume traded	200,698	71,565	125,455	58,736	82,615	15,500	239,180	227,894	169,419	375,189	400,078
February 2018											
High	$ 21.50	$ 21.67	$ 17.69	$ 17.64	$ 18.70	$ 18.89	$ 24.10	$ 24.34	$ 24.60	$ 26.62	$ 26.06
Low	$ 20.71	$ 20.73	$17.00	$ 17.13	$ 17.70	$ 18.05	$ 22.91	$ 23.15	$ 23.97	$ 25.86	$ 25.29
Close	$ 20.97	$ 20.77	$ 17.32	$ 17.27	$18.15	$ 18.34	$ 23.35	$ 23.42	$ 24.43	$ 26.25	$ 25.88
Volume traded	70,291	198,200	64,877	43,216	107,907	18,775	503,638	144,406	259,747	193,482	689,659
January 2018											
High						$ 19.53					
Low	$ 21.49	$ 21.15	$ 17.42	$ 17.59	$ 18.69	$ 16.93	$ 24.00	$ 24.56	$ 24.84	$ 26.84	$ 26.35
Close	$ 19.89	$ 19.31	$ 16.15	$ 15.74	$ 17.17	$ 18.60	$ 22.50	$ 23.23	$ 24.20	$ 26.40	$ 25.85
Volume traded	$ 20.96	$ 21.13	$ 17.18	$ 17.48	$ 18.30	26,970	$ 23.99	$ 24.31	$ 24.35	$ 26.53	$ 26.00
	161,053	70,146	213,388	37, 607	280,163		371,922	478,986	64,150	896,315	1,305,993

Directors and officers

As of February 13, 2019, the directors and officers of TransCanada as a group beneficially owned, or exercised control or direction over, directly or indirectly, an aggregate of 604,729 common shares of TransCanada. This constitutes less than one per cent of TransCanada's common shares. The Company collects this information from our directors and officers but otherwise we have no direct knowledge of individual holdings of TransCanada's securities.

DIRECTORS

The following table sets forth the names of the directors who serve on the Board as of February 13, 2019 (unless otherwise indicated), together with their jurisdictions of residence, all positions and offices held by them with TransCanada, their principal occupations or employment during the past five years and the year from which each director has continually served as a director of TransCanada and, prior to the Arrangement, with TCPL. Positions and offices held with TransCanada 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
Kevin E. Benson Calgary, Alberta Canada	Corporate director. Director, Winter Sport Institute (non-profit) from February 2015 to July 2018. Director, Calgary Airport Authority from January 2010 to December 2013.	2005
Stéphan Crétier Dubai, United Arab Emirates	Chairman, President and Chief Executive Officer, GardaWorld Security Corporation (GardaWorld) (private security services) and director of a number of GardaWorld's direct and indirect subsidiaries, since 1999.	2017
Russell K. Girling(1) Calgary, Alberta Canada	President and Chief Executive Officer, TransCanada since July 2010. Director, American Petroleum Institute since January 2015. Director, Nutrien Ltd. (formerly Agrium Inc.) (agriculture) since May 2006.	2010
S. Barry Jackson Calgary, Alberta Canada	Corporate director. Director, WestJet Airlines Ltd. (airline) since February 2009. Director, Laricina Energy Ltd. (Laricina) (oil and gas, exploration and production) from December 2005 to November 2017. Director, Nexen Inc. (Nexen) (oil and gas, exploration and production) from 2001 to June 2013, and Chair of the Board, Nexen from 2012 to June 2013.	2002
Randy Limbacher Houston, Texas U.S.A.	Chief Executive Officer, Meridian Energy, LLC (oil and gas exploration and production) since June 2017. Director, CARBO Ceramics Inc. since July 2007. President and Chief Executive Officer, Samson Resources Corporation (Samson) (oil and gas exploration and production) from April 2013 to December 2015. Vice Chairman and director, Samson Resources until March 2017.	2018
John E. Lowe Houston, Texas U.S.A.	Non-executive Chairman of the Board, Apache Corporation (Apache) (oil and gas) since May 2015. Director, Phillips 66 Company (energy infrastructure) since May 2012. Director, Apache since July 2013. Senior Executive Adviser at Tudor, Pickering, Holt & Co. LLC (energy investment and merchant banking) since September 2012. Director, Agrium Inc. (agriculture) from May 2010 to August 2015.	2015
Paula Rosput Reynolds Seattle, Washington U.S.A.	President and Chief Executive Officer, PreferWest, LLC (business advisory group) since October 2009. Director, CBRE Group, Inc. (commercial real estate) since March 2016. Director, BP p.l.c. (oil and gas) since May 2015. Director, BAE Systems plc. (aerospace, defence, information security) since April 2011. Director, Siluria Technologies Inc. (natural gas) from February 2015 to June 2017. Director, Delta Air Lines, Inc. (airline) from August 2004 to June 2015. Director, Anadarko Petroleum Corporation (oil and gas, exploration and production) from August 2007 to May 2014.	2011
Mary Pat Salomone Naples, Florida U.S.A.	Corporate director. Director, Herc Rentals (equipment rental) since July 2016. Director, Intertape Polymer Group (manufacturing) since November 2015. Senior Vice-President and Chief Operating Officer, The Babcock & Wilcox Company (energy infrastructure) from January 2010 to June 2013.	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 the Bank of Nova Scotia (Scotiabank) (chartered bank) since May 2008. Member, selection panel for Canada's outstanding chief executive officer. Member, The TriLateral Commission since August 2016.	2016
D. Michael G. Stewart Calgary, Alberta Canada	Corporate director. Director, Pengrowth Energy Corporation (oil and gas, exploration and production) since December 2010. Director, CES Energy Solutions Corp. (oilfield services) since January 2010. Director, Northpoint Resources Ltd. (oil and gas, exploration and production) from July 2013 to February 2015.	2006

Name and place of residence	Principal occupation during the five preceding years	Director since
Siim A. Vanaselja Toronto, Ontario Canada	Corporate director. Chair of the Board, TransCanada since May 2017. 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. Executive Vice-President and Chief Financial Officer, BCE Inc. and Bell Canada (telecommunications and media) from January 2001 to June 2015.	2014
Thierry Vandal Mamaroneck, New York U.S.A.	President, Axium Infrastructure US, Inc. (independent infrastructure fund management firm) and Director, Axium Infrastructure Inc. 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

Note:
(1) Effective June 13, 2018.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Except as indicated below, no other director or executive officer of the Corporation is or was a director, chief executive officer or chief financial officer of another company in the past ten years that:

- was the subject of a cease trade or similar order, or an order denying that company 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 acting 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.

Laricina voluntarily entered into the *Companies' Creditors Arrangement Act* (CCAA) and obtained an order from the Court of Queen's Bench of Alberta, Judicial Centre of Calgary for creditor protection and stay of proceedings effective March 26, 2015. A final court order was granted on January 28, 2016, allowing Laricina to exit from protection under the CCAA and concluding the stay of proceedings against Laricina and its subsidiaries. Mr. Jackson was a director of Laricina from December 2005 to November 2017.

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

On May 6, 2009, Crucible Materials Corp. (Crucible) and one of its affiliates filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the District of Delaware (the Bankruptcy Court). On August 26, 2010, the Bankruptcy Court entered an order confirming Crucible's Second Amended Chapter 11 Plan of Liquidation. Ms. Salomone was a director of Crucible from May 2008 to May 1, 2009.

No director or executive officer of the Corporation has within the past ten 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 Corporation 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

TransCanada has four committees of the Board: the Audit committee, the Governance committee, the Health, Safety, Sustainability & Environment committee and the Human Resources committee. As President and CEO of TransCanada, Mr. Girling 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 13, 2019 (unless otherwise indicated), 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 & Environment committee	Human Resources committee
Kevin E. Benson		Chair		ü
Stéphan Crétier	ü		ü	
S. Barry Jackson	ü			ü
Randy Limbacher	ü		ü	
John E. Lowe	Chair		ü	
Paula Rosput Reynolds		ü		Chair
Mary Pat Salomone		ü	ü	
Indira Samarasekera	ü			ü
D. Michael G. Stewart		ü	Chair	
Siim A. Vanaselja (Chair)		ü		ü
Thierry Vandal	ü		ü	

OFFICERS

With the exception of Stanley G. Chapman, III, all of the executive officers and corporate officers of TransCanada reside in Calgary, Alberta, Canada. Positions and offices held with TransCanada are also held by such person at TCPL. As of the date hereof, the officers of TransCanada, their present positions within TransCanada 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
Russell K. Girling	President and Chief Executive Officer	President and Chief Executive Officer.
Stanley G. Chapman, III	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. Prior to July 2016 Executive Vice-President and Chief Commercial Officer of Columbia Pipeline Group, Inc.
Kristine L. Delkus(1)	Executive Vice-President, Stakeholder Relations and General Counsel	Prior to February 1, 2019, Executive Vice-President, Stakeholder Relations and Technical Services and General Counsel. Prior to April 2017, Executive Vice-President, Stakeholder Relations and General Counsel. Prior to October 2015, Executive Vice-President, General Counsel and Chief Compliance Officer. Prior to March 2014, Senior Vice-President, Pipelines Law and Regulatory Affairs (TCPL).
Wendy L. Hanrahan	Executive Vice-President, Corporate Services	Executive Vice-President, Corporate Services.
Karl R. Johannson(2)	Executive Vice-President	Prior to January 1, 2019, Executive Vice-President and President, Canada and Mexico Natural Gas Pipelines and Energy. Prior to April 2017, Executive Vice-President, Natural Gas Pipelines.
Donald R. Marchand	Executive Vice-President and Chief Financial Officer	Prior to February 2017, Executive Vice-President, Corporate Development and Chief Financial Officer. Prior to October 2015, Executive Vice-President and Chief Financial Officer.
Paul E. Miller	Executive Vice-President, Technical Centre and President, Liquids Pipelines	Prior to February 1, 2019, Executive Vice-President and President, Liquids Pipelines. Prior to March 2014, Senior Vice-President, Oil Pipelines.
Francois L. Poirier	Executive Vice-President, Corporate Development and Strategy and President, Mexico Natural Gas Pipelines and Energy	Prior to January 1, 2019, Executive Vice-President, Strategy and Corporate Development. Prior to February 2017, Senior Vice-President, Strategy and Corporate Development. Prior to October 2015, President, Energy East Pipeline. Prior to September 2015, President, Wells Fargo Securities Canada, Ltd.
Tracy A. Robinson	Executive Vice-President and President, Canadian Natural Gas Pipelines	Prior to January 1, 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 (TCPL). Prior to April 2017, Senior Vice-President, Canada, Natural Gas Pipelines Division (TCPL). Prior to March 2017, Vice-President, Supply Chain (TCPL). Prior to October 2015, Vice-President, Transportation, Liquids Pipelines Division (TCPL). Prior to September 2014, Vice-President, Marketing and Sales, Canadian Pacific Railway Limited.

Notes:

(1) Ms. Delkus will be retiring from her role as Executive Vice-President, Stakeholder Relations and General Counsel in second quarter 2019.

(2) Mr. Johannson will be retiring from his role as Executive Vice-President on February 28, 2019.

Corporate officers

Name	Present position held	Principal occupation during the five preceding years
Gloria Hartl	Vice-President, Risk Management	Prior to February 1, 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 (Spectra). Prior to June 2014, General Manager, Tax (Spectra).
R. Ian Hendy	Vice-President and Treasurer	Prior to December 2017, Director, Financial Trading and Assistant Treasurer.
Joel E. Hunter	Senior Vice-President, Capital Markets	Prior to December 2017, Vice-President, Finance and Treasurer. Prior to August 2015, Vice-President, Finance.
Christine R. Johnston	Vice-President, Law and Corporate Secretary	Prior to June 2014, Vice-President and Corporate Secretary.
G. Glenn Menuz	Vice-President and Controller	Vice-President and Controller.

CONFLICTS OF INTEREST

Directors and officers of TransCanada and its subsidiaries are required to disclose any existing or potential conflicts in accordance with TransCanada policies governing directors and officers and in accordance with the CBCA. COBE covers potential conflicts of interest.

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 TransCanada'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 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 the 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 chief executive officer and executive vice-presidents (our executive leadership team) must receive the consent of the Governance committee. All other employees must receive the consent of the Corporate Secretary or her delegate.

Affiliates

The Board oversees relationships between TransCanada and any affiliates to avoid any potential conflicts of interest. This includes our relationship with TCLP, a master limited partnership listed on the NYSE.

Corporate governance

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

TransCanada 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 TSX and Canadian Securities Administrators:

- 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, except as summarized on our website (www.transcanada.com). 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.

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 13, 2019 are John E. Lowe (Chair), Stéphan Crétier, S. Barry Jackson, Randy Limbacher, Indira Samarasekera and Thierry Vandal. Mr. Jackson joined the committee effective April 27, 2018. On June 13, 2018, Mr. Limbacher was appointed as a director and became a member of the Audit committee.

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 Mr. Lowe 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 TransCanada, of each member of the Audit committee that is relevant to the performance of his responsibilities as a member of the Audit committee.

John E. Lowe (Chair)

Mr. Lowe holds a Bachelor of Science degree in Finance and Accounting from Pittsburg State University and is a Certified Public Accountant (inactive). He has been the non-executive Chairman of Apache Corporation's board of directors since May 2015. He also currently serves on the board of directors for Phillips 66 Company and has been the Senior Executive Adviser at Tudor, Pickering, Holt & Co. LLC since September 2012. Mr. Lowe has previously served on the audit committees for Agricum Inc. and DCP Midstream LLC. He has also held various executive and management positions with ConocoPhillips for more than 25 years.

Stéphan Crétier

Mr. Crétier earned a Master of Business Administration from the University of California (Pacific). He is the Chairman, President and CEO of a multinational corporation, Garda World, with over 20 years of experience in providing company-wide operational and financial oversight including monitoring the reporting and disclosure process. Mr. Crétier also serves as director of a number of Garda World’s direct and indirect subsidiaries. He previously served as a director of three public companies, ORTHOsoft Inc. (formerly ORTHOsoft Holdings Inc.), BioEnvelop Technologies Corp. and Rafale Capital Corp.

S. Barry Jackson

Mr. Jackson holds a Bachelor of Science degree in Engineering from the University of Calgary. He has been a director of WestJet Airlines Ltd. since February 2009. Mr. Jackson has also previously served as President and Chief Executive Officer of Crestar Energy Inc. and as director of Laricina, Nexen, Cordero Energy Inc., Resolute Energy Inc., Deer Creek Energy Limited, ENMAX Corporation, Westcoast Energy Inc., and Gulf Canada Resources Ltd.

Randy Limbacher

Mr. Limbacher holds a Bachelor of Science degree from Louisiana State University. He is currently the Chief Executive Officer of Meridian Energy, LLC. Mr. Limbacher also serves on the board of directors and audit committee for CARBO Ceramics Inc. and was previously the President and Chief Executive Officer and Vice Chairman of Samson. He has also served as Chairman, President and Chief Executive Officer of Rosetta Resources, Inc.

Indira Samarasekera

Dr. Samarasekera earned a Master of Science from the University of California and was granted a PhD in metallurgical engineering from the University of British Columbia. She also holds honorary degrees from the Universities of Alberta, British Columbia, Toronto, Waterloo, Montreal and Western in Canada and Queen's University in Belfast, Ireland. Dr. Samaraskera is currently a senior advisor for Bennett Jones LLP and serves on the board of directors of Scotiabank, Magna International Inc., Stelco Holdings Inc., and York House School. She is also a member of the TriLateral Commission and sits on the selection panel for Canada's outstanding chief executive officer of the year.

Thierry Vandal

Mr. Vandal earned a Masters of Business Administration in Finance from the École des Hautes Etudes Commerciales Montréal. He is the President of Axium Infrastructure US, Inc. and serves on the board of directors for Axium Infrastructure Inc. and on the international advisory board of École des Hautes Études Commerciale Montréal. He also serves on the board of directors for RBC where he is designated as RBC's audit committee's financial expert. Mr. Vandal previously served on the audit committee for Veresen Inc. until July 2017 and has over nine years' experience of serving with Hydro-Québec where he also held the position of President and Chief Executive Officer until May 2015.

PRE-APPROVAL POLICIES AND PROCEDURES

TransCanada'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 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 provided during the last two fiscal years and the fees we paid them:

($ millions)	2018	2017
Audit fees	$10.3	$9.7
• 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	$0.1	$0.1
• services related to the audit of the financial statements of TransCanada pipeline abandonment trusts and certain post-retirement plans		
Tax fees	$1.2	$0.8
• Canadian and international tax planning and tax compliance matters, including the review of income tax returns and other tax filings		
All other fees	$0.2	$0.2
• French translation services		
Total fees	**$11.8**	**$10.8**

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 potential or current proceeding or action to have a material impact on our consolidated financial position or results of operations.

Transfer agent and registrar

TransCanada's transfer agent and registrar is Computershare Trust Company of Canada with its Canadian transfer facilities in the cities of Vancouver, Calgary, Toronto, Halifax and Montréal.

Material contracts

TransCanada did not enter into any material contracts outside the ordinary course of business during the year ended December 31, 2018, nor has it entered into any material contracts outside the ordinary course of business prior to the year ended December 31, 2018 which are still in effect as at the date of this AIF.

Interest of experts

KPMG LLP are the auditors of TransCanada and have confirmed with respect to TransCanada, 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 TransCanada under all relevant U.S. professional and regulatory standards.

Additional information

1. Additional information in relation to TransCanada may be found under TransCanada's profile on SEDAR (www.sedar.com).
2. Additional information including directors' and officers' remuneration and indebtedness, principal holders of TransCanada's securities and securities authorized for issuance under equity compensation plans (all where applicable), is contained in TransCanada'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 TransCanada.
3. Additional financial information is provided in TransCanada's audited consolidated financial statements and MD&A for its most recently completed financial year.

Glossary

Units of measure

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

General terms and terms related to our operations

AM	asset management
ATM	An at-the-market distribution 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
Empress	A major delivery/receipt point for natural gas near the Alberta/ Saskatchewan border
FID	Final investment decision
FEIS	Final Environmental Impact Statement
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
MCR	major component replacement
PJM Interconnection area (PJM)	A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia
PPA	Power purchase arrangement
rate base	Average assets in service, working capital and deferred amounts used in setting of regulated rates
TSA	Transportation service agreements
WCSB	Western Canada Sedimentary Basin
Year End	Year ended December 31, 2018

Accounting terms

AFUDC	Allowance for funds used during construction
DRP	Dividend reinvestment plan
GAAP	U.S. generally accepted accounting principles
LTAA	Long Term Adjustment Account
OM&A	Operating, maintenance & administration
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*
CCAA	*Companies' Creditors Arrangement Act*
CFE	Comisión Federal de Electricidad (Mexico)
CPCN	Certificate of Public Convenience and Necessity
CQDE	Québec Environmental Law Centre/ Centre québécois du droit de l'environnement
DOJ	U.S. Department of Justice
DOS	U.S. Department of State
FERC	Federal Energy Regulatory Commission (U.S.)
IESO	Independent Electricity System Operator
HQ	Hydro-Québec Distribution
MDDELCC	Ministère du Développement durable, de l'Environnement et la Lutte contre les changements climatiques (Québec)
NAFTA	North American Free Trade Agreement
NEB	National Energy Board (Canada)
NRC	National Response Center
NYSE	New York Stock Exchange
OGC	Oil and Gas Commission (British Columbia)
PHMSA	Pipeline and Hazardous Materials Safety and Administration
PSC	Public Service Commission (Nebraska)
PUC	Public Utilities Commission (South Dakota)
SEC	U.S. Securities and Exchange Commission
SEIS	Supplemental environmental impact statement
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 (km)	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 recommend to the Board for approval, the release to the public of the Company's interim reports, including the consolidated financial statements, MD&A and press 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; and

(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;

(a) 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; and

(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; and

(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; and

(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; and

(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; and

(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 13, 2019

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TransCanada Corporation. It discusses our business, operations, financial position, risks and other factors for the year ended December 31, 2018.

This MD&A should be read with our accompanyingDecember 31, 2018 audited Consolidated financial statements and notes for the same period, which have been prepared in accordance with U.S. GAAP.

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About this document

Throughout this MD&A, the terms, *we*, *us*, *our* and *TransCanada* mean TransCanada Corporation and its subsidiaries. Abbreviations and acronyms that are not defined in the document are defined in the glossary on page 110. All information is as of February 13, 2019 and all amounts are in Canadian dollars, unless noted otherwise.

FORWARD-LOOKING INFORMATION

We disclose forward-looking information to help current and potential investors 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
- expected cash flows and future financing options available, including portfolio management
- expected dividend growth
- expected future credit ratings
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures and contractual obligations
- expected regulatory processes and outcomes, including the impact of the 2018 FERC Actions
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- the expected impact of future accounting changes, commitments and contingent liabilities
- expected industry, market and economic conditions.

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

- regulatory decisions and outcomes, including final outcomes of the 2018 FERC Actions
- planned and unplanned outages and the use of our pipeline and energy 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.

Risks and uncertainties

- 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 and energy assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the amount of capacity payments and revenues from our energy business due to plant availability
- production levels within supply basins
- construction and completion of capital projects
- costs for 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
- changes in environmental and other laws and regulations
- competition in the pipeline and energy sectors
- unexpected or unusual weather
- acts of civil disobedience
- cyber security and technological developments
- economic conditions in North America as well as globally
- our ability to effectively anticipate and assess changes to government policies and regulations.

You can read more about these factors 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 also find more information about TransCanada in our Annual Information Form (AIF) 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
- comparable distributable cash flow
- comparable distributable cash flow per common share.

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.

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 is subjective and made after careful consideration. Specific items may include:

- certain fair value adjustments relating to risk management activities
- income tax refunds and adjustments to enacted tax rates
- gains or losses on sales of assets or assets held for sale
- legal, contractual and bankruptcy settlements
- impact of regulatory or arbitration decisions relating to prior year earnings
- restructuring costs
- impairment of goodwill, investments and other assets including certain ongoing maintenance and liquidation costs
- acquisition and integration costs.

We exclude the unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain 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 reflective of our underlying operations.

The following table identifies our non-GAAP measures and their most directly comparable GAAP measures.

Non-GAAP 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
comparable funds generated from operations	net cash provided by operations
comparable distributable cash flow	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 EBIT represents segmented earnings adjusted for specific items. Comparable EBIT is an effective tool for evaluating trends in each segment. Refer to the Other information section for a reconciliation to segmented earnings.

Comparable earnings and comparable earnings per common share
Comparable earnings represents earnings or losses 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 taxes, non-controlling interests and preferred share dividends adjusted for specific items. Refer to the Financial highlights section for a reconciliation to net income attributable to common shares and net income per common share.

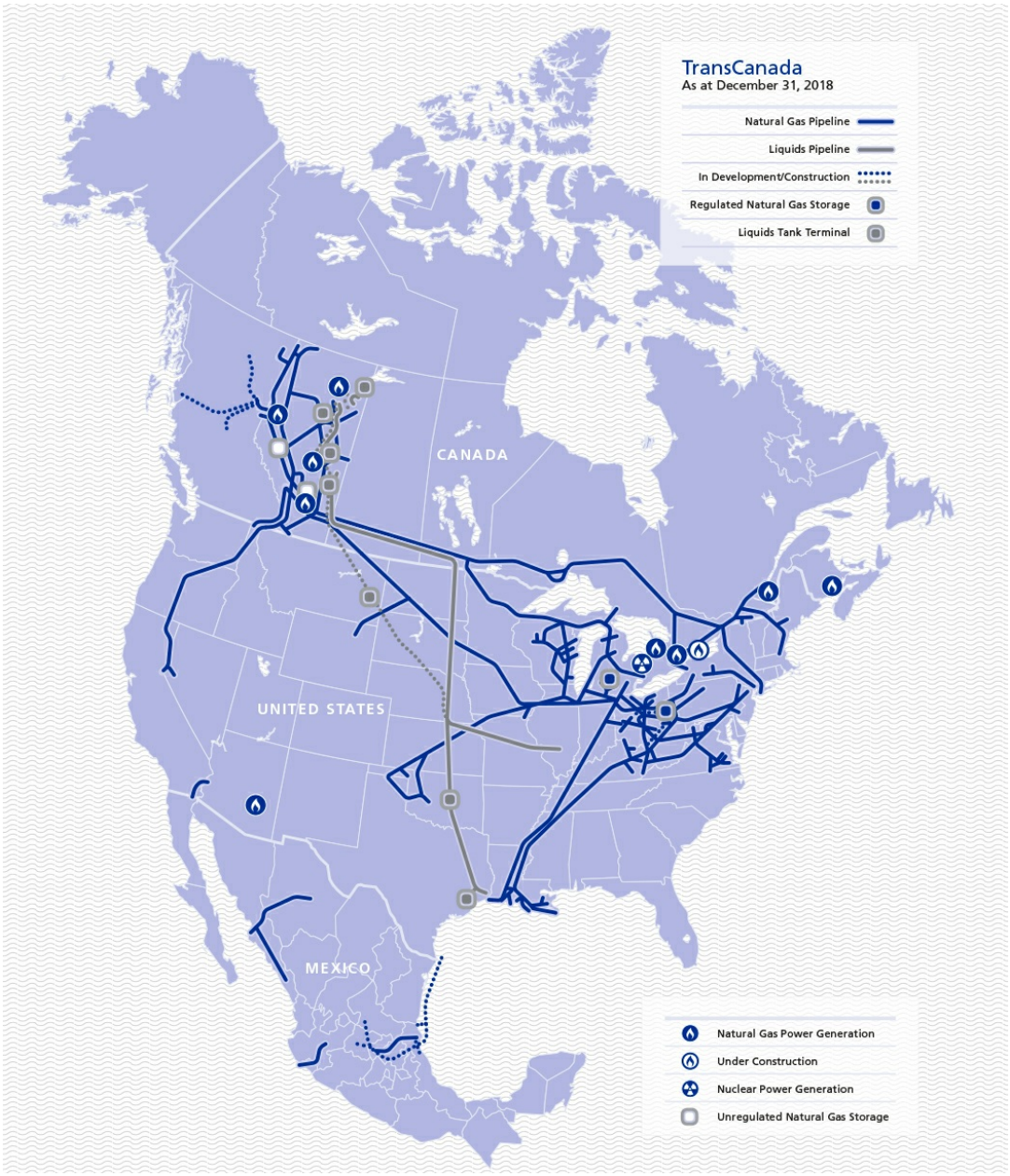
Funds generated from operations and comparable funds generated from operations
Funds generated from operations reflects net cash provided by operations before changes in operating working capital. We believe it is a useful measure of our consolidated operating cash flow because it does not include fluctuations 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 performance of our assets. 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.

Comparable distributable cash flow and comparable distributable cash flow per common share
We believe comparable distributable cash flow is a useful supplemental measure of performance that defines cash available to common shareholders before capital allocation. Comparable distributable cash flow is defined as comparable funds generated from operations less preferred share dividends, distributions to non-controlling interests and non-recoverable maintenance capital expenditures. Refer to the Financial condition section for a reconciliation to net cash provided by operations.

Maintenance capital expenditures are expenditures incurred to maintain our operating capacity, asset integrity and reliability, and include amounts attributable to our proportionate share of maintenance capital expenditures on our equity investments. We have the opportunity to recover effectively all of our pipeline maintenance capital expenditures in Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Liquids Pipelines through tolls. Canadian natural gas pipelines maintenance capital expenditures are included in rate bases, on which we earn a regulated return and subsequently recover in tolls. Our U.S. natural gas pipelines can recover maintenance capital expenditures through tolls under current rate settlements, or have the ability to recover such expenditures through tolls established in future rate cases or settlements. Tolling arrangements in our liquids pipelines provide for the recovery of maintenance capital expenditures. As such, in 2018 our presentation of comparable distributable cash flow and comparable distributable cash flow per common share only includes a reduction for non-recoverable maintenance capital expenditures in their respective calculations. We have adjusted our comparable distributable cash flow and comparable distributable cash flow per common share for 2017 and 2016 to reflect the amended presentation format which we believe provides better information for readers.

About our business

With over 65 years of experience, TransCanada 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 Energy. In order to provide information that is aligned with how management decisions about our businesses are made and how performance of our businesses are 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 Energy. We also have a Corporate segment, consisting of corporate and administrative functions that provide governance, financing and other support to the Company's business segments.

Year at a glance

at December 31 (millions of $)	2018	2017
Total assets by segment		
Canadian Natural Gas Pipelines	**18,407**	16,904
U.S. Natural Gas Pipelines	**44,115**	35,898
Mexico Natural Gas Pipelines	**7,058**	5,716
Liquids Pipelines	**17,352**	15,438
Energy	**8,475**	8,503
Corporate	**3,513**	3,642
	98,920	86,101

year ended December 31 (millions of $)	2018	2017
Total revenues by segment		
Canadian Natural Gas Pipelines	**4,038**	3,693
U.S. Natural Gas Pipelines	**4,314**	3,584
Mexico Natural Gas Pipelines	**619**	570
Liquids Pipelines	**2,584**	2,009
Energy[1]	**2,124**	3,593
	13,679	13,449

1 Includes Cartier Wind assets until sold in 2018 and U.S. Northeast power generation assets and Ontario solar assets until sold in 2017.

year ended December 31 (millions of $)	2018	2017
Comparable EBITDA by segment		
Canadian Natural Gas Pipelines	**2,379**	2,144
U.S. Natural Gas Pipelines	**3,035**	2,357
Mexico Natural Gas Pipelines	**607**	519
Liquids Pipelines	**1,849**	1,348
Energy[1]	**752**	1,030
Corporate	**(59)**	(21)
	8,563	7,377

1 Includes Cartier Wind assets until sold in 2018 and U.S. Northeast power generation assets and Ontario solar assets until sold in 2017.

Company Name Change

In January 2019, we announced our intention to change our name to TC Energy to better reflect the scope of our operations as a leading North American energy infrastructure company. Subject to shareholder and regulatory approval, the name change will be effective immediately following the Annual and Special Meeting of Shareholders on May 3, 2019.

OUR STRATEGY

Our energy infrastructure business is made up of pipeline, storage and power generation assets that gather, transport, produce, store or deliver natural gas, crude oil and other petroleum products and electricity to support businesses and communities in North America.

Our vision is to be the leading energy infrastructure company in North America, focusing on pipeline and power generation opportunities in regions where we have or can develop a significant competitive advantage.

Key components of our strategy at a glance

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

- Long-life infrastructure assets and long-term commercial arrangements are the cornerstones of our low risk business model
- Our pipeline assets include large-scale natural gas and crude oil pipelines that connect low cost supply basins with stable and growing markets, generating predictable and sustainable cash flow and earnings
- In Energy, long-term power sale agreements are used to manage and optimize our portfolio and to manage price volatility.

2 Commercially develop and build new asset investment programs

- We are developing high quality, long-life assets under our current $57 billion capital program, comprised of $36.6 billion in secured projects and $20.7 billion in largely commercially-supported projects under development. These investments will contribute incremental earnings and cash flows as they are placed in service
- Our expertise in project development, managing construction risks and maximizing capital productivity ensures a disciplined approach to reliability, cost and schedule, resulting in superior service for our customers and returns to shareholders
- As part of our growth strategy, we rely on this experience and our regulatory, commercial, financial, legal and operational expertise to successfully permit, fund, build and integrate new pipeline and other energy facilities
- We are able to balance safety, profitability and social and environmental responsibility in our investing activities.

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 and diversifies access to attractive supply and market regions
- We focus on pipeline and energy growth initiatives in core regions of North America and prudently manage development costs, minimizing capital-at-risk in early stages of projects
- We will advance selected opportunities to full development and construction when market conditions are appropriate and project risks and returns are acceptable
- We monitor trends in energy supply and demand, and maintain resilience through diversification, high quality cash flows and contractually underpinned assets.

4 Maximize our competitive strengths

- We are continually refining core competencies in areas such as safety, operational excellence, supply chain management, project execution and stakeholder relations to ensure we deliver maximum shareholder value over the short, medium and long terms.

Our Competitive Advantage

Decades of experience in the energy infrastructure business and a disciplined approach to project management and capital investment give us our competitive edge.

- strong leadership: operating capabilities and strategy development; expertise in regulatory, legal, commercial and financing support

- a high quality portfolio: scale, presence and a low-risk and enduring business model that maximizes the full-life value of our long-life assets and commercial positions throughout all points in the business cycle

- disciplined operations: 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 which are paramount parts of our core values

- financial positioning: consistently strong financial performance; long-term financial stability and profitability; disciplined approach to capital investment; ability to access sizable amounts of competitively priced capital to support our growth; simplicity and understandability of our business and corporate structure; ability to balance an increasing common share dividend while preserving financial flexibility to fund our capital program in all market conditions

- long-term relationships: long-term, transparent relationships with key customers and stakeholders; clear communication of our prospects to equity and fixed income investors – both the upside and the risks – to build trust and support.

Our Risk Preferences

The following is a discussion of our risk philosophy:

Live within our means

- Rely on internally-generated cash flows, existing debt capacity and portfolio management to finance new initiatives. Consider issuing new discrete common equity only for transformational opportunities, while the Corporate ATM program and DRP will be used as deemed appropriate.

Project risks known and acceptable

- 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 regulations and/or long-term contracts with creditworthy counterparties.

Value 'A' grade credit ratings

- 'A' grade ratings are an important competitive advantage and TransCanada will seek to retain existing ratings 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.

2018 FERC ACTIONS

Background

In December 2016, FERC issued a Notice of Inquiry (NOI) seeking comment on how to address the issue of whether its existing policies resulted in a 'double recovery' of income taxes in a pass-through entity such as an MLP. This NOI was in response to a decision by the U.S. Court of Appeals for the District of Columbia Circuit in July 2016 in United Airlines, Inc., et al. v. FERC (the United case), directing FERC to address the issue.

On December 22, 2017, H.R.1, the Tax Cuts and Jobs Act (U.S. Tax Reform), was signed resulting in significant changes to U.S. tax law including a decrease in the U.S. federal corporate income tax rate from 35 per cent to 21 per cent effective January 1, 2018. As a result, accumulated deferred income tax (ADIT) assets and liabilities related to our U.S. businesses, including amounts related to our proportionate share of assets held in TC PipeLines, LP, were remeasured as at December 31, 2017 to reflect the new lower U.S. federal corporate income tax rate. With respect to our U.S. rate-regulated natural gas pipelines and storage entities, the impact of this remeasurement was recorded as a net regulatory liability.

On March 15, 2018, FERC issued (1) a Revised Policy Statement to address the treatment of income taxes for rate-making purposes for MLPs; (2) a Notice of Proposed Rulemaking (NOPR) proposing natural gas pipeline and storage entities file a one-time report to quantify the impact of the federal income tax rate reduction and the impact of the Revised Policy Statement on each entity's ROE assuming a single-issue adjustment to an entity's rates; and (3) a NOI seeking comment on how FERC should address changes related to ADIT and bonus depreciation. On July 18, 2018, FERC issued (1) an Order on Rehearing of the Revised Policy Statement dismissing rehearing requests; and (2) a Final Rule adopting and revising procedures from, and clarifying aspects of, the NOPR (Final Rule), (collectively, the 2018 FERC Actions). The impacts of the Final Rule, which became effective September 13, 2018, relate to both FERC-regulated natural gas pipeline and gas storage assets. Discussion within this 2018 FERC Actions section primarily describes the impact to our natural gas pipelines, but also applies to our FERC-regulated natural gas storage assets.

FERC Revised Policy Statement on Treatment of Income Taxes for MLPs

The Revised Policy Statement changes FERC's long-standing policy allowing income tax amounts to be included in rates subject to cost-of-service rate regulation for pipelines owned by an MLP. The Revised Policy Statement creates a presumption that entities whose earnings are not taxed through a corporation should not be permitted to recover an income tax allowance in their regulated cost-of-service rates.

In the July 18, 2018 Order, FERC noted that an MLP is not automatically precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance in its cost-of-service rates. Additionally, FERC provided guidance with regards to ADIT for MLP pipelines and other pass-through entities. FERC found that, to the extent an entity's income tax allowance should be eliminated from rates, it must also eliminate its existing ADIT balance from its rate base. As a result, the Revised Policy Statement also precludes the recognition and subsequent amortization of any related regulatory assets or liabilities that might have otherwise impacted rates charged to customers as a refund or collection of excess or deficient deferred income tax assets or liabilities.

Final Rule on Tax Law Changes for Interstate Natural Gas Pipelines and Storage Entities

The Final Rule established a schedule by which interstate pipelines must either (i) file a new uncontested rate settlement or (ii) file a one-time report, called FERC Form 501-G (Form 501-G), that quantifies the isolated rate impact of U.S. Tax Reform on FERC-regulated pipelines and the impact of the Revised Policy Statement on pipelines held by MLPs. A pipeline filing a Form 501-G had to do so by established dates in fourth quarter 2018 and had four options:

1. Make a limited Natural Gas Act (NGA) Section 4 filing to reduce rates by the reduction in its cost-of-service shown in its Form 501-G. For any pipeline electing this option, FERC guarantees a three-year moratorium on NGA Section 5 rate investigations if the pipeline's Form 501-G shows the pipeline's estimated ROE as being 12 per cent or less. Under the Final Rule, and notwithstanding the Revised Policy Statement discussed above, a pipeline organized as an MLP is not required to eliminate its income tax allowance, but instead can reduce its rates to reflect the reduction in the federal corporate income tax rate. Alternatively, the MLP pipeline can eliminate its tax allowance along with its ADIT used for rate-making purposes. In situations where the ADIT balance is a liability, this elimination would have the effect of increasing the pipeline's rate base for rate-making purposes;
2. Commit to file either a pre-packaged uncontested rate settlement or a general Section 4 rate case if it believes that using the limited Section 4 option will not result in just and reasonable rates. For pipelines that committed to file either by December 31, 2018, FERC would not initiate a Section 5 investigation of its rates prior to that date;
3. File a statement explaining its rationale for why it does not believe the pipeline's rates must change; or
4. Take no other action. FERC will consider whether to initiate a Section 5 investigation of any pipeline that has not submitted a limited Section 4 rate filing or committed to file a general Section 4 rate case.

Impact of 2018 FERC Actions on TransCanada

In accordance with the Form 501-G filings for our directly-held U.S. natural gas pipelines, including ANR, Columbia Gas and Columbia Gulf, earnings and cash flows will not be materially impacted by the Revised Policy Statement as a significant proportion of their overall revenues are earned under non-recourse rates. Columbia Gas is required, under existing settlements, to adjust certain of its recourse rates for the decrease in the U.S. federal corporate income tax rate enacted December 22, 2017, with the changes implemented January 1, 2018. As ANR, Columbia Gas, Columbia Gulf and other wholly-owned regulated assets undergo future rate proceedings, future rates may be impacted prospectively as a result of U.S. Tax Reform, but the impact is expected to be largely mitigated by lower corporate income tax rates. The Revised Policy Statement also prohibits an income tax allowance for liquids pipelines held in MLP structures. We do not expect an impact on our U.S. liquids pipelines as they are not held in MLP form.

The following is an update on our filings in response to the Final Rule for our significant assets held outside of TC PipeLines, LP:

	Form 501-G Filing Option	Impact on Maximum Rates	Moratoriums and Mandatory Filing Requirements
Columbia Gas	Option 3	No rate change proposed	Moratorium in effect through January 31, 2022. Comeback provision with new rates effective by February 1, 2022
Columbia Gulf	Option 3	No rate change proposed	Moratorium in effect through June 30, 2019. Comeback provision with new rates effective by August 1, 2020
ANR	Option 3	No rate change proposed	Moratorium in effect through July 31, 2019. Comeback provision with new rates effective by August 1, 2022
ANR Storage	Option 3	No rate change proposed	No moratorium. Comeback provision with new rates effective by July 1, 2021
Millennium	Option 1 - filing accepted by FERC	10.3% reduction	No moratorium or comeback provisions
Crossroads	Option 3	No rate change proposed	No moratorium or comeback provisions

Impact of 2018 FERC Actions on TC PipeLines, LP

The following is an update on filings in response to the Final Rule for assets held by TC PipeLines, LP:

	Form 501-G Filing Option	Impact on Maximum Rates	Moratoriums and Mandatory Filing Requirements
Great Lakes	Option 1 - filing accepted by FERC	2.0% rate reduction effective February 1, 2019	No moratorium in effect. Comeback provision with new rates effective by October 1, 2022
GTN	Settlement approved by FERC on November 30, 2018 eliminating the requirement to file Form 501-G	A refund of US$10 million to its firm customers in 2018; a 10.0% reduction effective January 1, 2019; additional rate reduction of 6.6% effective January 1, 2020 through December 31, 2021	Moratorium on rate changes until December 31, 2021. Comeback provision with new rates effective by January 1, 2022
Northern Border	Option 1 - filing accepted by FERC	2.0% rate reduction effective February 1, 2019; additional 2.0% rate reduction effective January 1, 2020	No moratorium in effect. Comeback provision with new rates effective by July 1, 2024
Tuscarora	Option 1 - subsequently reached a settlement with customers and a notice of settlement-in-principle was filed with FERC on January 29, 2019	Expected to be finalized with the settlement	Expected to be finalized with the settlement
Bison	Option 3	No rate change proposed	No moratorium or comeback provisions
Iroquois	Option 3 - subsequently reached a settlement with customers and a notice of settlement-in-principle was filed with FERC on January 9, 2019	Expected to reduce rates by the impact of the lower U.S. federal tax rate as shown on Form 501-G	Likely to be reaffirmed with the settlement
Portland	Option 3	No rate change proposed	No moratorium or comeback provisions
North Baja	Option 1 - filing accepted by FERC	10.8% reduction effective December 1, 2018	No moratorium or comeback provisions

As a result of the 2018 FERC Actions initially proposed in March 2018, and in order to retain cash in anticipation of a possible reduction of revenues, TC PipeLines, LP reduced its quarterly distribution to common unitholders by 35 per cent to US$0.65 per unit beginning with its first quarter 2018 distribution.

Following the settlements and limited Section 4 filings for certain natural gas pipelines as noted above,TC PipeLines, LP's earnings, cash flows and financial position are less adversely impacted by the 2018 FERC Actions than initially expected. Furthermore, as our ownership in TC PipeLines, LP is approximately 25 per cent, the impact of the 2018 FERC Actions related to TC PipeLines, LP is not material to TransCanada's consolidated earnings or cash flows.

Financing

As a result of the initially proposed 2018 FERC Actions, we determined that further drop downs of assets into TC PipeLines, LP are not considered to be a viable funding lever. In addition, TC PipeLines, LP ceased to utilize its ATM program. It is yet to be determined whether these might be restored as competitive financing options. Regardless, we believe we have the financial capacity to fund our existing capital program through predictable and growing cash flow generated from operations, access to capital markets including through our DRP, portfolio management, cash on hand and substantial committed credit facilities.

Impairment Considerations

We review plant, property and equipment and equity investments for impairment whenever events or changes in circumstances indicate the carrying value of the asset may not be recoverable. Goodwill is tested for impairment on an annual basis, or more frequently if events or changes in circumstances indicate that it might be impaired. The filings noted above in response to the 2018 FERC Actions have been factored into the assumptions used in our annual goodwill impairment tests as well as our assessment of the recoverability of our long-lived asset balances. Refer to the Critical accounting estimates section for details on asset and goodwill impairments recorded in 2018.

IMPACT OF U.S. TAX REFORM

Pursuant to the enactment of U.S. Tax Reform, we adjusted our U.S. net ADIT liability balance at December 31, 2017 to reflect a decrease in the U.S. federal income tax rate from 35 per cent to 21 per cent. Amounts recorded to adjust income taxes remained provisional as our interpretation, assessment and presentation of the impact of U.S. Tax Reform was clarified during the one-year measurement period permitted by the SECwith additional guidance from tax authorities. In 2018, upon finalizing the 2017 annual tax returns for our U.S. businesses and clarifying the impact of U.S. Tax Reform on our deferred income tax liability at December 31, 2017, it was determined that an adjustment was required to the original estimate. Accordingly, a deferred income tax recovery of $52 million was recognized in fourth quarter 2018 to adjust our net regulatory liability and ADIT balances.

In addition to the adjustment noted above, the Final Rule resulting from the 2018 FERC Actions established that, to the extent an entity's income tax allowance should be eliminated from rates, it must also eliminate its existing ADIT balance from its rate base. In accordance with the Form 501-G and uncontested rate settlement filings summarized above, the ADIT balances for all pipelines held wholly or in part by TC PipeLines, LP were eliminated from their respective rate bases. As a result, net regulatory liabilities recorded for these assets pursuant to U.S. Tax Reform were written off, resulting in a further deferred income tax recovery of $115 million in fourth quarter 2018.

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 or regulated business models and are expected to generate significant growth in earnings and cash flows.

Our $57 billion capital program consists of approximately $36.6 billion of secured projects and approximately $20.7 billion of projects under development. Our secured projects include commercially supported, committed projects that are either under construction or are in or preparing to commence the permitting stage, but are not yet fully approved. Our projects under development are commercially supported except where noted, but have greater uncertainty with respect to timing and estimated project costs and are subject to certain approvals.

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 pipeline businesses 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.

All projects are subject to cost adjustments due to weather, market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits, among other factors. Amounts presented in the following tables exclude capitalized interest and AFUDC.

Secured projects

(billions of $)	Expected in-service date	Estimated project cost[1]	Carrying value at December 31, 2018
Canadian Natural Gas Pipelines			
Canadian Mainline	2019-2021	0.3	—
NGTL System	2019	2.8	1.4
	2020	1.7	0.2
	2021	2.8	—
	2022	1.3	—
Coastal GasLink[2,3]	2023	6.2	0.1
Regulated maintenance capital expenditures	2019-2021	1.8	—
U.S. Natural Gas Pipelines			
Columbia Gas			
Mountaineer XPress	2019	US 3.2	US 2.9
Modernization II	2019-2020	US 1.1	US 0.5
Columbia Gulf			
Gulf XPress	2019	US 0.6	US 0.5
Other capacity capital	2019-2022	US 0.9	US 0.1
Regulated maintenance capital expenditures	2019-2021	US 2.0	—
Mexico Natural Gas Pipelines			
Sur de Texas[4]	2019	US 1.5	US 1.4
Villa de Reyes[4]	2019	US 0.8	US 0.6
Tula[4]	2020	US 0.7	US 0.6
Liquids Pipelines			
White Spruce	2019	0.2	0.1
Other capacity capital	2020	0.1	—
Recoverable maintenance capital expenditures	2019-2021	0.1	—
Energy			
Napanee	2019	1.7	1.6
Bruce Power – life extension[5]	2019-2023	2.2	0.6
Other			
Non-recoverable maintenance capital expenditures[6]	2019-2021	0.7	0.2
		32.7	**10.8**
Foreign exchange impact on secured projects[7]		**3.9**	**2.4**
Total secured projects (Cdn$)		**36.6**	**13.2**

1 Amounts reflect our proportionate share of joint venture costs where applicable and 100 per cent of costs related to wholly-owned assets and assets held through TC PipeLines, LP.
2 Represents 100 per cent of required capital prior to potential joint venture partners or project financing.
3 Carrying value is net of fourth quarter 2018 receipts from the LNG Canada participants for the reimbursement of approximately $0.5 billion of pre-FID costs pursuant to project agreements. Refer to the Significant Events section in Canadian Natural Gas Pipelines for additional details.
4 The CFE has recognized force majeure events for these pipelines and approved the payment of fixed capacity charges in accordance with their respective TSAs. Payments will be recognized as revenue when the pipelines are placed in service.
5 Reflects our proportionate share of the Unit 6 Major Component Replacement program costs, expected to be in service in 2023, and amounts to be invested under the Asset Management program through 2023.
6 Includes non-recoverable maintenance capital expenditures from all segments and is primarily comprised of our proportionate share of maintenance capital expenditures for Bruce Power and other Energy assets.
7 Reflects U.S./Canada foreign exchange rate of 1.36 at December 31, 2018.

Projects under development

The costs provided in the table below reflect the most recent estimates for each project as filed with the various regulatory authorities or as otherwise determined by management.

(billions of $)	Estimated project cost[1]	Carrying value at December 31, 2018
Canadian Natural Gas Pipelines		
NGTL System – Merrick	1.9	—
Liquids Pipelines		
Keystone XL[2]	US 8.0	US 0.6
Heartland and TC Terminals[3]	0.9	0.1
Grand Rapids Phase II[3]	0.7	—
Keystone Hardisty Terminal[3]	0.3	0.1
Energy		
Bruce Power – life extension[4]	6.0	—
	17.8	**0.8**
Foreign exchange impact on projects under development[5]	**2.9**	**0.2**
Total projects under development (Cdn$)	**20.7**	**1.0**

1 Amounts reflect our proportionate share of joint venture costs where applicable.
2 Carrying value reflects amount remaining after impairment charge recorded in 2015, along with additional amounts capitalized from January 1, 2018.
3 Regulatory approvals have been obtained and additional commercial support is being pursued.
4 Reflects our proportionate share of Major Component Replacement program costs for Units 3, 4, 5, 7 and 8, and the remaining Asset Management program costs beyond 2023.
5 Reflects U.S./Canada foreign exchange rate of 1.36 at December 31, 2018.

2018 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 before interest, taxes, depreciation and amortization), comparable EBIT (comparable earnings before interest and taxes), comparable earnings, comparable earnings per common share, comparable funds generated from operations, comparable distributable cash flow and comparable distributable cash flow per common share are all non-GAAP measures. See page 8 for more information about the non-GAAP measures we use and pages 24, 75 and 102 for reconciliations to the most directly comparable GAAP measures.

year ended December 31 (millions of $, except per share amounts)	2018	2017	2016
Income			
Revenues	**13,679**	13,449	12,547
Net income attributable to common shares	**3,539**	2,997	124
per common share – basic	**$3.92**	$3.44	$0.16
– diluted	**$3.92**	$3.43	$0.16
Comparable EBITDA	**8,563**	7,377	6,647
Comparable earnings	**3,480**	2,690	2,108
per common share	**$3.86**	$3.09	$2.78
Cash flows			
Net cash provided by operations	**6,555**	5,230	5,069
Comparable funds generated from operations	**6,522**	5,641	5,171
Comparable distributable cash flow	**5,885**	4,963	4,482
Comparable distributable cash flow per common share	**$6.52**	$5.69	$5.91
Capital spending[1]	**10,929**	9,210	6,067
Acquisitions, net of cash acquired	**—**	—	13,608
Proceeds from sales of assets, net of transaction costs	**614**	4,683	6
Reimbursement of costs related to capital projects in development	**470**	634	—
Balance sheet			
Total assets	**98,920**	86,101	88,051
Long-term debt	**39,971**	34,741	40,150
Junior subordinated notes	**7,508**	7,007	3,931
Preferred shares	**3,980**	3,980	3,980
Non-controlling interests	**1,655**	1,852	1,726
Common shareholders' equity	**25,358**	21,059	20,277
Dividends declared[2]			
per common share	**$2.76**	$2.50	$2.26
Basic common shares (millions)			
– weighted average for the year	**902**	872	759
– issued and outstanding at end of year	**918**	881	864

1 Capital spending Includes capacity capital expenditures, maintenance capital expenditures, capital projects in development and contributions to equity investments.

2 Refer to the Financial condition section on page 74 for details on common and preferred share dividends.

Consolidated results

year ended December 31 (millions of $, except per share amounts)	2018	2017	2016
Segmented earnings/(losses)			
Canadian Natural Gas Pipelines	**1,250**	1,236	1,307
U.S. Natural Gas Pipelines	**1,700**	1,760	1,190
Mexico Natural Gas Pipelines	**510**	426	287
Liquids Pipelines	**1,579**	(251)	806
Energy	**779**	1,552	(1,157)
Corporate	**(54)**	(39)	(120)
Total segmented earnings	**5,764**	4,684	2,313
Interest expense	**(2,265)**	(2,069)	(1,998)
Allowance for funds used during construction	**526**	507	419
Interest income and other	**(76)**	184	103
Income before income taxes	**3,949**	3,306	837
Income tax (expense)/recovery	**(432)**	89	(352)
Net income	**3,517**	3,395	485
Net loss/(income) attributable to non-controlling interests	**185**	(238)	(252)
Net income attributable to controlling interests	**3,702**	3,157	233
Preferred share dividends	**(163)**	(160)	(109)
Net income attributable to common shares	**3,539**	2,997	124
Net income per common share			
–basic	**$3.92**	$3.44	$0.16
–diluted	**$3.92**	$3.43	$0.16

Net income attributable to common shares in 2018 was $3,539 million or $3.92 per share (2017 – $2,997 million or $3.44 per share; 2016 – $124 million or $0.16 per share). Net income per common share increased by $0.48 per share in 2018 compared to 2017 due to the changes in net income described below, as well as the dilutive impact of common shares issued in 2017 and 2018 under our DRP and Corporate ATM program.

The following specific items were recognized in net income attributable to common shares and were excluded from comparable earnings in the relevant periods:

2018

- a $143 million after-tax gain related to the sale of our interests in the Cartier Wind power facilities
- a $115 million deferred income tax recovery from an MLP regulatory liability write-off resulting from the 2018 FERC Actions
- a $52 million recovery of deferred income taxes as a result of finalizing the impact of U.S. Tax Reform
- a $27 million income tax recovery related to the sale of our U.S. Northeast power generation assets
- $25 million of after-tax income recognized on the Bison contract terminations
- a $140 million after-tax impairment charge on Bison
- a $15 million after-tax goodwill impairment charge on Tuscarora
- an after-tax net loss of $4 million related to our U.S. Northeast power marketing contracts. These were excluded from Energy's comparable earnings beginning in 2018 as the wind-down of these contracts is not considered part of our underlying operations.

2017

- an $804 million recovery of deferred income taxes as a result of U.S. Tax Reform
- a $307 million after-tax net gain on the monetization of our U.S. Northeast power generation assets
- a $136 million after-tax gain on the sale of our Ontario solar assets
- a $7 million income tax recovery related to the realized loss on a third party sale of Keystone XL project assets
- a $954 million after-tax impairment charge for the Energy East pipeline and related projects following our decision not to proceed with the project applications
- a $69 million after-tax charge for integration-related costs associated with the acquisition of Columbia
- a $28 million after-tax charge related to the maintenance and liquidation of Keystone XL assets.

2016

- an $873 million after-tax loss on U.S. Northeast power generation assets held for sale
- $28 million of income tax recoveries related to the realized loss on a third party sale of Keystone XL project assets
- $273 million of after-tax costs associated with the acquisition of Columbia
- an after-tax charge of $42 million for Keystone XL costs related to the maintenance and liquidation of project assets
- a $656 million after-tax impairment of Ravenswood goodwill
- a $244 million after-tax impairment charge on the carrying value and settlement of our Alberta PPAs
- an after-tax charge of $16 million for restructuring mainly related to expected future losses under lease commitments
- an additional $3 million after-tax loss on the sale of TC Offshore which closed in early 2016.

Refer to the Results section 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)	2018	2017	2016
Net income attributable to common shares	**3,539**	2,997	124
Specific items (net of tax):			
Gain on sale of Cartier Wind power facilities	**(143)**	—	—
MLP regulatory liability write-off	**(115)**	—	—
U.S. Tax Reform	**(52)**	(804)	—
Net (gain)/loss on sales of U.S. Northeast power generation assets	**(27)**	(307)	873
Bison contract terminations	**(25)**	—	—
Bison asset impairment	**140**	—	—
Tuscarora goodwill impairment	**15**	—	—
U.S. Northeast power marketing contracts	**4**	—	—
Gain on sale of Ontario solar assets	**—**	(136)	—
Keystone XL income tax recoveries	**—**	(7)	(28)
Energy East impairment charge	**—**	954	—
Integration and acquisition related costs – Columbia	**—**	69	273
Keystone XL asset costs	**—**	28	42
Ravenswood goodwill impairment	**—**	—	656
Alberta PPA terminations and settlement	**—**	—	244
Restructuring costs	**—**	—	16
TC Offshore loss on sale	**—**	—	3
Risk management activities[1]	**144**	(104)	(95)
Comparable earnings	**3,480**	2,690	2,108
Net income per common share	**$3.92**	$3.44	$0.16
Specific items (net of tax):			
Gain on sale of Cartier Wind power facilities	**(0.16)**	—	—
MLP regulatory liability write-off	**(0.13)**	—	—
U.S. Tax Reform	**(0.06)**	(0.92)	—
Net (gain)/loss on sales of U.S. Northeast power generation assets	**(0.03)**	(0.34)	1.15
Bison contract terminations	**(0.03)**	—	—
Bison asset impairment	**0.16**	—	—
Tuscarora goodwill impairment	**0.02**	—	—
U.S. Northeast power marketing contracts	**0.01**	—	—
Gain on sale of Ontario solar assets	**—**	(0.16)	—
Keystone XL income tax recoveries	**—**	(0.01)	(0.04)
Energy East impairment charge	**—**	1.09	—
Integration and acquisition related costs – Columbia	**—**	0.08	0.37
Keystone XL asset costs	**—**	0.03	0.06
Ravenswood goodwill impairment	**—**	—	0.86
Alberta PPA terminations and settlement	**—**	—	0.32
Restructuring costs	**—**	—	0.02
TC Offshore loss on sale	**—**	—	—
Risk management activities[1]	**0.16**	(0.12)	(0.12)
Comparable earnings per common share	**$3.86**	$3.09	$2.78

year ended December 31 (millions of $)	2018	2017	2016
Liquids marketing	**71**	—	(2)
Canadian Power	**3**	11	4
U.S. Power	**(11)**	39	113
Natural Gas Storage	**(11)**	12	8
Interest rate	**—**	(1)	—
Foreign exchange	**(248)**	88	26
Income taxes attributable to risk management activities	**52**	(45)	(54)
Total unrealized (losses)/gains from risk management activities	**(144)**	104	95

Comparable EBITDA to comparable earnings

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

year ended December 31 (millions of $)	2018	2017	2016
Comparable EBITDA	**8,563**	7,377	6,647
Adjustments:			
Depreciation and amortization	**(2,350)**	(2,048)	(1,939)
Interest expense included in comparable earnings	**(2,265)**	(2,068)	(1,883)
Allowance for funds used during construction	**526**	507	419
Interest income and other included in comparable earnings	**177**	159	71
Income tax expense included in comparable earnings	**(693)**	(839)	(841)
Net income attributable to non-controlling interests included in comparable earnings	**(315)**	(238)	(257)
Preferred share dividends	**(163)**	(160)	(109)
Comparable earnings	**3,480**	2,690	2,108

Comparable EBITDA and comparable earnings – 2018 versus 2017

Comparable EBITDA in 2018 increased by $1.2 billion compared to 2017 primarily due to the net result of the following:

- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes, and amortization of net regulatory liabilities recognized as a result of U.S. Tax Reform
- higher contribution from Liquids Pipelines primarily due to higher volumes on the Keystone Pipeline System, increased earnings from liquids marketing activities and earnings from intra-Alberta pipelines placed in service in the second half of 2017
- higher contribution from Canadian Natural Gas Pipelines primarily due to the recovery of increased depreciation as a result of higher rates approved in both the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as higher overall pre-tax rate base earnings, partially offset by lower incentive earnings and flow-through income taxes
- lower earnings from U.S. Power mainly due to the sales of our U.S. Northeast power generation assets in second quarter 2017
- lower earnings from Bruce Power primarily due to lower volumes resulting from higher outage days and lower results from contracting activities.

Comparable earnings in 2018 were $790 million or $0.77 per common share higher than in 2017, and were primarily the net result of:

- changes in comparable EBITDA described above
- higher depreciation primarily in Canadian Natural Gas Pipelines due to increased depreciation rates approved in the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement (these amounts are fully recovered as reflected in the increase in comparable EBITDA described above, having no net impact on comparable earnings) as well as higher depreciation related to new projects placed in service in 2017 and 2018
- higher interest expense primarily as a result of additional long-term debt issuances in 2018 and the full year impact of long-term debt and junior subordinated notes issuances in 2017, net of maturities, as well as lower capitalized interest, partially offset by the repayment of the Columbia acquisition bridge facilities in June 2017

- lower income tax expense primarily due to reduced income tax rates resulting from U.S. Tax Reform and lower flow-through income taxes in Canadian rate-regulated pipelines.

Comparable EBITDA and comparable earnings – 2017 versus 2016

Comparable EBITDA in 2017 increased by $730 million compared to 2016 primarily due to the net result of the following:

- higher contribution from U.S. Natural Gas Pipelines due to incremental earnings from Columbia following the July 1, 2016 acquisition and higher ANR transportation revenue resulting from a FERC-approved rate settlement effective August 1, 2016
- lower contribution from U.S. Power due to the monetization of our U.S. Northeast power generation assets in second quarter 2017 and the wind-down of our U.S. power marketing contracts
- increased earnings from Liquids Pipelines primarily due to higher uncontracted volumes on the Keystone Pipeline System, liquids marketing activities and the commencement of operations on Grand Rapids and Northern Courier
- higher earnings from Bruce Power mainly due to higher volumes resulting from fewer outage days
- higher contribution from Mexico Natural Gas Pipelines due to earnings from Topolobampo beginning in July 2016 and Mazatlán beginning in December 2016.

Comparable earnings in 2017 were $582 million or $0.31 per common share higher than in 2016, and were primarily the net result of:

- changes in comparable EBITDA described above
- higher interest expense as a result of debt assumed in the acquisition of Columbia on July 1, 2016 and long-term debt and junior subordinated notes issuances in 2017, net of maturities
- higher depreciation primarily from the Columbia acquisition in 2016 and projects placed in service
- higher AFUDC on our rate-regulated U.S. natural gas pipelines as well as on the NGTL System, Tula and Villa de Reyes, partially offset by the commercial in-service of Topolobampo and completion of Mazatlán construction
- higher interest income and other due to income related to the recovery of certain Coastal GasLink project costs and the termination of the Prince Rupert Gas Transmission (PRGT) project.

Comparable earnings per share in 2018 and 2017 were impacted by the dilutive impact of common shares issued under our DRP and Corporate ATM program, as well as the full-year impact in 2017 of the 2016 DRP and discrete equity issuances. Refer to the Financial condition section of this MD&A for further information on common share issuances.

Cash flows

Net cash provided by operations of $6.6 billion and comparable funds generated from operations of $6.5 billion were 25 per cent and 16 per cent higher, respectively, in 2018 compared to 2017, primarily due to higher comparable earnings, as described above. In addition, net cash provided by operations was affected by the amount and timing of working capital changes.

Comparable distributable cash flow, reflecting all non-recoverable maintenance capital expenditures, was $5.9 billion in 2018 compared to $5.0 billion in 2017, primarily due to higher comparable funds generated from operations. Comparable distributable cash flow per common share was also impacted by common share issuances in 2017 and 2018. Refer to the Financial condition section for more information on the calculation of comparable distributable cash flow.

Funds used in investing activities

Capital spending[1]

year ended December 31 (millions of $)	2018	2017	2016
Canadian Natural Gas Pipelines	**2,478**	2,181	1,525
U.S. Natural Gas Pipelines	**5,771**	3,830	1,522
Mexico Natural Gas Pipelines	**797**	1,954	1,142
Liquids Pipelines	**581**	529	1,137
Energy	**1,257**	675	708
Corporate	**45**	41	33
	10,929	9,210	6,067

1 Capital spending includes capacity capital expenditures, maintenance capital expenditures, capital projects in development and contributions to equity investments.

We invested $10.9 billion in capital projects in 2018 to optimize the value of our existing assets and to develop new, complementary assets in high demand areas. Our total capital spending in 2018 included contributions of $1.0 billion to our equity investments primarily related to Sur de Texas and Bruce Power. This amount was partially offset by $470 million of Coastal GasLink pre-FID costs that were reimbursed by LNG Canada joint venture participants in 2018.

In 2017, we invested $9.2 billion in capital projects to optimize the value of our existing assets and to develop new, complementary assets in high demand areas. Our total capital spending in 2017 included contributions of $1.7 billion to our equity investments primarily related to Sur de Texas, Bruce Power, Grand Rapids and Northern Border. This amount was partially offset by the reimbursement of $0.6 billion in project costs received on the termination of PRGT.

Proceeds from sales of assets

In 2018, we completed the sale of our interests in the Cartier Wind power facilities in Québec for net proceeds of $630 million, before post-closing adjustments.

In 2017, we completed the sales of TC Hydro, Ravenswood, Ironwood, Kibby Wind and Ocean State Power for net proceeds of US$3.1 billion, before post-closing adjustments. We also closed the sale of our Ontario solar assets for $541 million, before post-closing adjustments.

Balance sheet

We continue to maintain a solid financial position while growing our total assets by $12.8 billion in 2018. At December 31, 2018, common shareholders' equity represented 34 per cent (2017 – 33 per cent) of our capital structure, while other subordinated capital, in the form of junior subordinated notes and preferred shares, represented an additional 14 per cent (2017 – 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 8.7 per cent to $0.75 per common share for the quarter ending March 31, 2019 which equates to an annual dividend of $3.00 per common share. This was the 19th consecutive year we have increased the dividend on our common shares and reflects our commitment to growing our common dividend at an average annual rate of eight to ten per cent through 2021.

Dividend reinvestment plan

Under our DRP, eligible holders of common and preferred shares of TransCanada can reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares. Under this program, common shares are issued from treasury at a discount of two per cent to market prices over a specified period rather than purchased on the open markets to satisfy participation in the DRP.

Cash dividends paid

year ended December 31 (millions of $)	2018	2017	2016
Common shares	**1,571**	1,339	1,436
Preferred shares	**158**	155	100

OUTLOOK

Earnings

Our 2019 earnings, on a per common share basis, after excluding specific items, are expected to be higher than 2018 primarily due to the anticipated impact of the following:

- contributions from Columbia Gas and Columbia Gulf projects coming in service
- higher equity income from Bruce Power due to increased contract pricing
- growth in the average investment base for the NGTL System
- completion of the Napanee generating station
- commencement of operations on the Sur de Texas Pipeline.

Partially offset by:

- the dilutive impact of common shares issued in 2018 under our DRP and Corporate ATM Program and expected to be issued in 2019 under our DRP
- higher interest expense as a result of long-term debt issuances, net of maturities, and lower capitalized interest after placing assets in service
- the sale of our interests in the Cartier Wind power facilities
- the expected sale of our Coolidge generating station
- the uncertain impact of recent U.S. Tax Reform legislation and proposed regulations on the cost of financing certain of our U.S. operations.

Consolidated capital spending and equity investments

We expect to spend approximately $8 billion in 2019 on growth projects, maintenance capital expenditures and contributions to equity investments. The majority of the 2019 capital program is attributable to spending on NGTL System projects, Coastal GasLink, Columbia Gas Modernization II, Keystone XL development costs, the Bruce Power life extension program along with normal course maintenance capital expenditures. The above capital spend includes 100 per cent of the expected Coastal GasLink construction costs in 2019 which could be partially funded by the introduction of joint venture partners and project financing.

Refer to the relevant business segment outlook sections for additional details on earnings and capital spending for 2019.

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 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 – 81,500 km (50,500 miles); and
- partially-owned natural gas pipelines – 11,100 km (7,000 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. We also own and manage midstream assets that provide specific natural gas producer services including gathering, treatment, conditioning, processing and liquids handling with a focus on the Appalachian Basin.

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 at a glance

Optimizing the value of our existing natural gas pipeline systems, while responding to the changing flow patterns of natural gas in North America, is a top priority. We are also pursuing new pipeline opportunities to add incremental value to our business.

Our key areas of focus include:

- expansion and extension of our existing large 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 building development projects to provide connectivity to LNG export terminals on the west coast of Canada and the Gulf of Mexico
- connections to growing Canadian and U.S. shale gas and other supplies
- additional new pipeline developments within Mexico.

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

Highlights

Canadian Natural Gas Pipelines

- placed approximately $0.6 billion of projects in service
- announced four new expansion programs on our NGTL System totaling $4.1 billion with in-service dates between 2019 and 2022
- received an amending order and Certificate of Public Convenience and Necessity (CPCN) from the NEB approving construction of the North Montney Mainline facilities and guidance on related tolling matters
- received NEB approval on the NGTL 2018-2019 Revenue Requirement Settlement (2018-2019 Settlement), as filed
- received the NEB Decision on the Canadian Mainline 2018-2020 Tolls Application (NEB 2018 Decision) approving all elements of the filing except for the amortization period of the LTAA
- secured 670 TJ/d (625 MMcf/d) of new natural gas transportation contracts on the Canadian Mainline for North Bay Junction Long Term Fixed Price (NBJ LTFP) service from the WCSB to markets in Ontario, Québec, New Brunswick, Nova Scotia and the Northeastern U.S.
- proceeding with the estimated $6.2 billion Coastal GasLink pipeline project.

U.S. Natural Gas Pipelines

- placed in service in 2018 and early 2019 approximately US$5.8 billion of projects including Leach XPress, WB XPress, Cameron Access and partial in-service of Mountaineer XPress
- originated an additional US$0.5 billion of growth projects
- filed Form 501-Gs and uncontested rate settlements in response to the 2018 FERC Actions, which impacted rates for our U.S. natural gas pipelines and storage assets to varying degrees. Refer to the 2018 FERC Actions section for more detail.

Mexico Natural Gas Pipelines

- placed Topolobampo in operational service
- continued construction on our Sur de Texas, Villa de Reyes and Tula pipeline projects.

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 and end use markets. The network includes underground pipelines that transport natural gas predominantly under high pressure, compressor stations that act like pumps to move the 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 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 33 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 believe we are very well positioned to connect growing supply in northeast B.C. and northwest Alberta. Our large 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/B.C. 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 now provides supply to markets in Ontario,Québec, the Maritimes as well as the mid-west 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 fastest growing natural gas shale plays in North America. Similar to our footprint in the WCSB, our Columbia Gas assets are very 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 and south to the Gulf of Mexico and its growing demand for natural gas to serve LNG exports. Access to markets from producers in the region is driving the large capital program for new pipeline facilities on this system.

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 bi-directional capability on its Southeast Mainline and delivers gas produced from the Appalachian basin to customers throughout the Gulf Coast region.

Columbia Gulf: This pipeline system was originally designed as a long-haul delivery system transporting supply from the Gulf of Mexico to major demand markets in the U.S. Northeast. The pipeline has largely transitioned to a north-to-south flow and is expanding to accommodate new supply in the Appalachian Basin and from its interconnections with Columbia Gas and other pipelines to deliver gas to various Gulf Coast markets.

TC PipeLines, LP: We own a 25.5 per cent interest in TC PipeLines, LP, which has ownership interests in eight wholly-owned or partially-owned natural gas pipelines serving major markets in the U.S.

Mexico Natural Gas Pipelines

Mexico Pipeline Network: We have a growing network of natural gas pipelines coupled with a large portfolio of pipeline projects under construction in Mexico, including Tula and Villa de Reyes as well as Sur de Texas, of which we own 60 per cent.

Regulation of tolls and cost recovery

Our natural gas pipelines are generally regulated by the NEB in Canada, by FERC in the U.S. and by the CRE in Mexico. The regulators approve construction of new pipeline facilities and ongoing operations of the 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 recovered include OM&A, income and property taxes and interest on debt. The regulator reviews our costs to ensure they are reasonable and prudently incurred and approves 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, increasingly, 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 the two most prolific supply regions of North America, the WCSB and the Appalachian BasinOur pipelines also source natural gas, to a lesser degree, from other significant basins including the Rockies, Williston, Haynesville, Fayetteville and Anadarko 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 access to international markets via LNG exports. We expect North American natural gas demand, including LNG exports, of approximately 110 Bcf/d by 2020, reflecting an increase of approximately 10 Bcf/d from 2018 levels.

This expected increased demand for natural gas, coupled with the annual decline rate of 20 per cent to 25 per cent for natural gas production, implies over 35 Bcf/d of new supply connections being needed in the next two years, providing investment opportunities for pipeline infrastructure companies to build new facilities or increase utilization of the existing footprint.

Changing demand

The growing supply of natural gas has resulted in relatively low natural gas prices in North America, which has supported increased demand, particularly in the following areas:

- natural gas-fired electric-power generation
- petrochemical and industrial facilities
- Alberta oil sands
- exports to Mexico to fuel power generation facilities.

Natural gas producers have begun and continue to progress additional opportunities to sell natural gas to global markets which involves connecting natural gas supplies to LNG export terminals, both operating and proposed, along the U.S. Gulf Coast and the west coast of both the U.S. and Canada. The demand created by the addition of these new markets creates opportunities for us to build new pipeline infrastructure and to increase throughput on our existing pipelines.

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 fixed transportation costs 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. For example, lower natural gas prices have allowed this commodity to gain market share versus coal in serving power generation markets and to compete globally through LNG exports.

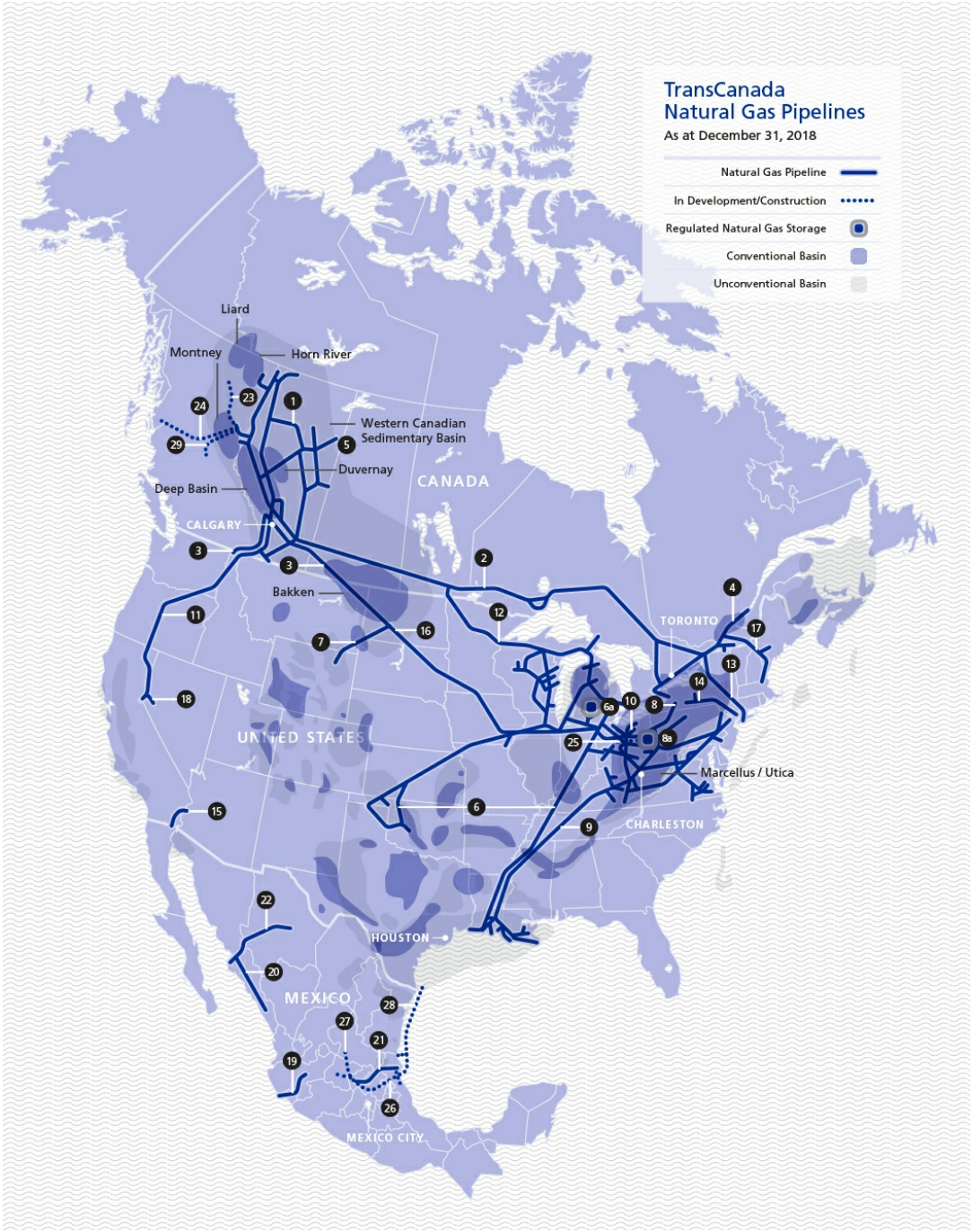
More competition

Changes in supply and demand levels and locations have resulted in increased competition for transportation services throughout North America. With our well-distributed footprint of natural gas pipelines, and particularly our new presence in the growing Appalachian region, we are well positioned to compete. Incumbent pipelines in an area benefit from owning existing right-of-way and infrastructure given the increasing challenges of siting and permitting for new pipeline construction and expansions. We have, and will continue to assess, further opportunities to restructure our tolls and service offerings to capture growing supply and North American demand that now includes access to world 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 the changing natural gas flow dynamics.

In 2019, some of our key focus areas will be the continued execution of our existing capital program that includes further expansion of the NGTL System, commencement of construction of Coastal GasLink, as well as the completion of several pipeline projects in the U.S. and in Mexico. Our goal is to place all of our projects in service on time and on budget while ensuring the safety of our staff, contractors and all stakeholders impacted by the construction and operation of these facilities.


TransCanada
Natural Gas Pipelines
As at December 31, 2018
Natural Gas Pipeline
In Development/Construction
Regulated Natural Gas Storage
Conventional Basin
Unconventional Basin
Liard
Montney
Horn River
Western Canadian Sedimentary Basin
Duvernay
Deep Basin
CALGARY
Bakken
CANADA
UNITED STATES
TORONTO
Marcellus / Utica
CHARLESTON
HOUSTON
MEXICO
MEXICO CITY

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

		Length	Description	Effective ownership
	Canadian pipelines			
1	NGTL System	24,568 km (15,266 miles)	Receives, transports and delivers natural gas within Alberta and B.C., and connects with the Canadian Mainline, Foothills system 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	1,241 km (771 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 the Portland pipeline system.	50%
5	Ventures LP	161 km (100 miles)	Transports natural gas to the oil sands region near Fort McMurray, Alberta. It also includes a 27 km (17 miles) pipeline supplying natural gas to a petrochemical complex at Joffre, Alberta.	100%
*	Great Lakes Canada	60 km (37 miles)	Transports natural gas from the Great Lakes system in the U.S. to a point near Dawn, Ontario through a connection at the U.S. border underneath the St. Clair River.	100%
	U.S. pipelines and gas storage assets			
6	ANR	15,075 km (9,367 miles)	Transports natural gas from various supply basins to markets throughout the U.S. Midwest and Gulf Coast.	100%
6a	ANR Storage	250 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key mid-western markets.	
7	Bison	488 km (303 miles)	Transports natural gas from the Powder River Basin in Wyoming to Northern Border in North Dakota. We effectively own 25.5 per cent of the system through our interest in TC PipeLines, LP.	25.5%
8	Columbia Gas	18,525 km (11,511 miles)	Transports natural gas from supply primarily in the Appalachian Basin to markets and pipeline interconnects throughout the U.S. Northeast.	100%
8a	Columbia Storage	285 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key eastern markets. We also own a 50 per cent interest in the 12 Bcf Hardy Storage facility.	100%
*	Midstream	295 km (183 miles)	Provides infrastructure between the producer upstream well-head and the downstream (interstate pipeline and distribution) sector and includes a 47.5 per cent interest in Pennant Midstream.	100%
9	Columbia Gulf	5,419 km (3,367 miles)	Transports natural gas to various markets and pipeline interconnects in the southern U.S. and Gulf Coast.	100%
10	Crossroads	325 km (202 miles)	Interstate natural gas pipeline operating in Indiana and Ohio with multiple interconnects to other pipelines.	100%
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. We effectively own 25.5 per cent of the system through our interest in TC PipeLines, LP.	25.5%
12	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. Upper Midwest. We effectively own 65.4 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 25.5 per cent interest in TC PipeLines, LP.	65.4%

		Length	Description	Effective ownership
13	Iroquois	669 km (416 miles)	Connects with the Canadian Mainline and serves markets in New York. We effectively own 13.2 per cent of the system through a 0.7 per cent direct ownership and our 25.5 per cent interest in TC PipeLines, LP.	13.2%
14	Millennium	407 km (253 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%
15	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. We effectively own 25.5 per cent of the system through our interest in TC PipeLines, LP.	25.5%
16	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. We effectively own 12.7 per cent of the system through our 25.5 per cent interest in TC PipeLines, LP.	12.7%
17	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. We effectively own 15.7 per cent of the system through our 25.5 per cent interest in TC PipeLines, LP.	15.7%
18	Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to markets in northeastern California and northwestern Nevada. We effectively own 25.5 per cent of the system through our interest in TC PipeLines, LP.	25.5%
	Mexico pipelines			
19	Guadalajara	310 km (193 miles)	Transports natural gas from Manzanillo, Colima to Guadalajara, Jalisco.	100%
20	Mazatlán	430 km (267 miles)	Transports natural gas from El Oro to Mazatlán, in the State of Sinaloa. Connects to the Topolobampo Pipeline at El Oro.	100%
21	Tamazunchale	370 km (230 miles)	Transports natural gas from Naranjos, Veracruz to Tamazunchale and on to El Sauz, Querétaro in central Mexico.	100%
22	Topolobampo	560 km (348 miles)	Transports natural gas to El Oro and Topolobampo, Sinaloa, from interconnects with third-party pipelines in El Encino, Chihuahua, and El Oro, Sinaloa.	100%
	Under construction			
	Canadian pipelines			
23	North Montney	206 km** (128 miles)	An extension of the NGTL System to receive natural gas from the North Montney gas producing region and connect to NGTL's existing Groundbirch Mainline.	100%
*	NGTL 2019 Facilities	160 km** (99 miles)	An expansion program on the NGTL System including multiple pipeline projects and compression additions with expected in-service dates by November 2019.	100%
24	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, B.C.	100%
	U.S. pipelines			
25	Mountaineer XPress - 45 per cent in-service in January 2019 (192 km or 119 miles)	275 km** (171 miles)	A Columbia Gas project designed to transport supply from the Marcellus and Utica shale plays to points along the system and to the Leach interconnect with Columbia Gulf.	100%

	Under construction (continued)	Length	Description	Effective ownership
	Mexico pipelines			
26	Tula	324 km** (201 miles)	The pipeline will originate in Tuxpan in the state of Veracruz, where it will receive natural gas from Sur de Texas and interconnect with Villa de Reyes at Tula to supply natural gas to CFE combined-cycle power generating facilities in central Mexico.	100%
27	Villa de Reyes	420 km** (261 miles)	This bi-directional pipeline will transport natural gas from Tula, Hidalgo to Villa de Reyes, San Luis Potosi, connecting to the Tamazunchale and Tula pipelines including a lateral to the Salamanca industrial complex in Guanajuato.	100%
28	Sur de Texas	775 km** (482 miles)	The pipeline will begin offshore in the Gulf of Mexico at the border near Brownsville, Texas with landfalls at Altamira, Tamaulipas and Tuxpan, Veracruz, connecting with the Tamazunchale and Tula pipelines and other third-party facilities.	60%
	Permitting and pre-construction phase			
	Canadian pipelines			
*	NGTL 2020 Facilities	120 km** (75 miles)	An expansion program on the NGTL System including multiple pipeline projects and compression additions with expected in-service dates by November 2020.	100%
*	NGTL 2021 Facilities	375 km** (233 miles)	An expansion program on the NGTL System including multiple pipeline projects and compression additions with expected in-service dates by November 2021.	100%
*	NGTL 2022 Facilities	197 km** (122 miles)	An expansion program on the NGTL System including multiple pipeline projects and compression additions with expected in-service dates by April 2022.	100%
	U.S. pipelines			
*	Buckeye XPress	103 km** (64 miles)	A Columbia Gas project designed to upgrade and replace existing pipeline and compression facilities in Ohio to transport incremental supply from the Marcellus and Utica shale plays to points along the system.	100%
	In development			
	Canadian pipelines			
29	Merrick Mainline	260 km** (161 miles)	To deliver natural gas from NGTL's existing Groundbirch Mainline near Dawson Creek, B.C. to its end point near the community of Summit Lake, B.C.	100%

* Facilities and some pipelines are not shown on the map.
** Final pipe lengths are subject to change during construction and/or final design considerations.

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 NEB has jurisdiction over our regulated Canadian natural gas interprovincial pipeline systems, while the provinces have jurisdiction over pipeline systems operating entirely within a single province. For the interprovincial pipelines it regulates, the NEB 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 costs to operate the pipeline is a return on the investment the company has 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 from debt. Typically, tolls are based on the cost of providing service 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 revenue 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 NEB.

We and our shippers can also establish settlement arrangements, subject to approval by the NEB, 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 in some fashion between the pipeline and shippers.

The NGTL System is operating under a two-year settlement arrangement for 2018-2019 with an incentive agreement with shippers providing a 50/50 sharing mechanism for any variance between fixed and actual OM&A costs. The Canadian Mainline is entering the fifth year of a six-year fixed toll settlement that includes an incentive arrangement where it has discretion to price certain of its short-term services, such as interruptible transportation, at market prices. Settlements of this nature provide the pipeline an incentive to either decrease costs and/or increase revenues on the pipeline with a beneficial sharing mechanism to both the shippers and us.

SIGNIFICANT EVENTS

Canadian Regulated Pipelines

Coastal GasLink Pipeline Project

In October 2018, we announced that we are proceeding with construction of the Coastal GasLink pipeline project following the LNG Canada joint venture participants' announcement that they had reached a positive FID to build the LNG Canada natural gas liquefaction facility in Kitimat, B.C. Coastal GasLink will provide the natural gas supply to the LNG Canada facility and is underpinned by 25-year TSAs (with additional renewal provisions) with each of the five LNG Canada participants. Coastal GasLink will be a 670 km (416 miles) pipeline with an initial capacity of approximately 2.2 PJ/d (2.1 Bcf/d) with potential expansion capacity up to 5.4 PJ/d (5.0 Bcf/d). All necessary regulatory permits have been received to allow us to proceed with construction activities which began in December 2018, with a planned in-service date in 2023. Coastal GasLink has signed project and community agreements with all 20 elected Indigenous bands along the pipeline route, confirming strong support from Indigenous communities across the province of B.C.

In July 2018, an individual asked the NEB to consider whether the Coastal GasLink pipeline should be federally regulated by the NEB. In October 2018, the NEB advised that it would consider the question of jurisdiction, granted Coastal GasLink standing in the matter, and reserved the right to decide on the participation of all other potentially interested parties, including the individual who raised the question. In December 2018, the NEB issued a process letter addressing participation and set the schedule which is expected to conclude in the second half of 2019, with a decision to follow.

In December 2018, the B.C. Supreme Court issued an interim injunction ordering opponents of the Coastal GasLink project to allow pipeline construction workers access to a blockaded area of the Coastal GasLink right of way, south of Houston, B.C. In January 2019, the RCMP moved to enforce the injunction. Following negotiations, the blockaders agreed to abide by the terms of the injunction and allow access to the area.

The Coastal GasLink capital cost estimate is $6.2 billion with the majority of the construction spend occurring in 2020 and 2021. Subject to terms and conditions, differences between the estimated capital cost and final cost of the project will be recovered in future pipeline tolls. As part of the Coastal GasLink funding plan, we are exploring joint venture partners and project financing.

The total capital cost includes pre-FID costs incurred of $470 million. In accordance with provisions in the agreements with the LNG Canada joint venture participants, all five parties elected to reimburse us for their share of pre-FID costs, totaling $470 million, in November 2018. In addition, in January 2019, all five partners elected to make cash payments throughout the construction period with respect to carrying charges on costs incurred.

NGTL System

2022 NGTL System Expansion Program

In October 2018, we announced the NGTL System 2022 Expansion Program to meet capacity requirements for incremental firm receipt and intra-basin delivery services to commence in November 2021 and April 2022. This $1.5 billion expansion of the NGTL System consists of approximately 197 km (122 miles) of new pipeline, three compressor units, meter stations and associated facilities. Applications for approvals to construct and operate the facilities are expected to be filed with the NEB in second quarter 2019 and, pending receipt of regulatory approvals, construction would start as early as third quarter 2020.

2021 NGTL System Expansion Program

In February 2018, we announced the NGTL System 2021 Expansion Program with an estimated capital cost of $2.3 billion and an anticipated in-service date in the first half of 2021. The program consists of approximately 375 km (233 miles) of new pipeline, three compressor units, a control valve and associated facilities. The expansion is required to connect incremental supply and expand basin export capacity by 1.1 PJ/d (1.0 Bcf/d) to the Empress export delivery point at the interconnection of the NGTL System and the Canadian Mainline. An application to construct and operate the NGTL System 2021 Expansion Program was filed with the NEB in June 2018 and will proceed through a public hearing in third quarter 2019.

North Montney Project Approval

In July 2018, the NEB issued an amending order and amended CPCN, following Federal government approval of our application, to the existing North Montney project approvals to remove the condition requiring a positive FID for the Pacific Northwest LNG project prior to commencement of construction.

The North Montney project consists of approximately 206 km (128 miles) of new pipeline, three compressor units and 14 meter stations. The current estimated project cost increased from original estimates by $0.2 billion to $1.6 billion mainly due to construction schedule delays and an increase in market-dependent construction costs.

The NEB directed NGTL to seek approval for a revised tolling methodology for the project following a provisional period defined as one year after the receipt of the Federal government decision, otherwise stand-alone tolling will be imposed as a default. NGTL is working with its shippers to address this requirement and is confident an acceptable tolling mechanism, other than stand-alone tolling, will be established.

Construction on the North Montney project was initiated in August 2018. The first phase of the project is anticipated to be in service by fourth quarter 2019 and the second phase by second quarter 2020.

Other Projects

In February 2019, we announced the Riverbend Extension project. This $85 million pipeline will connect the NGTL System to a proposed major industrial facility in the Grande Prairie, Alberta area. The project consists of approximately 28 km (17 miles) of NPS 24-inch pipeline and a delivery meter station, is underpinned by contracts for 330 TJ/d (308 MMcf/d) of incremental firm delivery service, and has an anticipated in-service date of third quarter 2021.

In April 2018, the Sundre Crossover project was placed in service. This $100 million pipeline project increases NGTL System capacity to our Alberta / B.C. export delivery point by approximately 245 TJ/d (228 MMcf/d), enhancing connectivity to key downstream markets in the Pacific Northwest and California.

In April 2018, the Northwest Mainline Loop-Boundary Lake project was placed in service. The $160 million project added approximately 230 km (143 miles) of new pipeline along with compression facilities and increased the NGTL System capacity by approximately 535 TJ/d (500 MMcf/d).

In March 2018, we announced the successful completion of an open season for additional expansion capacity at the Empress / McNeill Export Delivery Point for service expected to commence in November 2021. The offering of 300 TJ/d (280 MMcf/d) was oversubscribed, with an average awarded contract term of approximately 22 years. The facilities and capital requirements for the expansion are estimated to be approximately $140 million.

NGTL 2018-2019 Revenue Requirement Settlement Approval

In June 2018, the NEB approved the 2018-2019 Settlement as filed and the resulting final 2018 tolls. The 2018-2019 Settlement, which is effective from January 1, 2018 to December 31, 2019, fixes ROE at 10.1 per cent on 40 per cent deemed common equity and increases the composite depreciation rate from 3.18 per cent to 3.45 per cent. OM&A costs are fixed at $225 million for 2018 and $230 million for 2019 with a 50/50 sharing mechanism for any variances between the fixed amounts and actual OM&A costs. All other costs, including pipeline integrity expenses and emissions costs, are treated as flow-through expenses.

Canadian Mainline

North Bay Junction Long Term Fixed Price

In December 2018, we announced 670 TJ/d (625 MMcf/d) of new natural gas transportation contracts from the WCSB on the Canadian Mainline. Upon NEB approval of the NBJ LTFP service, incremental volumes under these long-term, fixed-priced contracts will reach markets in Ontario, Québec, New Brunswick, Nova Scotia and the Northeastern U.S. using existing capacity on the Canadian Mainline as well as new compression facilities. Customers have executed 15-year precedent agreements to proceed with the project with an estimated capital cost of $96 million. We filed an application for approval of the NBJ LTFP with the NEB in January 2019 and expect a decision in third quarter 2019.

Canadian Mainline 2018-2020 Toll Review

In October 2018, we concluded the written hearing process for the Canadian Mainline 2018-2020 toll review with the filing of our reply evidence to the NEB. In December 2018, the NEB 2018 Decision was issued approving all elements of the application, including our cost and volume forecasts, higher depreciation rates and continuation of pricing discretion, with the exception of the amortization period for the LTAA, which is now to be amortized over 2018 to 2020. The impact of the decision was reflected in lower tolls effective February 1, 2019. As directed by the NEB, we filed a compliance filing in January 2019, the outcome of which is expected in first quarter 2019.

Maple Compressor Expansion Project

In April 2018, we received NEB approval to proceed with construction of this approximate $110 million new compressor unit. Work continues as planned to meet a November 1, 2019 in-service date.

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). See page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2018	2017	2016
NGTL System	**1,197**	996	968
Canadian Mainline	**1,073**	1,043	1,105
Other Canadian pipelines[1]	**109**	105	109
Comparable EBITDA	**2,379**	2,144	2,182
Depreciation and amortization	**(1,129)**	(908)	(875)
Comparable EBIT and segmented earnings	**1,250**	1,236	1,307

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

Canadian Natural Gas Pipelines comparable EBIT and segmented earnings increased by $14 million in 2018 compared to 2017 and decreased by $71 million in 2017 compared to 2016.

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 revenue on a flow-through basis.

Net Income and Average Investment Base

year ended December 31 (millions of $)	2018	2017	2016
Net income			
NGTL System	**398**	352	318
Canadian Mainline	**182**	199	208
Average investment base			
NGTL System	**9,669**	8,385	7,451
Canadian Mainline	**3,828**	4,184	4,441

Net income for the NGTL System was $46 million higher in 2018 compared to 2017 mainly due to a higher average investment base as a result of continued system expansions. NGTL System net income in 2017 was $34 million higher than 2016 due to a higher average investment base, partially offset by higher carrying charges on regulatory deferrals. The two-year 2016-2017 Revenue Requirement Settlement included an ROE of 10.1 per cent on 40 per cent deemed common equity and a mechanism for sharing variances above and below a fixed annual OM&A amount.

Canadian Mainline's net income in 2018 decreased by $17 million compared to 2017 mainly due to a lower average investment base and lower incentive earnings, partially offset by lower carrying charges to shippers on the 2018 net revenue surplus. Net income in 2017 was $9 million lower than 2016 mainly due to a lower average investment base and higher carrying charges to shippers on the 2017 net revenue surplus, partially offset by higher incentive earnings in 2017. The lower average investment base in 2018 and 2017 was mainly due to depreciation and the inclusion of the 2017 and 2016 net revenue surplus deferrals in investment base.

The Canadian Mainline operated under the 2015-2030 Tolls Application approved in 2014 (NEB 2014 Decision) throughout 2015 to 2018. The NEB 2014 Decision included an approved ROE of 10.1 per cent with a possible range of achieved ROE outcomes between 8.7 per cent and 11.5 per cent. This decision also included an incentive mechanism that has both upside and downside risk and a $20 million annual after-tax contribution from us. Toll stabilization is achieved through the continued use of deferral accounts to capture the surplus or shortfall between our revenues and cost of service for each year over the six-year fixed toll term from 2015 to 2020.

The NEB 2014 Decision also directed us to file an application to review tolls for the 2018-2020 period. In December 2018, the NEB 2018 Decision was received 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. See the Significant events section for additional details on the NEB 2018 Decision.

Comparable EBITDA

Comparable EBITDA for Canadian Natural Gas Pipelines was $235 million higher in 2018 compared to 2017 primarily due to the recovery of increased depreciation as a result of higher rates approved in both the Canadian Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as higher overall pre-tax rate base earnings, partially offset by lower incentive earnings and flow-through income taxes. Comparable EBITDA for Canadian Natural Gas Pipelines in 2017 was consistent with 2016.

Depreciation and amortization

Depreciation and amortization was $221 million higher in 2018 compared to 2017 due to the increase in depreciation rates approved in the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as NGTL System facilities that were placed in service in 2018. Depreciation and amortization was $33 million higher in 2017 compared to 2016 primarily due to NGTL System facilities that were placed in service in both 2017 and 2016.

OUTLOOK

Earnings

Net income for Canadian rate-regulated pipelines is affected by changes in investment base, ROE and regulated capital structure, as well as by the terms of toll settlements approved by the NEB.

Canadian Natural Gas Pipelines earnings in 2019 are expected to be higher than 2018 mainly due to continued growth in the NGTL System. We expect the NGTL System investment base to continue to increase as we extend and expand the northwest supply facilities, northeast and intra-Alberta delivery facilities and incremental service at our major border delivery locations in response to requests for firm service on the system.

We expect earnings from the Canadian Mainline to be slightly lower in 2019 due to lower incentive earnings. We were directed by the NEB 2018 Decision to accelerate the amortization of the LTAA over the 2018 to 2020 period, which effectively reduces the tolls and revenues in those years, but has no significant impact on net income.

We also anticipate a modest level of investment in our other Canadian rate-regulated natural gas pipelines, but expect the average investment bases of these systems to continue to decline as annual depreciation outpaces capital investment, reducing their year-over-year earnings.

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.

Capital spending

We spent a total of $2.5 billion in 2018 on our Canadian natural gas pipelines and expect to spend approximately $3.1 billion in 2019, primarily on the NGTL System expansion projects, Canadian Mainline capacity projects and maintenance capital, all of which are immediately reflected in investment base. In addition, we spent $0.1 billion on advancing the Coastal GasLink project and we expect to spend an additional $1.0 billion in 2019, prior to any contributions from potential third party investors.

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 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 the capital invested to be too high.

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 it provides some certainty for shippers in terms of rates, eliminates the costs associated with a rate proceeding for all parties and can provide an incentive for pipelines to lower costs.

Additionally, we operate a non-regulated Midstream business that provides midstream services including gathering, treating, conditioning, processing, compression and liquids handling in the Appalachian Basin. The Midstream footprint consists of over 295 km (183 miles) of pipeline ranging in size from 16 to 36 inches. Midstream also manages our mineral rights positions in the Marcellus and Utica shale areas.

TC PipeLines, LP

We own a 25.5 per cent interest in, and are the general partner of, TC PipeLines, LP, an MLP which trades on the NYSE under the symbol TCP. TC PipeLines, LP has ownership interests in the GTN, Northern Border, Bison, Great Lakes, North Baja, Tuscarora, Iroquois, and Portland pipeline systems. Our overall effective ownership for each of these assets considering the ownership through the MLP is provided in the asset listing of our major pipelines starting on page 34.

SIGNIFICANT EVENTS

Mountaineer XPress and Gulf XPress

Mountaineer XPress (MXP), a Columbia Gas project, is designed to transport supply from the Marcellus and Utica shale plays to points along the system and to the Leach interconnect with Columbia Gulf. Approximately 45 per cent of this project was placed in service on January 18, 2019, with the remainder to be placed in service in February and March 2019, along with Gulf XPress, a Columbia Gulf project. Total estimated MXP project costs have been revised upwards to US$3.2 billion reflecting the impact of delays of various regulatory approvals from 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.

Louisiana Xpress

In November 2018, we sanctioned the Louisiana XPress project which will connect supply directly to Gulf Coast LNG export markets with the addition of three greenfield mid-point compressor stations along Columbia Gulf. The anticipated in-service date is in 2022 and estimated project costs are US$0.4 billion.

Cameron Access

The Cameron Access project, a Columbia Gulf project designed to transport approximately 0.9 PJ/d (0.8 Bcf/d) of gas supply to the Cameron LNG export terminal in Louisiana, was placed in service in March 2018.

WB XPress

The WB XPress project, a Columbia Gas project designed to transport approximately 1.4 PJ/d (1.3 Bcf/d) of Marcellus gas supply westbound to the Gulf Coast and eastbound to Mid-Atlantic Markets, was placed in service in October 2018 and November 2018 for the Western Build and Eastern Build, respectively.

Nixon Ridge

On June 7, 2018, a natural gas pipeline rupture on Columbia Gas occurred on Nixon Ridge in Marshall County, West Virginia. Emergency response procedures were enacted and the segment of impacted pipeline was isolated shortly thereafter. There were no injuries involved with this incident and no material damage to surrounding structures. The pipeline was placed back in service on July 15, 2018. The preliminary investigation, as noted in the PHMSA Proposed Safety Order, suggests that the rupture was a result of land subsidence. The investigation remains ongoing and we are fully cooperating with PHMSA to determine the root cause of the incident. This event did not have a significant impact on our 2018 financial results.

U.S. Natural Gas Pipelines rate settlements

Since September 30, 2018, a number of rate settlements have been reached with customers in response to the 2018 FERC Actions. As of the end of January 2019, rate settlements for certain of our FERC-regulated natural gas pipelines and gas storage assets have been approved or accepted by FERC. Refer to the 2018 FERC Actions section for further information.

Bison contract terminations and asset impairment

In the second half of 2018, two customers on Bison elected to pay out the remainder of their future contracted revenues and terminate their associated TSAs. The termination of these agreements was agreed to following the receipt of US$97 million in 2018, which was recorded in Revenues, as the terminations released us from providing any future services. This development, coupled with the persistence of unfavourable market conditions which have inhibited system flows on the pipeline, led us to determine that the asset's remaining carrying value was no longer recoverable and a non-cash impairment charge of US$537 million was recorded in our U.S. Natural Gas Pipelines segment. As Bison is a TC PipeLines, LP asset, in which we have a 25.5 per cent interest, this impairment charge impacts our net income by $140 million after tax and non-controlling interests, but is excluded from comparable earnings. We continue to explore alternative transportation-related options for Bison. Refer to the Critical accounting estimates section for further details.

Tuscarora goodwill impairment

In fourth quarter 2018, Tuscarora finalized its regulatory approach in response to the 2018 FERC Actions, resulting in a reduction in its recourse rates. In connection with its annual goodwill impairment analysis, we evaluated Tuscarora's future revenues as well as changes to other assumptions responsive to Tuscarora's commercial environment. In doing so, we incorporated the outcome of a settlement-in-principle reached with its customers in January 2019. As a result of these developments, we determined that the fair value of Tuscarora did not exceed its carrying value, including goodwill, and recorded a goodwill impairment charge of US$59 million within the U.S. Natural Gas Pipelines segment. The remaining goodwill balance related to Tuscarora at December 31, 2018 was US$23 million (2017 – US$82 million). As Tuscarora is a TC PipeLines, LP asset, in which we have a 25.5 per cent interest, this impairment charge impacts our net income by $15 million after tax and non-controlling interests, but is excluded from comparable earnings. Refer to the Critical accounting estimates section for further details.

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). See page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of US$, unless otherwise noted)	2018	2017	2016
Columbia Gas[1]	**873**	623	269
ANR	**508**	400	321
TC PipeLines, LP[2,3]	**138**	118	118
Midstream[1]	**122**	93	40
Columbia Gulf[1]	**120**	76	25
Great Lakes[3,4]	**97**	64	60
Other U.S. pipelines[2,3,5]	**68**	80	71
Non-controlling interests[6]	**415**	359	365
Comparable EBITDA	**2,341**	1,813	1,269
Depreciation and amortization	**(511)**	(453)	(322)
Comparable EBIT	**1,830**	1,360	947
Foreign exchange impact	**541**	410	310
Comparable EBIT (Cdn$)	**2,371**	1,770	1,257
Specific items:			
Bison asset impairment[7]	**(722)**	—	—
Tuscarora goodwill impairment[7]	**(79)**	—	—
Bison contract terminations[7]	**130**	—	—
Integration and acquisition related costs – Columbia	**—**	(10)	(63)
TC Offshore loss on sale	**—**	—	(4)
Segmented earnings (Cdn$)	**1,700**	1,760	1,190

1 We completed the acquisition of Columbia on July 1, 2016. Results reflect our effective ownership in these assets from that date.

2 Results reflect our earnings from TC PipeLines, LP's ownership interests in GTN, Great Lakes, Iroquois, Northern Border, Bison, Portland, North Baja and Tuscarora, as well as general and administrative costs related to TC PipeLines, LP. Results from Northern Border and Iroquois reflect our share of equity income from these investments. We acquired additional interests in Iroquois of 4.87 per cent on March 31, 2016 and 0.65 per cent on May 1, 2016. TC PipeLines, LP acquired 49.34 per cent of our 50 per cent interest in Iroquois on June 1, 2017. On January 1, 2016, we sold a 49.9 per cent direct interest in Portland to TC PipeLines, LP and the remaining 11.81 per cent to TC PipeLines, LP on June 1, 2017.

3 TC PipeLines, LP periodically conducted ATM issuances which decreased our ownership in TC PipeLines, LP. Effective March 2018, this program ceased to be utilized. Our ownership interest in TC PipeLines, LP was 25.5 per cent as at December 31, 2018 compared to 25.7 per cent and 26.8 per cent at December 31, 2017 and December 31, 2016, respectively.

4 Represents our 53.6 per cent direct interest in Great Lakes. The remaining 46.4 per cent is held by TC PipeLines, LP.

5 Results reflect earnings from our direct ownership interests in Crossroads, as well as Iroquois and Portland until June 1, 2017, our effective ownership in Millennium and Hardy Storage, and general and administrative and business development costs related to U.S. natural gas pipelines.

6 Results reflect earnings attributable to portions of TC PipeLines, LP, Portland (until June 1, 2017) and Columbia Pipeline Partners LP (CPPL) (until February 17, 2017) that we do not own.

7 These amounts were recorded in TC PipeLines, LP. The pre-tax impact to us is 25.5 per cent of these amounts net of non-controlling interests.

U.S. Natural Gas Pipelines segmented earnings in 2018 decreased by $60 million compared to 2017 and increased by $570 million in 2017 compared to 2016. Segmented earnings in 2018 include the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a $722 million non-cash asset impairment charge related to Bison
- a $79 million non-cash goodwill impairment charge related to Tuscarora
- $130 million of termination payments received on two of Bison's transportation contracts, which was recorded in Revenues.

Each of the specific items noted above are pre-tax and before reduction for the 74.5 per cent non-controlling interests in TC Pipelines, LP.

Segmented earnings in 2017 included pre-tax costs of $10 million mainly related to retention and severance expenses resulting from the Columbia acquisition. Segmented earnings in 2016 also included a pre-tax loss of $4 million as a result of a December 2015 agreement to sell TC Offshore, which closed in March 2016. These amounts have been excluded from our calculation of comparable EBIT and comparable earnings.

Earnings from our U.S. Natural Gas Pipelines operations, which include Columbia effective July 1, 2016, 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 storage capacity and incidental commodity sales. 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$528 million higher in 2018 than 2017 primarily due to the net effect of:

- increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes, and improved commodity prices and throughput volumes in Midstream
- increased earnings due to the amortization of the net regulatory liabilities that were recorded at the end of 2017, partially offset by a reduction in certain rates on Columbia Gas as a result of U.S. Tax Reform
- a US$10 million refund from GTN to its recourse rate customers as per the 2018 GTN Settlement. Refer to the 2018 FERC Actions section for additional details.

Comparable EBITDA for U.S. Natural Gas Pipelines was US$544 million higher in 2017 than 2016 primarily due to the net effect of:

- a full year contribution from the Columbia assets acquired in 2016
- higher ANR transportation revenue resulting from a FERC-approved rate settlement, effective August 1, 2016.

Depreciation and amortization

Depreciation and amortization was US$58 million higher in 2018 compared to 2017 mainly due to new projects placed in service and US$131 million higher in 2017 compared to 2016 primarily due to our acquisition of Columbia and increased depreciation rates on ANR following its rate settlement effective August 1, 2016.

OUTLOOK

Earnings

U.S. Natural Gas Pipelines earnings are affected by the level of contracted capacity and the rates charged to customers. Our ability to 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. Earnings are also affected by the level of operational and other costs, which can be impacted by safety, environmental and other regulators' decisions.

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.

U.S. Natural Gas Pipelines earnings are expected to be higher in 2019 than in 2018 due to, among other factors, increased revenues following the completion of expansion projects on the Columbia Gas and Columbia Gulf systems in 2018 and 2019. These projects will provide our customers with increased access to new sources of supply while extending their market reach. Further, we continue to pursue expansions across our existing geographical footprint that are expected to allow for the transport of additional natural gas production in the constrained Marcellus and Utica producing regions to areas of demand.

We continue to seek opportunities to expand on these developments, along with continued growth in end-use markets for natural gas, as we examine commercial, regulatory and operational changes to optimize our pipelines' positions in response to positive developments in supply fundamentals.

ANR is positioned to continue to benefit from its combination of long-term contracts originating in the Utica and Marcellus shale plays, a broad reach of storage and transmission services to customers in the Midwest, and its connectivity to Gulf Coast area production and end-use markets including LNG exporters. We expect ANR to provide stable earnings for 2019 consistent with 2018.

As a result of the 2018 FERC Actions, we do not anticipate that the earnings and cash flows from our directly-held U.S. natural gas pipelines, including ANR, Columbia Gas and Columbia Gulf, will be materially impacted as a significant proportion of their overall revenues are earned under non-recourse rates. As our ownership interest in TC PipeLines, LP is 25.5 per cent, the limited impact of the 2018 FERC Actions related to our investment in TC PipeLines, LP is not expected to be significant to our consolidated earnings or cash flows. For more information on the impact of the 2018 FERC Actions and filings in response to the Final Rule, refer to the 2018 FERC Actions section.

Capital spending

We spent a total of US$4.4 billion in 2018 on our U.S. natural gas pipelines and expect to spend approximately US$1.5 billion in 2019 primarily on completion costs for the Columbia Gas and Columbia Gulf expansion projects, ANR and Columbia Gas maintenance capital, which is generally expected to be recovered in future tolls, and our Columbia Gas Modernization program.

Mexico Natural Gas Pipelines

UNDERSTANDING OUR MEXICO NATURAL GAS PIPELINES SEGMENT

For over a decade, Mexico has been undergoing a significant transition from using fuel oil and diesel to using natural gas as its primary energy source for electric generation. As a result, new natural gas pipeline infrastructure is required to meet the growing demand for natural gas. Large natural gas pipelines in Mexico have been developed primarily through a competitive bid process whereby pipeline companies propose a cash flow stream over a 25-year contract based on their estimate of construction and ongoing operating costs. The revenues in these 25-year contracts are predominately denominated in U.S. dollars and are underpinned by the CFE, Mexico's state-owned electric utility. As pipeline operator, we are at risk for the construction and ongoing operating costs and subject to penalties, excluding force majeure events.

Our Mexico pipelines have approved tariffs, services and related rates for other potential users of the pipeline. All of the contracts that underpin the construction and operation of the pipelines in Mexico are long-term, fixed-rate contracts designed to recover the cost of our service and earn a return on and of invested capital.

SIGNIFICANT EVENTS

Topolobampo

In June 2018, the Topolobampo pipeline was placed in service. The 560 km (348 miles) pipeline provides capacity of 720 TJ/d (670 MMcf/d), receiving natural gas from upstream pipelines near El Encino, in the state of Chihuahua, and delivering to points along the pipeline route including our Mazatlán pipeline at El Oro, in the state of Sinaloa. Under the force majeure terms of the TSA, we began collecting and recognizing revenue from the original TSA service commencement date of July 2016.

Sur de Texas

Offshore construction was completed in May 2018 and the project continues to progress toward an anticipated in-service date in early second quarter 2019. An amending agreement was signed with the CFE that recognizes force majeure events and the commencement of payments of fixed capacity charges began on October 31, 2018.

Tula and Villa de Reyes

The CFE has approved the recognition of force majeure events for both of these pipelines, including the continuation of the payment of fixed capacity charges to us that began in first quarter 2018. Construction for the Villa de Reyes project is ongoing and is anticipated to be in service in the second half of 2019. Commencement of construction of the central segment of the Tula project has been delayed due to a lack of progress by the Secretary of Energy, the governmental department responsible for Indigenous consultations. Project completion has been revised to the end of 2020. We have negotiated separate CFE contracts that would allow certain segments of Tula and Villa de Reyes to be placed in service when gas is available.

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). See page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of US$, unless otherwise noted)	2018	2017	2016
Topolobampo	**172**	157	81
Tamazunchale	**127**	112	105
Mazatlán	**78**	65	5
Guadalajara	**71**	68	67
Sur de Texas[1]	**16**	8	—
Other	**4**	(11)	(8)
Comparable EBITDA	**468**	399	250
Depreciation and amortization	**(75)**	(72)	(35)
Comparable EBIT	**393**	327	215
Foreign exchange impact	**117**	99	72
Comparable EBIT and segmented earnings (Cdn$)	**510**	426	287

1 Represents our 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline.

Mexico Natural Gas Pipelines segmented earnings in 2018 increased by $84 million compared to 2017 and increased by $139 million in 2017 compared to 2016.

Comparable EBITDA for Mexico Natural Gas Pipelines was US$69 million higher in 2018 than 2017 mainly due to the net effect of:

- higher revenues from operations as a result of changes in timing of revenue recognition
- incremental earnings from a CRE tariff increase
- the $12 million impairment of our equity investment in TransGas in 2017, recorded in Other above
- equity earnings from our investment in the Sur de Texas pipeline which records AFUDC during construction, net of interest expense on an inter-affiliate loan from TransCanada. The interest expense on this inter-affiliate loan is fully offset in Interest income and other in the Corporate segment.

Comparable EBITDA for Mexico Natural Gas Pipelines was US$149 million higher in 2017 than 2016 mainly due to the net effect of:

- incremental earnings from Topolobampo beginning July 2016 and Mazatlán beginning December 2016
- equity earnings from our investment in the Sur de Texas pipeline which records AFUDC during construction, net of interest expense on an inter-affiliate loan from TransCanada which is fully offset in Interest income and other in the Corporate segment.

Depreciation and amortization

Depreciation and amortization in 2018 remained consistent with 2017. Depreciation and amortization increased by US$37 million in 2017 compared to 2016 primarily due to the commencement of depreciation on Topolobampo and Mazatlán.

OUTLOOK

Earnings

Mexico Natural Gas Pipelines earnings reflect long-term, stable, principally U.S. dollar-denominated revenue contracts that are affected by the cost of providing service and include our share of equity income from our 60 per cent effective interest in the Sur de Texas pipeline.

Due to the long-term nature of the underlying revenue contracts, earnings are generally consistent year-over-year. Earnings for 2019 are expected to be higher than in 2018 primarily due to the incremental contribution from the Sur de Texas pipeline, which is expected to be in service in early second quarter 2019.

Capital spending

We spent a total of US$0.6 billion in 2018 on our Mexico natural gas pipelines and expect to spend approximately US$0.3 billion in 2019, primarily on completion of the Sur de Texas and Villa de Reyes pipelines.

NATURAL GAS PIPELINES – BUSINESS RISKS

The following are risks specific to our natural gas pipelines business. See page 85 for information about general risks that affect the company as a whole, including other operational and financial risks.

Production levels within supply basins

Our pipelines downstream of the NGTL System depend largely on supply from the WCSB. Our Columbia System and its connecting pipes 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 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, basin-on-basin competition, downstream pipeline tolls, demand within the basin 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 being developed closer to markets we have historically served may reduce the throughput and/or distance of haul on our existing pipelines and impact revenue. New markets created by LNG export facilities developed to access global natural gas demand can lead to increased revenue 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 alternative transportation services at prices that are acceptable to the market.

Competition for greenfield expansion

We face competition from other pipeline companies seeking to invest in greenfield natural gas pipeline development opportunities. This competition could result in fewer projects being available that meet our investment hurdles or projects that proceed with lower overall financial returns.

Demand for pipeline capacity

Demand for pipeline capacity is ultimately the key driver that enables pipeline transportation services to be sold and is impacted by supply and market competition, variations in economic activity, weather variability, natural gas pipeline and storage competition and pricing of alternative fuels. Renewal of expiring contracts and the opportunity to charge and collect a toll that the market accepts depends on the overall demand for transportation service. A decrease in the level of demand for our pipeline transportation services could adversely impact revenues.

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 for the demand of transportation services and/or new natural gas pipeline infrastructure. As well, sustained low natural gas prices could impact our shippers' financial condition and their ability to meet their transportation service cost obligations.

Regulatory risk

Decisions by regulators and other government authorities, including changes in regulation, can have an impact on 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 therefore could adversely impact construction costs, in-service dates, anticipated revenues, and the opportunity to further invest capital 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 slowed or lead to an unfavourable decision due to influence from the evolving role of activists and their impact on public opinion and government policy related to natural gas pipeline infrastructure development.

Increased scrutiny of operating processes by the regulator or other enforcing agencies has the potential to 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.

We continuously monitor regulatory developments and decisions to determine the possible impact on our natural gas pipelines business. We also work closely with our stakeholders in the development of rate, facility and tariff applications and negotiated settlements, where possible.

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 our throughput capacity may result in reduced revenue 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 24 hours a day every day, 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 whenever necessary. We also calibrate meters regularly to ensure accuracy, and continuously maintain compression equipment to ensure safe and reliable operation.

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.

Strategy at a glance

- focus on accessing and delivering growing North American liquids supply to key markets by expanding our crude oil pipelines infrastructure to deliver directly from supply regions seamlessly along a contiguous path to market
- maximizing the value from our current operating assets and securing organic growth around these assets
- positioning our business development activities to identify and capture attractive organic growth and acquisition opportunities
- expand transportation service offerings to other areas of the liquids value chain including ancillary services such as short- and long-term storage of liquids, which complement our pipeline transportation infrastructure.

Highlights

- commenced construction on the White Spruce pipeline
- obtained shipper commitments on all available Keystone XL project capacity
- completed construction of an additional one million barrels of crude oil storage at our Cushing Terminal in Oklahoma.


TransCanada
Liquids Pipelines
As at December 31, 2018
Liquids Pipeline
In Development/Construction
Liquids Tank Terminal
Production Basin
Western Canadian Sedimentary Basin
Oil Sands
Duvernay
CANADA
CALGARY
Williston
TORONTO
Denver-Julesburg
UNITED STATES
Anadarko
CHARLESTON
Permian
HOUSTON
Eagle Ford
MEXICO
MEXICO CITY
1
2
3
4
5
6
7
8
9
10
11

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	Northern Courier	90 km (56 miles)	Transports bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta.	100%
	Under construction			
5	White Spruce	72 km (45 miles)	To transport crude oil from the Canadian Natural Resources Limited's Horizon facility in northeast Alberta into the Grand Rapids pipeline.	100%
	In development			
6	Keystone XL	1,947 km (1,210 miles)	To transport crude oil from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System.	100%
7	Keystone Hardisty Terminal		Crude oil terminal located at Hardisty, Alberta.	100%
8	Bakken Marketlink		To transport crude oil from the Williston Basin producing region in North Dakota and Montana to Cushing, Oklahoma and the U.S. Gulf Coast on facilities that form part of the Keystone Pipeline System.	100%
9 10	Heartland and TC Terminals	200 km (125 miles)	Terminal and pipeline facilities to transport crude oil from the Edmonton/Heartland, Alberta region to Hardisty, Alberta.	100%
11	Grand Rapids Phase II	460 km (286 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 business consists of crude oil and products pipelines. We efficiently transport crude oil from major supply sources to markets where crude oil can be refined into various petroleum products, transport diluent and diesel products within northern Alberta, and offer ancillary services such as short- and long-term storage of liquids at key terminal locations to optimize the value of our pipeline assets.

We provide pipeline transportation capacity to shippers 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 shippers which provide for the recovery of costs we incur to construct, operate and maintain the system. Uncontracted pipeline capacity is offered to the market to secure additional contracts 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 western Canadian crude oil exports to key refining markets in the U.S. Midwest and the U.S. Gulf Coast, and provides significant capacity between Cushing, Oklahoma and the U.S. Gulf Coast market to primarily transport U.S. crude oil. The Grand Rapids and Northern Courier pipelines, two intra-Alberta liquids pipelines, provide crude oil, diluent and diesel 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, primarily through the purchase and sale of physical crude oil. TransCanada Liquids Marketing holds contractual rights on TransCanada pipelines and will seek to contract capacity as required on third-party owned pipelines and tank terminals.

Business environment

Global crude oil demand continues to grow despite a shift towards fuel efficiency and cleaner energy technologies, driven mainly by increasing demand in Asia and global population growth which is expected to increase by more than 11 per cent by 2030. Global crude oil demand growth is projected to increase from 82 million Bbl/d in 2017 to 91 million Bbl/d in 2030, driven primarily by the transportation and industrial sectors. In addition to meeting this anticipated crude oil demand growth of approximately 9.0 million Bbl/d, a significant amount of crude oil production capacity is required to meet global annual conventional decline rates of approximately 27 million Bbl/d of crude oil by 2030.

To meet this combined 36 million Bbl/d demand requirement to 2030, a strong crude oil price environment will be needed to support continuing investment. Global supply of crude oil necessary to meet this demand is largely supported by countries with significant crude oil reserves, mainly in North America and the Middle East. Crude oil prices have strengthened since experiencing a global oversupply in 2014, as crude oil supply management efforts, primarily by OPEC, and global demand growth have combined to stabilize and provide sufficient support for ongoing infrastructure investments.

Supply and demand outlook

Canada

Canada has the world's third largest crude oil reserves with approximately 164 billion barrels of economically and technically recoverable conventional and oil sands reserves in Alberta as of 2017. Total 2018 WCSB crude oil production was approximately 4.5 million Bbl/d and is expected to increase to 5.7 million Bbl/d by 2030, 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 3.3 million Bbl/d and is a favourable supply source given its long reserve life and steady production.

Canada's proximity to the U.S., which is the world's largest consumer of crude oil at 18 million Bbl/d,and Canada's significant heavy crude oil production is of strategic importance to the U.S. refining industry. The U.S. Midwest and U.S. Gulf Coast refining marketshave a strong reliance on heavy crude oil imports of approximately 5.0 million Bbl/d. Canada is currently the largest exporter of crude oil to the U.S. at approximately 3.4 million Bbl/d. Demand for heavy crude oil in the U.S. has been resilient and is expected to remain as such 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.

The U.S. Midwest refiners have total refining capacity of approximately 3.8 million Bbl/d, which requires approximately 1.8 million Bbl/d of heavy crude oil. The U.S. Gulf Coast is the largest regional refining center in the world with a total capacity of 9.7 million Bbl/d, which is more than half of the total U.S. refining capacity. The U.S. Gulf Coast imported 3.1 million Bbl/d of crude oil in 2018 to meet demand, of which 2.1 million Bbl/d was heavy crude oil. Many refiners in the U.S. Midwest and U.S. Gulf Coast process a wide variety of crudes, including significant amounts of heavy crude oil. This flexibility, access to an abundance of low-cost natural gas, proximity of light and heavy crude oil supply and ready access to markets, has positioned these refineries to be the most profitable in the world.

U.S.

The U.S. has become one of the world's largest crude oil producers, exceeding 11 million Bbl/d in the fourth quarter of 2018, which is attributable to significant light tight oil production growth. The majority of continental U.S. crude oil production is from the Williston, Eagle Ford, Niobrara and Permian basins. The Permian basin is the dominant region accounting for approximately 40 per cent of total U.S. crude oil production and is expected to grow by 3.0 million Bbl/d by 2030.

Due to the current light oil processing capacity being fully utilized in the U.S., the U.S. exports the majority of light tight oil, which is currently over 2.0 million Bbl/d. By 2030, the U.S. is expected to export approximately 3.0 million Bbl/d of crude oil.

Strategic priorities

Our strategic focus is to provide transportation solutions which link growing supply basins in North America to key market hubs and demand centers. Our intra-Alberta and Keystone pipeline systems will form a contiguous path from Alberta through the U.S. Midwest to the U.S. Gulf Coast, which strategically positions TransCanada to provide competitive transportation solutions for growing supplies of Alberta heavy crude oil and U.S. light tight oil.

We remain committed to:

- expanding and leveraging our existing infrastructure
- protecting and optimizing the value of our existing assets
- expanding the transportation services that we offer and extend into adjacent jurisdictions
- extending into emerging growth opportunities.

We continue to work with existing and new customers to provide pipeline transportation and terminal services. The combination of the scale and location of our assets assists us in attracting new volumes and growing our business.

In 2019 one of our key focus areas will be to progress Keystone XL into construction, more than doubling the capacity of the Keystone Pipeline System with enhanced access to over 4.3 million Bbl/d of refinery capacity in Houston and Port Arthur, Texas. Expanding the pipeline capacity to these key markets is expected to enhance both short and long-haul volumes.

Within Alberta, we continue to develop and grow our intra-Alberta liquids pipelines business. The White Spruce pipeline, once completed, will transport crude oil from Canadian Natural Resources Limited's Horizon facility into Grand Rapids and will further expand our regional footprint. With additional commercial support, the Heartland pipeline, Heartland Terminal and Hardisty Terminal projects, all of which have received regulatory approval, will allow shippers to seamlessly connect from the Fort McMurray production region directly to market.

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. We will also focus on leveraging our existing assets and development of projects to reach emerging growth regions such as the Williston, Niobrara and Permian 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 have agreed to provide pipeline capacity to our customers in exchange for fixed monthly payments which are not affected by commodity prices or throughput. The cyclical nature of commodity prices may influence the pace at which our shippers 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.

We closely monitor the market place for strategic asset acquisitions 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.

SIGNIFICANT EVENTS

Keystone Pipeline System

In 2018, we concluded successful open seasons for Marketlink securing incremental contractual support.

We continue to expand our terminal facilities which are integral to our operations, with the completion of an additional one million barrels of storage at Cushing, Oklahoma in 2018.

Keystone XL

We have secured commercial support for all available Keystone XL project capacity and commenced certain pre-construction activities.

In November 2017, the Nebraska PSC approved a route for the Keystone XL project through the state. The Nebraska Supreme Court agreed to hear an appeal of the Nebraska PSC route approval, in which oral arguments were heard in November 2018. We expect the Nebraska Supreme Court, as the final arbiter, could reach a decision in first quarter 2019.

The Keystone XL Presidential Permit (Presidential Permit), issued in 2017, was challenged in two separate lawsuits commenced in Montana. Together with the DOJ, we are actively participating in these lawsuits to defend both the issuance of the permit and the exhaustive environmental assessments that support the U.S. President's actions. Legal arguments addressing the merits of these lawsuits were heard in second quarter 2018.

In third quarter 2018, the U.S. District Court in Montana issued a Partial Order requiring the DOJ and the DOS (collectively, the Federal Defendants) to prepare a supplemental environmental impact statement (SEIS) to the 2014 Final SEIS.

In fourth quarter 2018, the U.S. District Court Judge in Montana invalidated the Presidential Permit and granted a partial injunction on the Keystone XL project. We applied to the U.S. District Court for a stay of its various decisions affecting the issuance of the Presidential Permit and the extensive environmental assessments that have been done in support of its issuance. That stay application was heard on January 14, 2019 and we are awaiting a decision. We intend to further pursue a stay of these decisions with the Ninth Circuit Court of Appeals. Our plans to commence construction of the Keystone XL project in 2019 will be impacted by the timing and outcome of our appeal and stay proceedings.

In September 2018, two U.S. Native American communities filed a lawsuit in Montana challenging the Presidential Permit. We have been granted intervenor status in the lawsuits. Initial briefing dates have been established, but no further action has occurred.

The South Dakota Public Utilities Commission permit for the Keystone XL project was issued in June 2010 and certified in January 2016. An appeal of that certification was denied in June 2017 and that decision was further appealed to the South Dakota Supreme Court. In June 2018, the Supreme Court dismissed the appeal against the certification of the Keystone XL project finding that the lower court lacked jurisdiction to hear the case. This decision is final as there can be no further appeals from this decision by the Supreme Court.

White Spruce

In February 2018, the AER issued a permit for the construction of the $200 million White Spruce pipeline, which will transport crude oil from Canadian Natural Resources Limited's Horizon facility in northeast Alberta to the Grand Rapids pipeline. Construction has commenced with an anticipated in-service date in second quarter 2019.

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). See page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2018	2017	2016
Keystone Pipeline System	**1,443**	1,283	1,155
Intra-Alberta pipelines	**160**	33	—
Liquids marketing and other	**246**	32	(3)
Comparable EBITDA	**1,849**	1,348	1,152
Depreciation and amortization	**(341)**	(309)	(292)
Comparable EBIT	**1,508**	1,039	860
Specific items:			
Energy East impairment charge	**—**	(1,256)	—
Keystone XL asset costs	**—**	(34)	(52)
Risk management activities	**71**	—	(2)
Segmented earnings/(losses)	**1,579**	(251)	806
Comparable EBIT denominated as follows:			
Canadian dollars	**370**	255	223
U.S. dollars	**876**	604	482
Foreign exchange impact	**262**	180	155
Comparable EBIT	**1,508**	1,039	860

Liquids Pipelines segmented earnings increased by $1,830 million in 2018 compared to 2017 and decreased by $1,057 million in 2017 compared to 2016. Segmented losses in 2017 include the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a $1,256 million pre-tax impairment charge for the Energy East pipeline and related projects
- $34 million (2016 – $52 million) of pre-tax costs related to Keystone XL for the maintenance and liquidation of project assets which were expensed pending further advancement of the project.

Segmented earnings/(losses) includes unrealized gains and losses from changes in the fair value of derivatives related to our liquids marketing business. These amounts have been excluded from our calculation of comparable EBIT. The remainder of the Liquids Pipelines segmented earnings, with the exception of the specific items described above, are equivalent to comparable EBIT.

Comparable EBITDA for Liquids Pipelines was $501 million higher in 2018 compared to 2017 primarily due to the effect of:

- higher contracted and uncontracted volumes on the Keystone Pipeline System
- higher contribution from liquids marketing activities from improved margins and volumes
- incremental contributions from intra-Alberta pipelines, Grand Rapids and Northern Courier, which began operations in the second half of 2017
- lower business development costs as a result of capitalizing Keystone XL expenditures in 2018.

Comparable EBITDA for Liquids Pipelines was $196 million higher in 2017 compared to 2016 primarily due to the net effect of:

- higher uncontracted volumes on the Keystone Pipeline System
- a higher contribution from liquids marketing activities from improved margins and volumes
- contributions from intra-Alberta pipelines, Grand Rapids and Northern Courier, which began operations in the second half of 2017
- higher business development activities, including advancement of Keystone XL for which costs were expensed
- a weaker U.S. dollar which had a negative impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

Depreciation and amortization

Depreciation and amortization was $32 million higher in 2018 than in 2017 primarily as a result of new facilities being placed in-service. Depreciation and amortization was $17 million higher in 2017 than in 2016 as a result of new facilities being placed in-service, partially offset by the effect of a weaker U.S. dollar.

OUTLOOK

Earnings

Our 2019 earnings are expected to be similar to 2018, primarily as a result of significant take-or-pay contracts and continued high demand for capacity on our assets. Our liquids marketing business will hold capacity on TransCanada assets in 2019 at levels similar to 2018 and is expected to generate a similar amount of earnings in 2019.

Capital spending

We spent a total of $0.6 billion in2018 on our liquids pipelines and expect to spend approximately $0.6 billion in2019, primarily on advancing Keystone XL and constructing the White Spruce pipeline. A portion of the 2019 expenditures for advancing Keystone XL is recoverable from shippers under certain circumstances.

BUSINESS RISKS

The following are risks specific to our liquids pipelines business. See page 85 for information about general risks that affect TransCanada as a whole, including other operational and financial risks.

Construction and operations

Constructing and 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 impact our throughput capacity and may result in reduced fixed payment revenue and spot volume opportunities. We manage this by investing in a highly skilled workforce, 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.

While the majority of the costs to operate the liquids pipelines are passed through to our shippers, a portion of our volume is transported under an all-in fixed toll structure where we are exposed to changing costs which may adversely impact our earnings.

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. 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 some individuals and interest groups that are expressing their opposition to crude oil production by lobbying against the construction of liquids pipelines. Changing environmental requirements or revisions to the current regulatory process may adversely impact the timing or ability to obtain permit 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 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. 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 would negatively impact opportunities to expand our liquids pipelines infrastructure and, in the longer term, to re-contract with shippers 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 and diluent 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. 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.

Energy

Our Energy business consists of power generation and unregulated natural gas storage assets.

The power business includes approximately 6,600 MW of generation capacity that we currently either own or are developing. Our power generation assets are located in Alberta, Ontario, Québec, New Brunswick and Arizona, and are powered by natural gas and nuclear fuel sources. The majority of these assets are supported by long-term contracts.

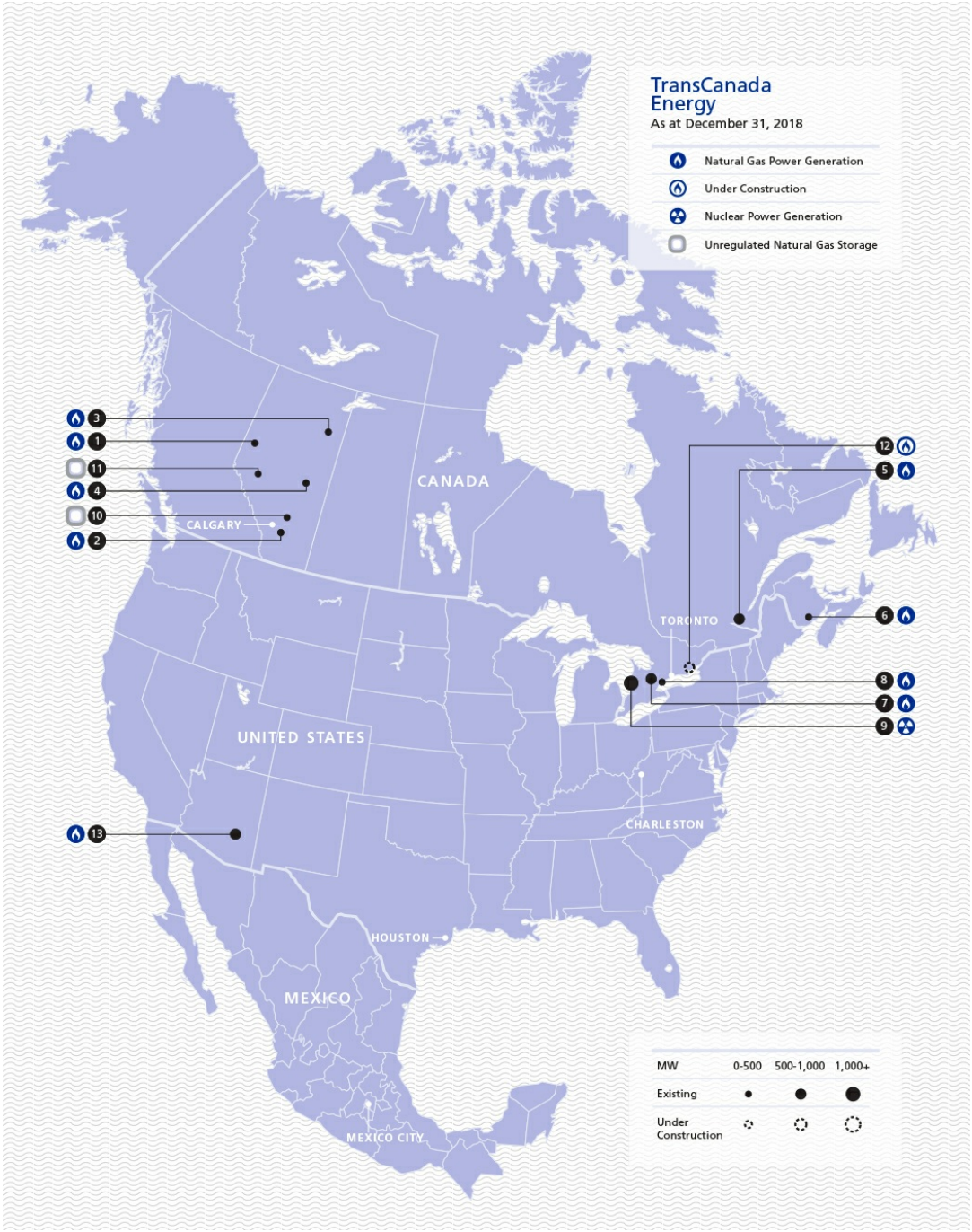
We own and operate approximately 118 Bcf of unregulated natural gas storage capacity in Alberta and hold a contract with a third party for additional storage, in total accounting for approximately one-third of all storage capacity in the province.

Strategy at a glance

- maximize the value of our portfolio of Energy assets through safe and optimized operations
- disciplined execution of capital programs
- pursue growth in contracted power infrastructure with a focus on our core markets of Alberta and Ontario.

Highlights

- advanced the life extension program at Bruce Power with the final Unit 6Major Component Replacement (MCR) cost and schedule duration estimate verified by the IESO. The Unit 6 MCR outage is scheduled to begin in early 2020
- completed the sale of our interests in the Cartier Wind power facilities
- entered into an agreement to sell our Coolidge power generation station for approximately US$465 million
- completed monetization of the U.S. Northeast power retail contracts as part of the continued wind-down of our U.S. Northeast power marketing business
- construction is substantially complete on the Napanee natural gas-fired power plant with expected in-service in second quarter 2019.


TransCanada Energy
As at December 31, 2018
Natural Gas Power Generation
Under Construction
Nuclear Power Generation
Unregulated Natural Gas Storage
CANADA
UNITED STATES
MEXICO
CALGARY
TORONTO
CHARLESTON
HOUSTON
MEXICO CITY
MW
0-500
500-1,000
1,000+
Existing
Under Construction

We are the operator of all our Energy assets, except for Bruce Power and Portlands Energy.

		Generating capacity (MW)	Type of fuel	Description	Ownership
	Power 6,615 MW of power generation capacity (including facilities under construction and held for sale)				
	Western Power 1,023 MW of power generation capacity in Alberta and Arizona (including asset held for sale)				
1	Bear Creek	100	natural gas	Cogeneration plant in Grande Prairie, Alberta.	100%
2	Carseland	95	natural gas	Cogeneration plant in Carseland, Alberta.	100%
3	Mackay River	207	natural gas	Cogeneration plant in Fort McMurray, Alberta.	100%
4	Redwater	46	natural gas	Cogeneration plant in Redwater, Alberta.	100%
	Eastern Power 2,498 MW of power generation capacity (including facility under construction)				
5	Bécancour	550	natural gas	Cogeneration plant in Trois-Rivières, Québec. Power sold under a 20-year PPA with Hydro-Québec which expires in 2026. Steam sold to an industrial customer. Power generation has been suspended since 2008. We continue to receive capacity payments while generation is suspended.	100%
6	Grandview	90	natural gas	Cogeneration plant in Saint John, New Brunswick. Power sold under a 20-year tolling agreement for 100 per cent of heat and electricity output with Irving Oil which expires in 2024.	100%
7	Halton Hills	683	natural gas	Combined-cycle plant in Halton Hills, Ontario. Power sold under a 20-year Clean Energy Supply contract with the IESO which expires in 2030.	100%
8	Portlands Energy	275[1]	natural gas	Combined-cycle plant in Toronto, Ontario. Power sold under a 20-year Clean Energy Supply contract with the IESO which expires in 2029.	50%
	Bruce Power 3,094 MW of power generation capacity				
9	Bruce Power	3,094[1]	nuclear	Eight operating reactors in Tiverton, Ontario. Bruce Power leases the eight nuclear facilities from OPG.	48.3%
	Unregulated natural gas storage 118 Bcf of non-regulated natural gas storage capacity				
10	Crossfield	68 Bcf		Underground facility connected to the NGTL System near Crossfield, Alberta.	100%
11	Edson	50 Bcf		Underground facility connected to the NGTL System near Edson, Alberta.	100%
	Under construction				
12	Napanee	900	natural gas	Combined-cycle plant in Greater Napanee, Ontario. Power sold under a 20-year Clean Energy Supply contract with the IESO which expires 20 years from in-service date. Expected in-service date is second quarter 2019.	100%
	Asset held for sale				
13	Coolidge	575	natural gas	Simple-cycle peaking facility in Coolidge, Arizona. Power sold under a 20-year PPA with the Salt River Project Agricultural Improvements & Power District which expires in 2031.	100%

1 Our share of power generation capacity.

UNDERSTANDING OUR ENERGY BUSINESS

Our Energy business is made up of two groups:

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

Power

Western Power

We own approximately 1,000 MW of power supply through four natural gas-fired cogeneration facilities in Alberta and the Coolidge natural gas peaking facility in Arizona. Although we have reached an agreement to sell our Coolidge power generating station, results from Coolidge will continue to be included in comparable EBITDA until the sale is complete.

A disciplined operating strategy is integral to maximizing revenue at our cogeneration facilities in Western Canada. Optimized plant operations are also critical to maximizing earnings at Coolidge, where revenue is based on plant availability and performance.

Our marketing group sells uncommitted power from the Alberta cogeneration plants, and buys and sells power and natural gas to maximize earnings from these assets. To reduce exposure associated with uncontracted power, we sell a portion of our power in forward sales markets when acceptable contract terms are available. A portion of our power is retained to be sold in the spot market or under short-term forward arrangements. This ensures we have adequate power supply to fulfill our sales obligations if we have unexpected plant outages and provides the opportunity to increase earnings in periods of high spot prices.

The Government of Alberta has implemented a process to procure additional renewable energy in the coming years along with adding a capacity market in 2021 to the current energy-only market design of the Alberta power market. We continue to monitor and participate in the industry and Government discussions on the Alberta power market to identify the impacts to our existing cogeneration facilities and opportunities for potential growth.

Eastern Power

We own or are constructing approximately 2,500 MW of power generation capacity in Eastern Canada, excluding Bruce Power. All the power produced by our Eastern Power assets is sold under long-term contracts.

Disciplined maintenance and optimized plant operations are essential to the results of our Eastern Power assets, where our earnings are based on plant availability and performance.

The IESO is in the process of reforming the wholesale energy market in Ontario to improve efficiency and introduce an incremental capacity market with an initial commitment year of 2024. The incremental capacity market is expected to incent existing power generating resources approaching contract expiry to remain in the market as well as procure incremental power generation supplies to meet adequacy requirements. We continue to monitor and participate in the industry engagement processes on the Ontario market reforms to identify impacts to our existing Ontario assets and opportunities for potential growth.

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 6,400 MW. Bruce Power leases the facilities from OPG and will return the facilities to OPG for decommissioning at the end of the lease. We hold a 48.3 per cent ownership interest in Bruce Power.

Results from Bruce Power fluctuate primarily due to 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 (AM) program is designed to result in near-term life extensions up to the planned major refurbishment outages and beyond. The MCR program includes work undertaken to replace key, life-limiting reactor components. The AM program includes the one-time refurbishment or replacement of systems, structures or components that are not within the scope of the MCR program.

The Unit 6 MCR program has been verified by the IESO and the outage is scheduled to proceed in early 2020 with expected completion in late 2023. Investments in the remaining five-unit MCR program 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.

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 AM and MCR capital 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. For the 2016 to 2018 period, the total to be paid to the IESO is approximately $200 million. Our 48.3 per cent share would be approximately $100 million.

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 storage businesses. We also hold a contract for additional Alberta-based storage capacity with a third party.

Our natural gas storage business helps balance seasonal and short-term supply and demand, and adds 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 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.

SIGNIFICANT EVENTS

Power

Cartier Wind

In October 2018, we completed the sale of our interests in the Cartier Wind power facilities in Québec to Innergex Renewable Energy Inc. for gross proceeds of approximately $630 million before closing adjustments, resulting in a gain of $170 million ($143 million after tax).

Coolidge Generating Station

On December 14, 2018, we entered into an agreement to sell our Coolidge generating station in Arizona to SWG Coolidge Holdings, LLC, for approximately US$465 million, subject to timing of the close and related adjustments. Salt River Project Agriculture Improvement and Power District, the PPA counterparty, exercised its contractual right of first refusal on a sale to a third party in January 2019. The sale will result in an estimated gain of approximately $65 million ($50 million after tax) to be recognized upon closing of the sale transaction, which is expected to occur mid-2019.

Bruce Power – Life Extension

In September 2018, Bruce Power submitted its final cost and schedule duration estimate (basis of estimate) for the Unit 6 MCR program to the IESO. The IESO has verified the basis of estimate and the Unit 6 MCR program is scheduled to begin in early 2020 with an expected completion in late 2023.

Our project cost estimates in our Capital Program tables reflect our expected investment of approximately $2.2 billion (in nominal dollars) in Bruce Power's Unit 6 MCR program and its ongoing AM program through 2023 as well as approximately $6.0 billion (in 2018 dollars) for the remaining five-unit MCR program and the remainder of the AM program beyond 2023. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available for Bruce Power and the IESO.

Bruce Power's current contract price of approximately $68 per MWh is expected to increase to approximately $75 per MWh on April 1, 2019 to reflect capital to be invested under the Unit 6 MCR program and the AM program as well as normal annual inflation adjustments.

Ontario Greenhouse Gas Regulations

The Government of Ontario canceled the provincial cap-and-trade program effective July 3, 2018. The regulation originally came into effect July 1, 2016 setting a limit on annual province-wide greenhouse gas emissions beginning January 1, 2017 and introduced a market to administer the purchase and trading of emission allowances. The cancellation of this regulation did not have a significant impact to our Energy business.

In June 2018, the Government of Canada passed into law the Greenhouse Gas Pollution Pricing Act which exposes natural gas-fired generators in Ontario to certain emission charges subject to the quantity of annual emissions produced. For facilities with annual emissions greater than 50,000 tonnes of CO_2 equivalent, an OBPS will be in effect as of January 1, 2019. Our natural gas power facilities in Ontario are subject to this OBPS program. At this time, we do not anticipate any material impact to the financial performance of our Ontario natural gas power facilities as a result of this program.

Napanee

Construction is substantially complete and commissioning activities are continuing at our 900 MW natural gas-fired power plant at OPG's Lennox site in eastern Ontario in the town of Greater Napanee. We expect our total investment in the Napanee facility will be approximately $1.7 billion with commercial operations expected to begin in second quarter 2019.

Monetization of U.S. Northeast power marketing business

In March 2018, as part of the continued wind-down of our U.S. Northeast power marketing contracts, we closed the sale of our U.S. power retail contracts for proceeds of approximately US$23 million and recognized income of US$10 million (US$7 million after tax).

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

year ended December 31 (millions of Canadian $, unless otherwise noted)	2018	2017	2016
Western and Eastern Power[1,2]	**428**	444	423
Bruce Power[2]	**311**	434	293
U.S. Power (US$)[3]	**—**	100	394
Foreign exchange impact on U.S. Power	**—**	30	128
Natural Gas Storage and other	**27**	55	58
Business Development[4]	**(14)**	(33)	(15)
Comparable EBITDA	**752**	1,030	1,281
Depreciation and amortization	**(119)**	(151)	(302)
Comparable EBIT	**633**	879	979
Specific items:			
Gain on sale of Cartier Wind power facilities	**170**	—	—
U.S. Northeast power marketing contracts	**(5)**	—	—
Net gain/(loss) on sales of U.S. Northeast power generation assets	**—**	484	(844)
Gain on sale of Ontario solar assets	**—**	127	—
Ravenswood goodwill impairment	**—**	—	(1,085)
Alberta PPA terminations and settlement	**—**	—	(332)
Risk management activities	**(19)**	62	125
Segmented earnings/(losses)	**779**	1,552	(1,157)

1 Includes losses from the Alberta PPAs up to March 2016 when the PPAs were terminated.
2 Includes our share of equity income from our investments in Portlands Energy and Bruce Power.
3 In second quarter 2017, we completed the sales of our U.S. Northeast power generation assets.
4 Includes a $21 million impairment charge in 2017 related to obsolete equipment.

Energy segmented earnings decreased $773 million in 2018 compared to 2017 and increased $2,709 million in 2017 compared to 2016 and included the following specific items:

- a pre-tax gain in 2018 of $170 million related to the sale of our interests in the Cartier Wind power facilities. Refer to the Significant events section for more details
- a pre-tax net loss of $5 million in 2018 related to our U.S. Northeast power marketing contracts, including a gain in first quarter 2018 on the sale of our retail contracts. These results have been excluded from Energy's comparable earnings in 2018 as we do not consider the wind-down of the remaining contracts part of our underlying operations. The contract portfolio is scheduled to run-off through to mid-2020. Refer to the Significant events section for more details on the sale of our retail contracts
- a pre-tax net gain in 2017 of $484 million (2016 – loss of $844 million) related to the monetization of our U.S. Northeast power generation assets which included a $715 million gain on the sale of TC Hydro, a loss of $211 million (2016 – $829 million) on the sale of the thermal and wind package and $20 million (2016 – $15 million) of pre-tax disposition costs
- a pre-tax gain in 2017 of $127 million related to the sale of our Ontario solar assets
- a $1,085 million pre-tax impairment of Ravenswood goodwill in 2016. As a result of information received during the process to monetize our U.S. Northeast power business in third quarter 2016, it was determined that the fair value of Ravenswood no longer exceeded its carrying value
- a $332 million pre-tax charge in 2016 which included a $211 million impairment charge on the carrying value of our Alberta PPAs, a $29 million impairment of our equity investment in ASTC Power Partnership, and a $92 million loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the PPA terminations
- unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain commodity price risks, as noted in the table below:

Risk management activities (millions of $, pre-tax)	**2018**	**2017**	**2016**
Canadian Power	**3**	11	4
U.S. Power	**(11)**	39	113
Natural Gas Storage	**(11)**	12	8
Total unrealized (losses)/gains from risk management activities	**(19)**	62	125

Comparable EBITDA for Energy decreased $278 million in 2018 compared to 2017 primarily due to the net effect of:

- lower earnings from U.S. Power mainly due to the sales of the U.S. Northeast power generation assets in second quarter 2017
- decreased earnings from Bruce Power primarily due to lower volumes resulting from higher outage days and lower results from contracting activities. Additional financial and operating information on Bruce Power is provided below
- decreased Natural Gas Storage results due to pipeline constraints in the Alberta natural gas market which limited our ability to access our storage facilities and resulted in lower realized natural gas storage price spreads
- lower earnings from Western and Eastern Power due to the sales of our Ontario solar assets in December 2017 and our interest in the Cartier Wind power facilities in October 2018, partially offset by higher Western Power realized margins on higher generation volumes.

Comparable EBITDA for Energy decreased $251 million in 2017 compared to 2016 primarily due to the net effect of:

- lower earnings from U.S. Power mainly due to the sales of the U.S. Northeast power generation assets in second quarter 2017 and the wind-down of our U.S. power marketing contracts
- increased earnings from Bruce Power mainly due to higher volumes resulting from fewer outage days
- higher earnings from Western and Eastern Power primarily due to the termination of the Alberta PPAs.

Depreciation and amortization

Depreciation and amortization decreased by $32 million in 2018 compared to 2017 primarily due to the sale of our Ontario Solar assets in December 2017 as well as the cessation of depreciation on our Cartier Wind power facilities upon classification as held for sale at June 30, 2018. Depreciation was $151 million lower in 2017 compared to 2016 as depreciation on our U.S. Northeast power generation assets ceased effective November 2016 when they were classified as assets held for sale and following the termination of the Alberta PPAs in March 2016.

Bruce Power results

Bruce Power results reflect our proportionate share. Comparable EBITDA and comparable EBIT are non-GAAP measures. Refer to page 8 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)	2018	2017	2016
Equity income included in comparable EBITDA and EBIT comprised of:			
Revenues[1]	**1,526**	1,626	1,491
Operating expenses	**(852)**	(846)	(870)
Depreciation and other	**(363)**	(346)	(328)
Comparable EBITDA and EBIT[2]	**311**	434	293
Bruce Power – other information			
Plant availability[3]	**87%**	90%	83%
Planned outage days	**280**	221	415
Unplanned outage days	**92**	49	76
Sales volumes (GWh)[2]	**23,486**	24,368	22,178
Realized sales price per MWh[4]	**$67**	$67	$68

1 Net of amounts recorded to reflect operating cost efficiencies shared with the IESO.
2 Represents our 48.3 per cent (2017 – 48.4 per cent; 2016 – 48.5 per cent) ownership interest in Bruce Power. Sales volumes include deemed generation.
3 The percentage of time the plant was available to generate power, regardless of whether it was running.
4 Calculation based on actual and deemed generation. Realized sales 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 2018 was 87 per cent as planned maintenance was completed on Bruce Units 1, 4 and 8 and began on Unit 3 in fourth quarter 2018, which is scheduled to be completed in first quarter 2019.

Plant availability in 2017 was 90 per cent as planned maintenance was completed on Bruce Units 3, 5 and 6. Plant availability in 2016 was 83 per cent as planned maintenance was completed on six of the eight units.

OUTLOOK

Earnings

Our 2019 comparable earnings for the Energy segment are expected to be higher than 2018 primarily due to a higher contribution from Bruce Power and incremental earnings from the completion of the Napanee power plant in Ontario, partially offset by the sale of our interests in the Cartier Wind power facilities in 2018 and the expected sale of our Coolidge generating station in 2019. Results from our natural gas storage business are expected to be lower primarily due to pipeline constraints in the Alberta market limiting access to our facilities.

Bruce Power equity income in 2019 is expected to be higher primarily due to an increased contract price to reflect the capital to be invested under the Unit 6 MCR and AM programs, as well as normal annual inflation adjustments. Planned maintenance is expected to occur on Bruce Units 2, 3 and 7 in the first half of 2019 and Unit 5 in the second half of 2019. The average plant availability percentage in 2019 is expected to be in the high 80 per cent range, comparable to 2018.

Capital spending

We spent a total of $0.7 billion in 2018 on our Energy assets, primarily on continuing construction of Napanee, and expect to spend approximately $0.1 billion in 2019.

We invested $0.5 billion in 2018 for our share of Bruce Power's life extension and maintenance capital projects and expect to invest approximately $0.5 billion in 2019.

BUSINESS RISKS

The following are risks specific to our Energy business. See page 85 for information about general risks that affect the Company as a whole, including other operational and financial risks.

Fluctuating power and natural gas market prices

Our portfolio of assets in Eastern Canada and our Coolidge generating station in Arizona are fully contracted, and are therefore not materially impacted by fluctuating spot power and natural gas prices. As these contracts expire in the long term, it is uncertain if we will be able to re-contract on similar terms and may face future commodity exposure.

Much of the physical power generation and fuel used in our Western Power operations in Alberta 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 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.

Construction and plant availability

Constructing and 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 Energy business. Unexpected outages or extended planned outages at our power plants can increase maintenance costs, lower plant output and sales revenue, 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 Canada and a regulated market in Arizona. These markets are subject to various federal, state and provincial regulations in both countries. As power markets evolve across North America, 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 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 energy and energy-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 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, additional supply from regional power transmission interconnections and new supply in the form of distributed generation. We also face competition from other power companies in Alberta and Ontario as well as in the development of greenfield power plants. To remain competitive it is also important for us to be on time and on budget with our major capital projects.

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented losses (the most directly comparable GAAP measure). See page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2018	2017	2016
Comparable EBITDA and EBIT	**(59)**	(21)	18
Specific items:			
Foreign exchange gain – inter-affiliate loan[1]	**5**	63	—
Integration and acquisition related costs – Columbia	**—**	(81)	(116)
Restructuring costs	**—**	—	(22)
Segmented losses	**(54)**	(39)	(120)

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

Corporate segmented losses increased by $15 million in 2018 compared to2017 and decreased by $81 million in 2017 compared to 2016.

Segmented losses in 2018 and 2017 included foreign exchange gains of $5 million and $63 million, respectively, on a peso-denominated inter-affiliate loan to the Sur de Texas project for our proportionate share of the project's financing. There is a corresponding foreign exchange loss included in Interest income and other on the inter-affiliate loan receivable which fully offsets this gain.

Segmented losses in 2017 and 2016 included integration and acquisition costs of $81 million and $116 million, respectively, associated with the acquisition of Columbia. Segmented losses in 2016 also included restructuring costs of $22 million. These amounts have been excluded from our calculation of comparable EBITDA and EBIT.

Comparable EBITDA decreased by $38 million in 2018 compared to 2017 and by $39 million in 2017 compared to 2016, primarily due to increased general and administrative costs.

Corporate restructuring and business transformation

In mid-2015, we commenced a business restructuring and transformation initiative to reduce overall costs and maximize the effectiveness and efficiency of our existing operations. As a result, we incurred corporate restructuring costs and recorded a provision to allow for planned severance costs in future years, as well as expected future losses under lease commitments.

Cumulatively to December 31, 2018, we have incurred costs of $86 million for employee severance and $60 million for lease commitments, net of $157 million related to costs that were recoverable through regulatory and tolling structures. We recorded additional provisions in 2018 to reflect the changes in expected future losses under lease commitments. The remaining lease commitments provision at December 31, 2018 is expected to be fully realized by 2027.

Changes in the restructuring liability were as follows:

(millions of $)	Employee Severance	Lease Commitments	Total
Restructuring liability as at December 31, 2016	36	63	99
Restructuring charges[1]	—	6	6
Accretion expense	—	1	1
Cash payments	(27)	(17)	(44)
Restructuring liability as at December 31, 2017	9	53	62
Restructuring charges[1]	—	42	42
Accretion expense	—	1	1
Cash payments	(9)	(15)	(24)
Restructuring Liability as at December 31, 2018	**—**	**81**	**81**

1 At December 31, 2018, we recorded an additional $21 million in Plant operating costs and other in the Consolidated statement of income and $21 million as a regulatory asset on the Consolidated balance sheet related to costs that are expected to be recovered through regulatory and tolling structures in future periods (2017 – $3 million and $3 million, respectively).

OTHER INCOME STATEMENT ITEMS

Interest Expense

year ended December 31 (millions of $)	2018	2017	2016
Interest on long-term debt and junior subordinated notes			
Canadian dollar-denominated	**(549)**	(494)	(452)
U.S. dollar-denominated	**(1,325)**	(1,269)	(1,127)
Foreign exchange impact	**(394)**	(379)	(366)
	(2,268)	(2,142)	(1,945)
Other interest and amortization expense	**(121)**	(99)	(114)
Capitalized interest	**124**	173	176
Interest expense included in comparable earnings	**(2,265)**	(2,068)	(1,883)
Specific items:			
Integration and acquisition related costs – Columbia	**—**	—	(115)
Risk management activities	**—**	(1)	—
Interest expense	**(2,265)**	(2,069)	(1,998)

Interest expense in 2018 increased by $196 million compared to 2017 primarily due to the net effect of:

- long-term debt and junior subordinated note issuances in 2018 and 2017, net of maturities. See the Financial condition section for further details on long-term debt
- lower capitalized interest primarily due to the completion of Grand Rapids and Northern Courier in the second half of 2017, partially offset by ongoing construction at Napanee and the recommencement of capitalization of Keystone XL costs in 2018
- higher levels of short-term borrowing
- final repayment of the Columbia acquisition bridge facilities in June 2017 resulting in lower interest and debt amortization expense.

Interest expense in 2017 increased by $71 million compared to 2016 mainly due to the net effect of:

- long-term debt and junior subordinated notes issuances in 2017 and 2016, net of maturities. Refer to the Financial condition section for further details on long-term debt
- debt assumed in the acquisition of Columbia on July 1, 2016
- lower amortization expense on debt issuance costs related to the Columbia acquisition bridge facilities, which were fully repaid in June 2017
- higher foreign exchange on interest expense related to higher levels of U.S. dollar-denominated debt
- the specific item of $115 million in 2016 included the dividend equivalent payments of $109 million on the subscription receipts issued to partially fund the Columbia acquisition and $6 million of other acquisition related costs.

Allowance for funds used during construction

year ended December 31 (millions of $)	2018	2017	2016
Allowance for funds used during construction			
Canadian dollar-denominated	**103**	174	181
U.S. dollar-denominated	**326**	259	181
Foreign exchange impact	**97**	74	57
Allowance for funds used during construction	**526**	507	419

AFUDC increased by $19 million in 2018 compared to 2017 mainly due to continued investment in Mexico projects and additional investment in and higher rates on Columbia Gas growth projects, partially offset by our decision in the second half of 2017 not to proceed with the Energy East Pipeline and lower capital expenditures in Canadian Mainline.

AFUDC increased by $88 million in 2017 compared to 2016 mainly due to continued investment in and higher rates on projects acquired as part of the 2016 Columbia acquisition, as well as continued investment in Mexico projects and the NGTL System, partially offset by the commercial in-service of Topolobampo, the completion of Mazatlán construction and our decision not to proceed with the Energy East Pipeline.

Interest income and other

year ended December 31 (millions of $)	2018	2017	2016
Interest income and other included in comparable earnings	**177**	159	71
Specific items:			
Foreign exchange loss – inter-affiliate loan	**(5)**	(63)	—
Integration and acquisition related costs – Columbia	**—**	—	6
Risk management activities	**(248)**	88	26
Interest income and other	**(76)**	184	103

In 2018, Interest income and other decreased by $260 million compared to 2017 due to the net effect of:

- unrealized losses on risk management activities in 2018 compared to unrealized gains in 2017, reflecting the strengthening of the U.S. dollar at the end of 2018. These amounts have been excluded from comparable earnings
- higher interest income combined with a lower foreign exchange loss related to an inter-affiliate loan receivable from the Sur de Texas joint venture. The corresponding interest expense and foreign exchange gain are reflected in Income from equity investments in the Mexico Natural Gas Pipelines and Corporate segments, respectively, resulting in no impact on net income. The offsetting currency-related gain and loss amounts are excluded from comparable earnings
- realized losses in 2018 compared to realized gains in 2017 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- lower recovery in 2018 related to carrying charges on Coastal GasLink project costs incurred
- $10 million recognized on the termination of the PRGT project in 2017.

In 2017, Interest income and other increased by $81 million compared to 2016 due to the net effect of:

- higher unrealized gains on risk management activities in 2017. These amounts have been excluded from comparable earnings
- recovery of $32 million related to carrying charges on Coastal GasLink project costs incurred, and amounts recognized on the termination of the PRGT project in 2017
- foreign exchange impact on the translation of foreign currency denominated working capital balances
- lower realized gains in 2017 compared to 2016 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- higher interest income along with a $63 million foreign exchange loss in 2017 related to an inter-affiliate loan receivable from the Sur de Texas joint venture. The corresponding interest expense and foreign exchange gain are reflected in Income from equity investments in the Mexico Natural Gas Pipelines and Corporate segments, respectively, resulting in no impact on net income. The offsetting currency-related gain and loss amounts are excluded from comparable earnings.

Income tax (expense)/recovery

year ended December 31 (millions of $)	2018	2017	2016
Income tax expense included in comparable earnings	**(693)**	(839)	(841)
Specific items:			
MLP regulatory liability write-off	**115**	—	—
U.S. Tax Reform	**52**	804	—
Bison asset impairment	**44**	—	—
Sales of U.S. Northeast power generation assets	**27**	(177)	(29)
Tuscarora goodwill impairment	**5**	—	—
U.S. Northeast power marketing contracts	**1**	—	—
Gain on sale of Cartier Wind power facilities	**(27)**	—	—
Bison contract terminations	**(8)**	—	—
Energy East impairment charge	**—**	302	—
Integration and acquisition related costs – Columbia	**—**	22	10
Gain on sale of Ontario solar assets	**—**	9	—
Keystone XL income tax recoveries	**—**	7	28
Keystone XL asset costs	**—**	6	10
Ravenswood goodwill impairment	**—**	—	429
Alberta PPA terminations and settlement	**—**	—	88
Restructuring costs	**—**	—	6
TC Offshore loss on sale	**—**	—	1
Risk management activities	**52**	(45)	(54)
Income tax (expense)/recovery	**(432)**	89	(352)

Income tax expense included in comparable earnings in2018 decreased by $146 million in 2018 compared to 2017 primarily due to lower income tax rates as a result of U.S. Tax Reform and lower flow-through income taxes in Canadian rate-regulated pipelines, partially offset by income taxes recorded on higher pre-tax earnings.

Income tax expense included in comparable earnings in2017 remained consistent with 2016 and reflects the net impact of higher comparable earnings, changes in the proportion of income earned between Canadian and foreign jurisdictions and changes in flow-through taxes in regulatory operations.

Net loss/(income) attributable to non-controlling interests

year ended December 31 (millions of $)	2018	2017	2016
Net income attributable to non-controlling interests included in comparable earnings	**(315)**	(238)	(257)
Specific items:			
Bison impairment	**538**	—	—
Tuscarora goodwill impairment	**59**	—	—
Bison contract terminations	**(97)**	—	—
Integration and acquisition related costs – Columbia	**—**	—	5
Net loss/(income) attributable to non-controlling interests	**185**	(238)	(252)

Net loss/(income) attributable to non-controlling interests decreased by $423 million in 2018 compared to 2017 due to the net effect of:

- a $538 million charge related to the non-controlling interests portion of a $722 million Bison asset impairment charge recorded by TC PipeLines, LP
- a $59 million charge related to the non-controlling interests portion of a $79 million Tuscarora goodwill impairment charge recorded by TC PipeLines, LP
- $97 million in income related to the non-controlling interests portion of Bison contract termination payments of $130 million received from certain customers and recorded by TC PipeLines, LP.

On consolidation, we recorded the non-controlling interests' 74.5 per cent of these transactions. These items have been excluded in the calculation of comparable earnings. Refer to the Critical accounting estimates section for more information on our goodwill and asset impairment testing.

In 2018, net income attributable to non-controlling interests included in comparable earnings increased by $77 million compared to 2017 primarily due to higher earnings in TC PipeLines, LP, partially offset by our acquisition of the remaining outstanding publicly held common units of CPPL in February 2017.

Net income attributable to non-controlling interests and net income attributable to non-controlling interests included in comparable earnings decreased by $14 million and $19 million, respectively, in 2017 compared to 2016 primarily due to our acquisition of the remaining outstanding publicly held common units of CPPL in February 2017.

Preferred share dividends

year ended December 31 (millions of $)	2018	2017	2016
Preferred share dividends	**(163)**	(160)	(109)

Preferred share dividends of $163 million in 2018 were consistent with 2017. Preferred share dividends in 2017 increased by $51 million compared to 2016 due to the issuance of Series 13 and Series 15 preferred shares in April 2016 and November 2016, respectively. Refer to the Financial condition section for more information.

Financial condition

We strive to maintain strong financial capacity and flexibility in all parts of the economic cycle. We rely on our operating cash flow to sustain our business, pay dividends and fund a portion of our growth. In addition, we access capital markets 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 AIF available on SEDAR (www.sedar.com).

We believe we have the financial capacity to fund our existing capital program through predictable and growing cash flow from operations, access to capital markets, portfolio management, cash on hand, substantial committed credit facilities and, if deemed appropriate, our Corporate ATM program and DRP. Annually, in fourth quarter, we renew and extend our credit facilities as required.

In light of the 2018 FERC Actions, further drop downs of assets into TC PipeLines, LP are currently considered to not be a viable funding lever. In addition, the TC PipeLines, LP ATM program ceased to be utilized effective March 2018. It is yet to be determined if and when in the future these might be restored as competitive financing options. Refer to the 2018 FERC Actions section for further information.

Balance sheet analysis

Our total assets at December 31, 2018 were $98.9 billion compared to $86.1 billion at December 31, 2017 primarily reflecting our 2018 capital spending program.

At December 31, 2018, our total liabilities were $67.9 billion compared to $59.2 billion at December 31, 2017 mainly reflecting a net increase in long-term debt, primarily as a result of issuances of senior and medium-term notes, net of maturities, and higher notes payable.

Total assets and total liabilities both increased due to a stronger U.S. dollar at December 31, 2018 compared to December 31, 2017.

Our equity at December 31, 2018 was $31.0 billion compared to $26.9 billion at December 31, 2017. The increase is primarily due to common shares issued under our DRP and Corporate ATM program, as well as annual net income and OCI attributable to controlling interests.

Consolidated capital structure

The following table summarizes the components of our capital structure.

at December 31 (millions of $, unless otherwise noted)	**2018**	**Per cent of total**	**2017**	**Per cent of total**
Notes payable	**2,762**	**3**	1,763	3
Long-term debt, including current portion	**39,971**	**50**	34,741	50
Cash and cash equivalents	**(446)**	**(1)**	(1,089)	(2)
Debt	**42,287**	**52**	35,415	51
Junior subordinated notes	**7,508**	**9**	7,007	10
Preferred shares	**3,980**	**5**	3,980	6
Common shareholders' equity[1]	**27,013**	**34**	22,911	33
	80,788	**100**	69,313	100

1 Includes non-controlling interests.

At February 11, 2019 we had unused capacity of $2.7 billion, $1.0 billion, and US$2.1 billion under our various equity, Canadian debt and U.S. debt 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, 2018.

Cash flow

The following tables summarize the consolidated cash flows of our business.

year ended December 31 (millions of $)	2018	2017	2016
Net cash provided by operations	**6,555**	5,230	5,069
Net cash used in investing activities	**(10,019)**	(3,699)	(18,783)
	(3,464)	1,531	(13,714)
Net cash provided by/(used in) financing activities	**2,748**	(1,419)	14,007
	(716)	112	293
Effect of foreign exchange rate changes on cash and cash equivalents	**73**	(39)	(127)
(Decrease)/increase in cash and cash equivalents	**(643)**	73	166

At December 31, 2018, our current assets totaled $5.1 billion (2017 – $4.7 billion) and current liabilities amounted to $12.9 billion (2017 – $9.9 billion), leaving us with a working capital deficit of $7.8 billion compared to a deficit of $5.2 billion at December 31, 2017. 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 flow from operations
- approximately $11.8 billion of unutilized, unsecured credit facilities
- our access to capital markets, including through our DRP and Corporate ATM programs, if deemed appropriate.

Cash provided by operating activities

year ended December 31 (millions of $)	2018	2017	2016
Net cash provided by operations	**6,555**	5,230	5,069
Increase/(decrease) in operating working capital	**102**	273	(248)
Funds generated from operations	**6,657**	5,503	4,821
Specific items:			
Bison contract terminations	**(122)**	—	—
U.S. Northeast power marketing contracts	**1**	—	—
Integration and acquisition related costs – Columbia	**—**	84	283
Keystone XL asset costs	**—**	34	52
Net (gain)/loss on sales of U.S. Northeast power generation assets	**(14)**	20	15
Comparable funds generated from operations	**6,522**	5,641	5,171
Dividends on preferred shares	**(158)**	(155)	(100)
Distributions to non-controlling interests	**(225)**	(283)	(279)
Non-recoverable maintenance capital expenditures	**(254)**	(240)	(310)
Comparable distributable cash flow	**5,885**	4,963	4,482
Comparable distributable cash flow per common share	**$6.52**	$5.69	$5.91

Net cash provided by operations

The year-over-year increases in net cash provided by operations are primarily due to the net effect of higher earnings (as discussed in Financial highlights on page 21), the recovery of higher depreciation as approved by the NEB in the Mainline NEB 2018 Decision and NGTL's 2018-2019 Settlement as well as the amount and timing of working capital changes.

Comparable funds generated from operations

Comparable funds generated from operations, a non-GAAP measure, helps us assess the cash generating ability of our operations by excluding the timing effects of working capital changes as well as the cash impact of our specific items. See page 8 for more information about non-GAAP measures.

Comparable funds generated from operations increased by $881 million in 2018 compared to 2017, primarily due to higher comparable earnings adjusted for non-cash items and the cash impact of specific items as well as the recovery of higher depreciation for both the Canadian Mainline and the NGTL System as described above.

Comparable funds generated from operations increased by $470 million in 2017 compared to 2016 mainly due to higher comparable EBITDA (excluding income from equity investments) and higher distributions from our equity investments, partially offset by higher interest expense and increased funding of our employee post-retirement benefit plans.

Comparable distributable cash flow

Comparable distributable cash flow, a non-GAAP measure, helps us assess the cash available to common shareholders before capital allocation. Refer to page 8 for more information on non-GAAP measures we use.

The year-over-year increases in comparable distributable cash flow primarily reflect higher comparable funds generated from operations, as described above as well as the impact of the reduction to TC PipeLines, LP's quarterly distribution to common unitholders beginning in first quarter 2018. Comparable distributable cash flow per common share for the year ended December 31, 2018 also includes the dilutive effect of common shares issued in 2017 and 2018.

In 2018, our determination of comparable distributable cash flow has been revised to exclude the deduction of maintenance capital expenditures for assets for which we have the ability to recover these costs in pipeline tolls. Comparative periods presented in the table above have been adjusted accordingly. We believe that including only non-recoverable maintenance capital expenditures in the calculation of distributable cash flow best depicts the cash available for reinvestment or distribution to shareholders. For our rate-regulated Canadian and U.S. natural gas pipelines, we have the opportunity to recover and earn a return on maintenance capital expenditures through current and future tolls. Tolling arrangements in our liquids pipelines provide for the recovery of maintenance capital expenditures. Therefore, we have not deducted the recoverable maintenance capital expenditures for these businesses in the calculation of comparable distributable cash flow.

Cash used in investing activities

year ended December 31 (millions of $)	2018	2017	2016
Capital spending			
Capital expenditures	**(9,418)**	(7,383)	(5,007)
Capital projects in development	**(496)**	(146)	(295)
Contributions to equity investments	**(1,015)**	(1,681)	(765)
	(10,929)	(9,210)	(6,067)
Acquisitions, net of cash acquired	**—**	—	(13,608)
Proceeds from sale of assets, net of transaction costs	**614**	4,683	6
Reimbursement of costs related to capital projects in development	**470**	634	—
Other distributions from equity investments	**121**	362	727
Deferred amounts and other	**(295)**	(168)	159
Net cash used in investing activities	**(10,019)**	(3,699)	(18,783)

Net cash used in investing activities increased from$3.7 billion in 2017 to $10.0 billion in 2018 primarily as a result of proceeds received on the sales of our U.S. Northeast power generation assets and solar assets in 2017, along with higher capital expenditures and spending on capital projects in development in 2018. This was partially offset by the proceeds from the sale of our interests in the Cartier Wind power facilities.

Net cash used in investing activities decreased from$18.8 billion in 2016 to $3.7 billion in 2017 mainly due to the net effect of:

- the 2016 acquisitions of Columbia and Ironwood
- higher capital spending in 2017
- proceeds from the sales of our U.S. Northeast power generation assets and solar assets in 2017
- recovery of PRGT project costs.

Capital spending[1]

The following table summarizes capital spending by segment.

year ended December 31 (millions of $)	2018	2017	2016
Canadian Natural Gas Pipelines	**2,478**	2,181	1,525
U.S. Natural Gas Pipelines	**5,771**	3,830	1,522
Mexico Natural Gas Pipelines	**797**	1,954	1,142
Liquids Pipelines	**581**	529	1,137
Energy	**1,257**	675	708
Corporate	**45**	41	33
	10,929	9,210	6,067

1 Capital spending includes capacity capital expenditures, maintenance capital expenditures, capital projects in development and contributions to equity investments.

Capital expenditures

Our 2018 and 2017 capital expenditures were incurred primarily for the expansion of the Columbia Gas, Columbia Gulf, NGTL System and Canadian Mainline natural gas pipelines as well as the construction of the Napanee power generating facility and Mexico natural gas pipelines.

Our 2016 capital expenditures were incurred mainly for expanding the Columbia Gas and Columbia Gulf pipelines from their acquisition date along with the NGTL System, Canadian Mainline and ANR, plus construction of our Mexico natural gas pipelines, Northern Courier pipeline and the Napanee power generating facility.

Capital projects in development

Costs incurred during 2018 on capital projects in development were predominantly attributable to spending on Keystone XL and Coastal GasLink. Spending in 2017 and 2016 primarily related to the Energy East and LNG-related pipeline projects.

Contributions to equity investments

Contributions to equity investments decreased in 2018 compared to 2017 mainly due to lower annual investment in Sur de Texas, Northern Border and the completion of Grand Rapids in 2017, partially offset by higher investment in Millennium and Bruce Power.

Contributions to equity investments increased in 2017 compared to 2016 primarily due to our investments in Sur de Texas, Bruce Power and Northern Border, partially offset by decreased contributions to Grand Rapids which went in service in August 2017.

2018 and 2017 contributions to equity investments include our proportionate share of Sur de Texas debt financing.

Sales of assets

In October 2018, we completed the sale of our interests in the Cartier Wind power facilities in Québec for proceeds of approximately $30 million, before post-closing adjustments.

In 2017, we completed the following transactions:

- sold Ravenswood, Ironwood, Kibby Wind and Ocean State Power for proceeds of approximately US$2.029 billion, before post-closing adjustments
- sold TC Hydro for proceeds of approximately US$1.07 billion, before post-closing adjustments
- sold our Ontario solar assets for proceeds of approximately $541 million, before post-closing adjustments.

Reimbursement of costs related to capital projects in development

In November 2018, we received $0.5 billion in accordance with provisions in the agreements with the LNG Canada joint venture participants allowing them to reimburse us for their share of pre-FID costs.

In July 2017, we were notified that PNW LNG would not be proceeding with their LNG project. As a result, in October 2017, we received a payment of $0.6 billion from Progress Energy for full recovery of our PRGT project costs plus carrying charges.

Other distributions from equity investments

Other distributions from equity investments primarily reflects our proportionate share of Bruce Power financings undertaken to fund its capital program and make distributions to its partners. In 2018, Bruce Power issued senior notes in the capital markets which resulted in such distributions totaling $121 million being received by us. In 2017, Bruce Power issued senior notes in the capital markets which resulted in $362 million being received by us.

Cash provided by/(used in) financing activities

year ended December 31 (millions of $)	2018	2017	2016
Notes payable issued/(repaid), net	**817**	1,038	(329)
Long-term debt issued, net of issue costs	**6,238**	3,643	12,333
Long-term debt repaid	**(3,550)**	(7,085)	(7,153)
Junior subordinated notes issued, net of issue costs	**—**	3,468	1,549
Dividends and distributions paid	**(1,954)**	(1,777)	(1,815)
Common shares issued, net of issue costs	**1,148**	274	7,747
Common shares repurchased	**—**	—	(14)
Preferred shares issued, net of issue costs	**—**	—	1,474
Partnership units of TC PipeLines, LP issued, net of issue costs	**49**	225	215
Common units of Columbia Pipelines Partners LP acquired	**—**	(1,205)	—
Net cash provided by/(used in) financing activities	**2,748**	(1,419)	14,007

Net cash provided by financing activities increased by $4.2 billion in 2018 compared to 2017 primarily due to issuances of long-term debt (net of long-term debt repaid) and common shares and the acquisition of CPPL in 2017, partially offset by junior subordinated notes issued in 2017.

Net cash provided by financing activities decreased by $15.4 billion in 2017 compared to 2016 primarily due to significant financing activity, including common share issuances, associated with funding the US$10.3 billion cash acquisition of Columbia in 2016 and the US$921 million acquisition of the outstanding publicly held common units of CPPL in 2017.

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

Long-term debt issued

The following table outlines significant debt issuances in 2018:

(millions of Canadian $, unless otherwise noted) Company	Issue date	Type	Maturity Date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	October 2018	Senior Unsecured Notes	March 2049	US 1,000	5.10%
	October 2018	Senior Unsecured Notes	May 2028	US 400	4.25%
	July 2018	Medium Term Notes	July 2048	800	4.18%
	July 2018	Medium Term Notes	March 2028	200	3.39%
	May 2018	Senior Unsecured Notes	May 2048	US 1,000	4.875%
	May 2018	Senior Unsecured Notes	May 2038	US 500	4.75%
	May 2018	Senior Unsecured Notes	May 2028	US 1,000	4.25%
NORTH BAJA PIPELINE, LLC					
	December 2018	Unsecured Term Loan	December 2021	US 50	Floating

The net proceeds of the above debt issuances were used for general corporate purposes, to fund our capital program and to prefund 2019 senior note maturities.

Long-term debt repaid

The following table outlines significant debt repaid in 2018 and early 2019:

(millions of Canadian $, unless otherwise noted)				
Company	**Retirement date**	**Type**	**Amount**	**Interest rate**
TRANSCANADA PIPELINES LIMITED				
	January 2019	Senior Unsecured Notes	US 750	7.125%
	January 2019	Senior Unsecured Notes	US 400	3.125%
	August 2018	Senior Unsecured Notes	US 850	6.50%
	March 2018	Debentures	150	9.45%
	January 2018	Senior Unsecured Notes	US 500	1.875%
	January 2018	Senior Unsecured Notes	US 250	Floating
TC PIPELINES, LP				
	December 2018	Unsecured Term Loan	US 170	Floating
COLUMBIA PIPELINE GROUP, INC.				
	June 2018	Senior Unsecured Notes	US 500	2.45%

For more information about long-term debt and junior subordinated notes issued and long-term debt repaid in 2018, 2017 and 2016, refer to our 2018 annual Consolidated financial statements.

Dividend reinvestment plan

On July 1, 2016, we re-initiated the issuance of common shares from treasury under our DRP. Under this plan, eligible holders of common and preferred shares of TransCanada can reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares. Common shares are issued from treasury at a discount of two per cent to market prices over a specified period. On dividends declared in 2018, the participation rate by common shareholders was approximately 35 per cent (2017 – 36 per cent), resulting in $870 million (2017 – $787 million) reinvested in common equity under the program.

TransCanada's Corporate ATM Program

In June 2017, we established an ATM program that allows us to issue common shares from treasury from time to time, at the prevailing market price, when sold through the TSX, the NYSE, or any other existing trading market for TransCanada common shares in Canada or the United States. The ATM program, which is effective for a 25-month period, was initially established with an aggregate gross sales limit of $1.0 billion or the U.S. dollar equivalent. In June 2018, we replenished the capacity available under our existing ATM program to allow for the issuance of additional common shares from treasury having an aggregate gross sales price of up to $1.0 billion. The Corporate ATM program, as amended, is effective to July 23, 2019, and may be utilized at our discretion, if and as required, based on the spend profile of our capital program and relative cost of other funding options.

In 2018, 20 million common shares (2017 – 3.5 million common shares) were issued under the Corporate ATM program at an average price of $56.13 per share (2017 – $63.03 per share) for proceeds of $1.1 billion (2017 – $216 million), net of approximately $10 million (2017 – $2 million) of related commissions and fees. Subsequent to the issuances in 2017 and 2018 under the Corporate ATM program, an aggregate gross sales limit of $656 million or its U.S. dollar equivalent remains available for issuance.

Common units of Columbia Pipeline Partners LP

On February 17, 2017, we acquired all outstanding publicly held common units of CPPL at a price of US$17.00 and a stub period distribution payment of US$0.10 per common unit for an aggregate transaction value of US$921 million. As this was a transaction between entities under common control, it was recognized in equity.

TC PipeLines, LP

ATM equity issuance program

Under the TC PipeLines, LP ATM program, TC PipeLines, LP is authorized, from time to time, to offer and sell common units through ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed upon by TC PipeLines, LP and by one or more of its agents. Our ownership interest in TC PipeLines, LP decreases as a result of equity issuances under the TC PipeLines, LP ATM program.

During 2018, 0.7 million (2017 – 3.1 million) common units were issued under the TC PipeLines, LP ATM program generating net proceeds of approximately US$39 million (2017 – US$173 million). At December 31, 2018, our ownership interest in TC PipeLines, LP was 25.5 per cent (2017 – 25.7 per cent) after issuances under the TC PipeLines, LP ATM program and resulting dilution.

In March 2018, as a result of the initially proposed 2018 FERC Actions, the TC PipeLines, LP ATM program ceased to be utilized. Following the 2018 FERC Actions that became effective September 13, 2018, it is yet to be determined if and when it might be restored as a competitive financing option.

Asset drop downs

On June 1, 2017, we closed the sale of 49.34 per cent of our 50 per cent interest in Iroquois, along with an option to sell the remaining 0.66 per cent at a later date, to TC PipeLines, LP. At the same time, we closed the sale of our remaining 11.81 per cent interest in Portland to TC PipeLines, LP. Proceeds from these transactions were US$765 million before post-closing adjustments and were comprised of US$597 million in cash and US$168 million representing a proportionate share of Iroquois and Portland debt.

Refer to the 2018 FERC Actions section for more information.

Share information

as at February 11, 2019

Common Shares	**issued and outstanding**	
	922 million	

Preferred Shares	**issued and outstanding**	**convertible to**
Series 1	9.5 million	Series 2 preferred shares
Series 2	12.5 million	Series 1 preferred shares
Series 3	8.5 million	Series 4 preferred shares
Series 4	5.5 million	Series 3 preferred shares
Series 5	12.7 million	Series 6 preferred shares
Series 6	1.3 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 13	20 million	Series 14 preferred shares
Series 15	40 million	Series 16 preferred shares

Options to buy common shares	**outstanding**	**exercisable**
	12 million	8 million

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

Dividends

year ended December 31	2018	2017	2016
Dividends declared			
per common share	**$2.76**	$2.50	$2.26
per Series 1 preferred share	**$0.8165**	$0.8165	$0.8165
per Series 2 preferred share	**$0.78835**	$0.62138	$0.60648
per Series 3 preferred share	**$0.538**	$0.538	$0.538
per Series 4 preferred share	**$0.62748**	$0.46138	$0.44648
per Series 5 preferred share	**$0.56575**	$0.56575	$0.56575
per Series 6 preferred share	**$0.69341**	$0.55275	$0.50648
per Series 7 preferred share	**$1.00**	$1.00	$1.00
per Series 9 preferred share	**$1.0625**	$1.0625	$1.0625
per Series 11 preferred share	**$0.95**	$0.95	$1.1875
per Series 13 preferred share	**$1.375**	$1.375	$1.18525
per Series 15 preferred share	**$1.225**	$1.225	$0.3323

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 11, 2019, we had a total of$12.8 billion of committed revolving and demand credit facilities, including:

Amount	Unused capacity	Borrower	Description	Matures
Committed, syndicated, revolving, extendible, senior unsecured credit facilities:				
$3.0 billion	$3.0 billion	TCPL	Supports TCPL's Canadian dollar commercial paper program and is used for general corporate purposes	December 2023
US$4.5 billion	US$4.5 billion	TCPL/TCPL USA/Columbia/TAIL	Supports TCPL and TCPL USA's U.S. dollar commercial paper programs, and is used for general corporate purposes of the borrowers, guaranteed by TCPL	December 2019
US$1.0 billion	US$1.0 billion	TCPL/TCPL USA/Columbia/TAIL	Used for general corporate purposes of the borrowers, guaranteed by TCPL	December 2021
Demand senior unsecured revolving credit facilities:				
$2.1 billion	$1.0 billion	TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity; TCPL USA facility guaranteed by TCPL	Demand
MXN$5.0 billion	MXN$5.0 billion	Mexican subsidiary	Used for Mexico general corporate purposes, guaranteed by TCPL	Demand

At February 11, 2019, our operated affiliates had an additional$0.8 billion of undrawn capacity on committed credit facilities.

Contractual obligations

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

Payments due (by period)

at December 31, 2018 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Notes payable	2,762	2,762	—	—	—
Long-term debt and junior subordinated notes	47,479	3,465	4,932	4,031	35,051
Operating leases[1]	729	74	143	130	382
Purchase obligations	8,187	2,985	3,640	372	1,190
	59,157	9,286	8,715	4,533	36,623

1 Future payments for various premises, services and equipment, less sub-lease receipts.

Notes payable

Total notes payable were $2.8 billion at the end of 2018 compared to $1.8 billion at the end of 2017.

Long-term debt and junior subordinated notes

At the end of 2018, we had $40.0 billion of long-term debt and $7.5 billion of junior subordinated notes outstanding, compared to $34.7 billion of long-term debt and $7.0 billion of junior subordinated notes at December 31, 2017.

We attempt to smooth the maturity profile of our debt. The weighted-average maturity of our long-term debt and junior subordinated notes is 20 years, with the majority of final repayments occurring beyond five years.

Interest payments

At December 31, 2018, scheduled interest payments related to our long-term debt and junior subordinated notes were as follows:

at December 31, 2018 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Long-term debt	27,447	1,941	3,593	3,163	18,750
Junior subordinated notes	28,039	416	833	834	25,956
	55,486	2,357	4,426	3,997	44,706

Operating leases

Our operating leases for premises, services and equipment expire at different times between now and 2052. Some of our operating leases include the option to renew the agreement for one to 25 years.

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, 2018 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Canadian Natural Gas Pipelines					
Transportation by others[1]	859	83	161	138	477
Capital spending[2]	4,647	1,700	2,947	—	—
U.S. Natural Gas Pipelines					
Transportation by others[1]	700	119	199	108	274
Capital spending[2]	50	50	—	—	—
Mexico Natural Gas Pipelines					
Capital spending[2]	342	287	55	—	—
Liquids Pipelines					
Capital spending[2]	406	406	—	—	—
Other	22	5	7	6	4
Energy					
Commodity purchases	91	63	28	—	—
Capital spending[2]	700	199	163	56	282
Other[3]	300	34	56	58	152
Corporate					
Capital spending[2]	70	39	24	6	1
	8,187	2,985	3,640	372	1,190

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

We are developing quality projects under our $57 billion capital program. These long-life infrastructure assets are supported by long-term commercial arrangements or regulated cost of service business models and, once completed, are expected to generate significant growth in earnings and cash flow.

Our $57 billion capital program is comprised of $36.6 billion of secured projects and $20.7 billion of projects under development, each of which are subject to key commercial or regulatory approvals. The portfolio is expected to be financed through our growing internally generated cash flow 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 the funding options below, as deemed appropriate:

- common shares issued under our DRP
- common shares issued under our Corporate ATM program
- discrete common equity issuances.

GUARANTEES

Sur de Texas

We and our partner on the Sur de Texas pipeline, IEnova, have jointly guaranteed the financial performance of this entity. Such agreements include a guarantee and a letter of credit which are primarily related to construction services and the delivery of natural gas. The guarantees have terms ranging to 2020.

At December 31, 2018, our share of potential exposure under the Sur de Texas pipeline guarantees was estimated to be $183 million. The carrying amount of the guarantees was approximately $1 million.

Bruce Power

We and our partner, BPC Generation Infrastructure Trust, have each severally guaranteed a Bruce Power contingent financial obligation related to a lease agreement. The Bruce Power guarantee has a term to 2021.

At December 31, 2018, our share of the potential exposure under the Bruce Power guarantee was estimated to be $88 million. The carrying amount of the guarantee was nil.

Other jointly owned entities

We and our partners in certain other jointly owned entities have also guaranteed (jointly, severally, or jointly and severally) 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 2059.

Our share of the potential exposure under these assurances was estimated at December 31, 2018 to be $104 million. The carrying amount of these guarantees was approximately $11 million. In some 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 PLANS

In 2019, we expect to make funding contributions of approximately $113 million for the defined benefit pension plans, approximately $7 million for other post-retirement benefit plans and approximately $61 million for the savings plan and defined contribution pension plans. In addition, we expect to provide a $17 million letter of credit to the Canadian defined benefit plan for solvency funding requirements.

In 2018, we made funding contributions of $103 million to our defined benefit pension plans, $23 million for the other post-retirement benefit plans and $59 million for the savings plan and defined contribution pension plans. We also provided a $17 million letter of credit to the Canadian defined benefit plan for solvency funding requirements.

Outlook

The next actuarial valuation for our pension and other post-retirement benefit plans will be carried out as at January 1, 2019. Based on current market conditions, we expect funding requirements for these plans to approximate 2018 levels for several years. This will allow us to amortize solvency deficiencies in the plans, in addition to normal funding costs.

Our net benefit cost for our defined benefit and other post-retirement plans decreased to $74 million in 2018 from $106 million in 2017 mainly due to higher expected returns on plan assets.

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.

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 process that identifies risks that could materially impact the achievement of our strategic objectives.

Our Board of Directors' Governance Committee oversees our enterprise risk management activities, which includes ensuring appropriate management systems are in place to identify and manage our risks, including adequate Board oversight of our risk management policies, programs and practices. Other Board committees oversee specific types of risk:

- the Human Resources Committee oversees executive resourcing, organizational capabilities and compensation risk to ensure compensation practices align with our overall business strategy
- the HSSE Committee oversees operational, health, safety, sustainability and environmental risk
- the Audit Committee oversees management's role in managing financial risk.

Our executive leadership team is accountable for developing and implementing risk management plans and actions, and effective risk management is reflected in their compensation.

The following is a summary of certain general risks that affect our company and are being continuously monitored. Risks specific to each operating business segment can be found in each business segment discussion.

Risk and Description	Impact	Monitoring and Mitigation
Business interruption		
Operational risks, including equipment malfunctions and breakdowns, labour disputes, or natural disasters and other catastrophic events, including those related to climate change, acts of terror and sabotage.	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 flow and financial position. Certain events could lead to risk of injury and environmental damage.	We have TOMS that includes our corporate health, safety, sustainability, environment and asset integrity programs to prevent incidents and protect people, the environment and our assets. TOMS includes incident, emergency and crisis management programs to ensure TransCanada can effectively respond to operational risk 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 these risks, but insurance does not cover all events in all circumstances.
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 cyber security awareness program for employees. 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 Indigenous communities, landowners, governments and government agencies, and environmental non-governmental organizations. Inadequately managing expectations and issues important to stakeholders, including those related to climate change, could affect our reputation and our ability to operate and grow, as well as our access to and cost of capital.	Our reputation with stakeholders, including Indigenous communities, can have a significant impact on our operations and projects, infrastructure development and overall reputation. Should investors develop negative perceptions regarding our energy infrastructure business, future access to investment capital could be negatively impacted.	Our four core values – safety, integrity, responsibility and collaboration – are at the heart of our commitment to stakeholder engagement, and guide us in our interactions with stakeholders. We also have specific stakeholder programs and policies that set requirements, assess risks and facilitate compliance with legal and policy requirements.
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 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.	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 keeping them apprised of developments in our business and factually communicating our prospects, risks and challenges.
Capital allocation strategy		
To be competitive, we must offer energy infrastructure services in supply and demand areas, and for forms of energy that are attractive to customers.	Should alternative lower-carbon forms of energy result in decreased demand for our current services, the value of our long-lived energy infrastructure assets could be negatively impacted.	We have a diverse portfolio of assets and we utilize portfolio management to divest of non-strategic assets. We conduct analyses to identify resilient supply basins as part of our energy fundamentals and strategic development reviews. We also monitor the development of innovative technologies to inform our capital allocation strategy.
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, ensuring timely and on budget execution. 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.

Health, safety, sustainability and environment

The Board's HSSE Committee oversees operational risk, people and process safety, 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 which is used to capture, organize, document, monitor and improve our related policies, programs and procedures.

Our management system is modeled after international standards, conforms to external industry consensus standards and voluntary programs, and complies with applicable legislative requirements. It follows a continuous improvement cycle organized into four key areas:

- planning – risk and regulatory assessment, objective and target setting, defining roles and responsibilities
- implementing – development and implementation of programs, procedures and standards to manage operational risk
- reporting – incident reporting and investigation, and performance monitoring
- action – assurance activities and review of performance by management.

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

- overall HSSE corporate governance
- operational performance and preventive maintenance metrics
- asset integrity programs
- emergency preparedness, incident response and evaluation
- people and process safety performance metrics
- our Environment Program
- 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 related risks which may adversely impact TransCanada
- sustainability matters, including social, environmental and climate-change related matters
- management's approach to voluntary public disclosure on HSSE matters.

Health and safety

The safety of our employees, contractors and the public, as well as the integrity of our pipeline and energy infrastructure, is a top priority. All assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are placed in service only after all necessary requirements have been satisfied.

In 2018, we spent $1.3 billion for pipeline integrity on the natural gas and liquids pipelines we operate, a $0.3 billion increase over 2017 in part due to increased capital spending in Canada, increased integrity activities on Columbia assets, and integrity work related to our Keystone U.S. pipeline. 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 NEB-regulated pipelines are generally treated on a flow-through basis and, as a result, these expenditures generally have no impact on our earnings. Similarly, under Keystone 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.

Spending associated with process safety and various integrity programs for the Energy assets we operate is used to minimize risk to employees, the public, equipment, and surrounding environment, and to prevent disruptions to serving the energy needs of our customers.

As described in the Business interruption section above, we have a set of procedures in place to manage our response to natural disasters which include catastrophic events such as forest fires, tornadoes, earthquakes, floods, volcanic eruptions and hurricanes. The procedures, which are included in our Emergency Management Program, are designed to help protect the health and safety of our employees, minimize risk to the public and limit the potential for adverse effects on the environment.

Environmental risk, compliance and liabilities

We maintain an Environment Program to minimize potentially adverse environmental impacts. This program identifies our requirements to proactively and systematically manage environmental hazards and risks throughout the lifecycle of our assets.

Our primary sources of risk related to the environment include:

- changing regulations and costs associated with our emissions of air pollutants and GHG
- 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
- conformance and compliance with corporate and regulatory policies and requirements as well as new regulations.

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 to ensure compliance with all environmental requirements. We routinely monitor proposed changes in environmental policy, legislation and regulation, and 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.

On November 28, 2017, in connection with the line break experienced on the Keystone Pipeline System near Amherst, South Dakota on November 16, 2017, PHMSA issued a Correction Action Order (the "Amherst CAO") directing us to, among other things, repair the pipeline in accordance with an approved repair plan, return the pipeline to service in accordance with an approved return to service plan, operate the affected section of the pipeline at a reduced operating pressure until further directed and facilitate an investigation into the cause of the incident. The pressure restriction imposed by PHMSA was subsequently lifted on May 1, 2018. We are fully cooperating with PHMSA on all matters relating to this incident as well as with the SDDENR on site remediation. We have completed remediation of all contaminated soil and groundwater and all soil confirmation and groundwater sample results meet required standards. SDDENR issued a closure letter on January 3, 2019. Surface reclamation and revegetation were completed in 2018, and this segment of the right-of-way has been returned to the Keystone Pipeline System right-of-way vegetation management program. On January 29, 2019, we received confirmation from PHMSA that we have complied with the terms of the Amherst CAO and the case is now closed.

On June 7, 2018, there was a natural gas pipeline rupture on a section of Columbia Gas located on Nixon Ridge in Marshall County, West Virginia. The pipeline was placed back in service on July 15, 2018. TransCanada received a Notice of Proposed Safety Order from PHMSA for this matter on July 9, 2018, and responded on August 7, 2018. We expect to receive a final order outlining the final remedial requirements in due course.

Other than the Amherst CAO and the pending Proposed Safety Order for the section of Columbia Gas located on Nixon Ridge, 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, 2018, accruals related to these obligations totaled $32 million (2017 – $34 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 risk

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 2018, we incurred $62 million (2017 – $63 million) of expense under existing carbon pricing programs. Across North America, there are a variety of new and evolving initiatives 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. We support transparent climate change policies that promote sustainable and economically responsible natural resource development. We expect that, over time, most of our assets will be subject to some form of regulation to manage GHG emissions. Changes in regulations may result in higher operating costs or other expenses, or higher capital expenditures to comply with possible new regulations.

Existing policies

Canadian Jurisdiction

- Environment and Climate Change Canada (ECCC) issued the final Methane Reduction Regulation on April 26, 2018. The regulations detail requirements to reduce methane emissions through operational and capital modifications. There are multiple timeframes for compliance depending on the provision, beginning in 2020. Alberta, British Columbia and Saskatchewan have drafted their own methane regulations which take the place of the federal regulation in those jurisdictions. However, for the federally regulated facilities in these jurisdictions, the federal methane regulation will be applicable. For most of TransCanada's Canadian pipeline assets, it is likely that the federal regulation will be applicable. Compliance will involve equipment retrofits, frequent leak detection and repair surveys and measurements to quantify emission reductions and associated annual reporting. Power facilities are not affected by this regulation
- B.C. has a tax on GHG emissions from fossil fuel combustion. We recover the compliance costs through the tolls our customers pay
- in Alberta, the CCIR replaced the SGER effective January 1, 2018. This regulation requires established industrial facilities with GHG emissions above a certain threshold to reduce their emissions below an intensity baseline. The CCIR covers our natural gas pipelines and Energy assets in Alberta. Canadian natural gas pipeline compliance costs are recovered through regulated tolls. A portion of the compliance costs for the Energy 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, the 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 natural gas pipeline facilities in Québec are also subject to this program and compliance instruments have been purchased in order to comply with the requirements of this initiative
- Ontario repealed its cap-and-trade program in 2018. The compliance credits purchased under the previous cap-and-trade program have been retired by the new government. With the repeal of the cap-and-trade program, Ontario does not have carbon pricing regulation, therefore, TransCanada's electricity and pipeline facilities in this jurisdiction are subject to the Canadian Federal OBPS as of January 1, 2019. Federal OBPS applies to electric generation facilities with annual emissions greater than 50,000 tonnes of CO_2 equivalent. At this time we do not anticipate any material impact to the financial performance of our Ontario natural gas facilities as a result of this program.

U.S. Jurisdiction

- the U.S. Environmental Protection Agency (EPA) published regulations related to fugitive methane emissions for new and modified compressor stations in the natural gas transmission and storage sector in 2015. In 2017, the EPA indicated its intention to reconsider this regulation. In 2018, with direction from the Trump administration, the EPA is working on reducing the requirements of this regulation
- on March 23, 2017, the California Air Resources Board published regulations related to monitoring and repairing methane leaks. Tuscarora Gas Transmission facilities are required to comply with these regulations
- Washington State adopted emission standards to cap and reduce GHGs from certain stationary sources in September 2016. Some GTN compressor stations in Washington are potentially impacted by the standards beginning in 2020
- the Pennsylvania Department of Environmental Protection has adopted new operating permits for oil and gas facilities that include numerous requirements including methane leak detection and repair
- California has a GHG cap-and-trade program under the WCI GHG emissions market. In California, TransCanada has costs associated with the cap-and-trade program with respect to our electricity marketing activities.

Mexico Jurisdiction

- on November 6, 2018, the Government of Mexico published a new regulation that established guidelines for the prevention and control of methane emissions in the hydrocarbon sector, which will impact our Mexico natural gas pipelines. Companies will have one year to comply with the regulations which include equipment requirements such as installation of vapor recovery systems and detection and repair of leaks, as well as administrative requirements including the identification of methane emissions and implementation of a program for emissions reporting.

Anticipated policies

- the Government of Canada has finalized a Federal plan to have carbon pricing in place in all Canadian jurisdictions. ECCC is in the process of finalizing the Federal OBPS regulation to impose carbon pricing for larger industrial facilities and will set federal benchmarks for GHG emissions for various industry sectors. This new federal regulation will apply to the provinces of Ontario, Manitoba, Saskatchewan, and New Brunswick as those jurisdictions do not currently have a provincial plan in place for carbon pricing or meet the criteria of the Federal plan. This may result in increased costs for current pipeline and energy facilities in those jurisdictions
- the Government of Canada has proposed a Federal plan, the Clean Fuel Standard (CFS), to implement a single national standard encompassing all fuel types and applications. As part of the CFS, compressor station electrification is proposed by the Federal Government as a mechanism to reduce natural gas transmission GHG emissions. This could have negative impacts to our Canadian natural gas compression assets. Efforts to influence this policy are being managed through CEPA and CGA. Different components of the CFS regulations are expected to be released through 2019
- the Government of Saskatchewan has announced that certain large industrial emitters will be subject to a provincially proposed carbon pricing system based on an OBPS approach, which has potential to impact our Canadian natural gas pipelines in that province. This proposed system only partially meets the Federal plan and, therefore, the Federal OBPS will apply to emission sources not covered by the proposed system, including electricity generation and natural gas pipelines
- New York State announced its intent to adopt regulations to reduce methane from existing, new and modified facilities. New York has not yet proposed regulations, but the Governor announced the State's plan to achieve its clean energy goals by 2030, which includes a 40% reduction from 1990 emissions levels. Impacts to our facilities are dependent on the specifics of the regulations once they are proposed, but it is likely that our compression facilities in New York State would be affected
- Maryland announced its intent to establish fugitive methane regulations for compressor stations. Maryland has been working with operators, including TransCanada, to develop regulations to reduce greenhouse gases. TransCanada has only one compressor station in Maryland, and it is electric, therefore, no significant impact is expected.

Changes to Environmental Assessment Legislation

The majority of TransCanada's natural gas and liquids pipeline assets in Canada are federally regulated by the NEB under the National Energy Board Act while others are provincially regulated in Alberta and B.C. New projects that will be regulated by the NEB require an environmental assessment, overseen by the NEB and consistent with the Canadian Environmental Assessment Act. Our assets in operation do not fall under the Canadian Environmental Assessment Act. All assets may be subject to the Federal Navigation Protection Act and the Fisheries Act. In Canada, there are several evolving policy initiatives at the federal level related to environmental impact assessment. We actively monitor and submit comments to regulators as these new and evolving initiatives are undertaken.

In February 2018, the Government of Canada released Bill C-69, to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other acts. Under the bill, it appears that major projects will have a longer, more complex regulatory approval process, and introduces significant potential uncertainty for new projects in Canada.

In February 2018, the Government of Canada also released Bill C-68, an Act to amend the Fisheries Act and other acts in consequence. The bill leaves a number of details unaddressed, such as project permitting process, requirements, timelines and how Indigenous concerns will be managed, and could have cost and schedule impacts for projects.

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 flow 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 the Board of Directors, implemented by senior management and monitored by our risk management and internal audit 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

We construct and invest in energy infrastructure projects, purchase and sell commodities, issue short-term 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 and the value of the financial instruments we hold. We assess contracts used to manage market risk to determine whether all, or a portion, meet the definition of a derivative.

Derivative contracts we use to assist in managing our 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 exposure to commodity price risk in our non-regulated businesses:

- in our power generation business, we manage our exposure to fluctuating commodity prices through long-term contracts and hedging activities including selling and purchasing power 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
- in our liquids marketing business, we enter into pipeline and storage terminal capacity contracts. We fix a portion of our exposure on these contracts by entering into derivative instruments to manage our variable price fluctuations that arise from physical liquids transactions.

Our exposure to electricity price risk has been greatly reduced following the sales of our U.S. Northeast power generation assets in 2017 and our U.S. Northeast power retail contracts on March 1, 2018 as well as the continued wind-down of our remaining U.S. Power marketing contracts.

Interest rate risk

We utilize short-term 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 our commercial paper programs and amounts drawn on our credit facilities. A small portion of our long-term debt is at floating interest rates. In addition, we are exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. We manage our interest rate risk using a combination of interest rate swaps and option derivatives.

Foreign exchange risk

We generate revenues and incur expenses that are denominated in currencies other than Canadian dollars. As a result, our earnings and cash flows are exposed to currency fluctuations.

A portion of our businesses generate earnings in U.S. dollars, but 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 net income. As our 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 hedged on a rolling one-year basis using foreign exchange derivatives, but the exposure remains beyond that period.

Average exchange rate – U.S. to Canadian dollars

The average exchange rate for one U.S. dollar converted into Canadian dollars was as follows:

2018	**1.30**
2017	1.30
2016	1.33

The impact of changes in the value of the U.S. dollar on our U.S. operations is partially offset by interest on U.S. dollar-denominated debt, as set out in the table below. Comparable EBIT is a non-GAAP measure. See our Reconciliation of non-GAAP measures section for more information.

Significant U.S. dollar-denominated amounts

year ended December 31 (millions of US$)	**2018**	**2017**	**2016**
U.S. Natural Gas Pipelines comparable EBIT	**1,830**	1,360	947
Mexico Natural Gas Pipelines comparable EBIT[1]	**486**	353	215
U.S. Liquids Pipelines comparable EBIT	**876**	604	482
U.S. Power comparable EBIT[2]	**—**	100	285
Interest on U.S. dollar-denominated long-term debt and junior subordinated notes	**(1,325)**	(1,269)	(1,127)
Capitalized interest on U.S. dollar-denominated capital expenditures	**15**	3	22
U.S. dollar-denominated allowance for funds used during construction	**326**	259	181
U.S. comparable non-controlling interests and other	**(264)**	(195)	(195)
	1,944	1,215 —	810

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

2 Effective January 1, 2018, U.S. Power is no longer included in comparable EBIT.

Net investment hedges

We hedge our net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency swaps and foreign exchange options.

Counterparty credit risk

Our maximum counterparty credit exposure with respect to financial instruments at December 31,2018, without taking into account security held, consisted of cash and cash equivalents, accounts receivable, available-for-sale assets, derivative assets and a loan receivable.

We have exposure to counterparty credit risk in the following areas:

- cash and cash equivalents
- accounts receivable
- available-for-sale assets
- the fair value of derivative assets
- a loan receivable.

If a counterparty fails to meet its financial obligations to us according to the terms and conditions of the financial instrument, we could experience a financial loss.

We manage our exposure to this potential loss by dealing with creditworthy counterparties, obtaining financial assurances such as guarantees, letters of credit or cash where considered necessary, and setting limits on the amount we can transact with any one counterparty. There is no guarantee that these techniques will protect us from material losses.

We monitor counterparties and review our accounts receivable regularly. We record allowances for doubtful accounts using the specific identification method. At December 31, 2018 and 2017, we had no significant credit losses, no significant credit risk concentration 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 by continuously forecasting our cash flow and making sure we have adequate cash balances, cash flow 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, 2018, 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, 2018, 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, 2018, the internal control over financial reporting was effective.

Our internal control over financial reporting as ofDecember 31, 2018 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included in this document.

CEO and CFO certifications

Our President and CEO and our CFO have attested to the quality of the public disclosure in our fiscal 2018 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 certain 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 assumptionsbased on factors that are either subjective or highly uncertainwhen 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 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, we consider it to be impaired.

In 2018, the following impairments were recorded:

- a $722 million pre-tax impairment of the carrying value of our investment in Bison ($140 million after-tax and net of non-controlling interests)
- a $79 million pre-tax impairment of the carrying value of Tuscarora's goodwill ($15 million after-tax and net of non-controlling interests).

In 2017, the following impairments were recorded:

- a $954 million after-tax charge on the carrying value of our investment in Energy East and related projects
- a $16 million after-tax charge on the remaining carrying value of certain Energy turbine equipment
- a $12 million after-tax charge related to the remaining carrying value of our investment in TransGas.

Long-lived assets

Bison

At December 31, 2018, we evaluated our investment in the Bison natural gas pipeline for impairment in connection with the termination of certain customer transportation agreements. With the loss of these contracted future cash flows, and the persistence of unfavourable market conditions which have inhibited system flows on the pipeline, we determined that the asset’s remaining carrying value was no longer recoverable and recognized a non-cash impairment charge of $722 million in the U.S. Natural Gas Pipelines segment. Our share of the impairment charge, after-tax and net of non-controlling interests, was $140 million.

Energy East and related projects

In September 2017, we requested the NEB suspend the review of the Energy East and Eastern Mainline project applications for 30 days to provide time for us to conduct a careful review of the NEB's changes, announced on August 23, 2017, regarding the list of issues and environmental assessment factors related to the projects and how these changes impact the projects' costs, schedules and viability.

In October 2017, after careful review of the changed circumstances, we informed the NEB that we would not be proceeding with the Energy East and Eastern Mainline project applications. We also notified Québec’s Ministère du Developpement durable, de l’Environnement, et de la Lutte contre les changements climatiques that we were withdrawing the Energy East project from the environmental review process. As the Energy East pipeline was also to provide transportation services for the Upland pipeline, the U.S. Department of State was notified in October 2017 that we would no longer be pursuing the U.S. Presidential Permit application for that project.

We reviewed the approximate $1.3 billion carrying value of the projects, including AFUDC capitalized since inception, and recorded a $954 million after-tax non-cash charge in fourth quarter 2017. We ceased capitalizing AFUDC on the projects effective August 23, 2017, being the date of the NEB's announced scope changes. With Energy East's inability to reach a regulatory decision, no recoveries of costs from third parties are forthcoming.

Energy Turbine Equipment

At December 31, 2017, we recognized a non-cash impairment charge of $16 million after tax related to the carrying value of certain turbine equipment after determining that it was no longer recoverable. This turbine equipment was previously purchased for a power development project that did not proceed.

TransGas

In third quarter 2017, we recognized an impairment charge of $12 million after tax on our 46.5 per cent equity investment in TransGas.

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 elect to first assess qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired, and 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 perform a quantitative goodwill impairment test. We can also elect to proceed directly to the quantitative goodwill impairment test for any reporting unit. When a 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 including its goodwill exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value.

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.

Tuscarora

In fourth quarter 2018, Tuscarora finalized its regulatory filing in response to the 2018 FERC Actions resulting in a reduction in its recourse rates and, in January 2019, reached a settlement-in-principle with its customers. As a result of these developments, as well as changes to other valuation assumptions responsive to Tuscarora's commercial environment, we determined that the fair value of Tuscarora did not exceed its carrying value, including goodwill, and recorded a goodwill impairment charge of $79 million within the U.S. Natural Gas Pipelines segment. Our share of the goodwill impairment charge, after-tax and net of non-controlling interests, was $15 million. Our share of the remaining goodwill balance related to Tuscarora, net of non-controlling interests, was US$6 million at December 31, 2018 (2017 – US$21 million).

Great Lakes

At December 31, 2018, the estimated fair value of Great Lakes' natural gas transportation business exceeded its carrying value by less than 10 per cent. The fair value of this reporting unit was measured using a discounted cash flow analysis in its most recent valuation. Assumptions used in the analysis regarding Great Lakes' ability to realize long-term value in the North American energy market included the impact of its Form 501-G election, revenue opportunities on the system as well as changes to other valuation assumptions responsive to Great Lakes' commercial environment. Although evolving market conditions and other factors relevant to Great Lakes' long term financial performance have been positive, there is a risk that reductions in future cash flow forecasts or adverse changes in other key assumptions could result in a future impairment of a portion of the goodwill balance relating to Great Lakes. Our share of the goodwill related to Great Lakes, net of non-controlling interests, was US$378 million at December 31, 2018 (2017 – US$379 million).

Ravenswood

As a result of information received during the process to monetize the Company's U.S. Northeast power business in third quarter 2016, it was determined that the fair value of Ravenswood did not exceed its carrying value, including goodwill. The fair value of the reporting unit was determined using a combination of methods including a discounted cash flow analysis and a range of expected consideration from a potential sale. The expected cash flows were discounted using a risk-adjusted discount rate to determine the fair value. As a result, in 2016, we recorded a goodwill impairment charge on the full carrying value of Ravenswood goodwill of $1,085 million ($656 million after tax) within the Energy segment.

FINANCIAL INSTRUMENTS

Non-derivative financial instruments

Fair value of non-derivative financial instruments

Available-for-sale assets are recorded at fair value which is calculated using quoted market prices where available. Certain non-derivative financial instruments including cash and cash equivalents, accounts receivable, intangible and other assets, notes payable, accounts payable and other, 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 and would be classified in Level II of the fair value hierarchy.

Credit risk has been taken into consideration when calculating the fair value of non-derivative financial instruments.

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 pipelines 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, can 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.

Fair value of derivative instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses market rates and applies a discounted cash flow valuation model. The fair value of commodity derivatives has been calculated using a market approach which bases the fair value on a comparable transaction using quoted market prices, or in the absence of quoted market prices, third-party broker quotes or other valuation techniques. 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.

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 $)	**2018**	**2017**
Other current assets	**737**	332
Intangible and other assets	**61**	73
Accounts payable and other	**(922)**	(387)
Other long-term liabilities	**(42)**	(72)
	(166)	(54)

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, 2018 (millions of $)	Total fair value	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Derivative instruments held for trading					
Assets	767	717	50	—	—
Liabilities	(838)	(810)	(23)	—	(5)
Derivative instruments in hedging relationships					
Assets	31	20	8	2	1
Liabilities	(126)	(112)	(4)	(2)	(8)
	(166)	(185)	31	—	(12)

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 $)	2018	2017	2016
Derivative instruments held for trading[1]			
Amount of unrealized gains/(losses) in the year			
Commodities[2]	**28**	62	123
Foreign exchange	**(248)**	88	25
Interest rate	**—**	(1)	—
Amount of realized gains/(losses) in the year			
Commodities	**351**	(107)	(204)
Foreign exchange	**(24)**	18	62
Interest rate	**—**	1	—
Derivative instruments in hedging relationships			
Amount of realized (losses)/gains in the year			
Commodities	**(1)**	23	(167)
Foreign exchange	**—**	5	(101)
Interest rate	**(1)**	1	4

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 interest rate and foreign exchange held-for-trading derivative instruments are included on a net basis in interest expense and interest income and other, respectively.

2 In 2018 and 2017, 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 (2016 – net loss of $42 million).

Effect of fair value and cash flow hedging relationships

The following table details amounts presented on the Consolidated statement of income in which the effects of fair value or cash flow hedging relationships are recorded.

year ended December 31	Revenues (Energy)			Interest Expense		
(millions of $)	2018	2017	2016	2018	2017	2016
Total Amount Presented in the Condensed Consolidated Statement of Income	**2,124**	3,593	4,206	**(2,265)**	(2,069)	(1,998)
Fair Value Hedges						
Interest rate contracts						
Hedged items	**—**	—	—	**(71)**	(74)	(74)
Derivatives designated as hedging instruments	**—**	—	—	**(4)**	1	8
Cash Flow Hedges						
Reclassification of gains/(losses) on derivative instruments from AOCI to net income[1]						
Interest rate contracts	**—**	—	—	**22**	17	14
Commodity contracts	**5**	(20)	57	**—**	—	—

1 There are no amounts recognized in earnings that were excluded from effectiveness testing. Refer to the notes to our Consolidated financial statements.

Credit-risk-related contingent features of derivative instruments

Derivatives often contain financial assurance provisions that may require us to provide collateral if a credit risk-related contingent event occurs (for example, if our credit rating is downgraded to non-investment grade). We may also need to provide collateral if the fair value of our derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at December 31, 2018, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $6 million (2017 – $2 million), with no collateral provided in the normal course of business at December 31, 2018 and 2017. If the credit-risk-related contingent features in these agreements were triggered on December 31, 2018, we would have been required to provide collateral of $6 million (2017 – $2 million) to our counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

We have sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

ACCOUNTING CHANGES

Changes in accounting policies for 2018

Revenue from contracts with customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. The new guidance requires that an entity recognize revenue from these contracts in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in amounts that reflect the total consideration to which it expects to be entitled during the term of the contract in exchange for those promised goods or services. Goods or services that are promised to a customer are referred to as our "performance obligations". The total consideration to which we expect to be entitled can include fixed and variable amounts. We have variable revenue that is subject to factors outside of our influence, such as market prices, actions of third parties and weather conditions. We consider this variable revenue to be "constrained" as it cannot be reliably estimated, and therefore recognize variable revenue when the service is provided.

The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue recognition and related cash flows.

Our accounting policies related to revenue recognition have not substantially changed as a result of adopting the new guidance on revenue from contracts with customers. Results reported for 2018 reflect the application of the new guidance, while the 2017 and 2016 comparative results were prepared and reported under previous revenue recognition guidance which is referred to herein as "legacy U.S. GAAP". Under legacy U.S. GAAP, revenues were recognized when the risk, rewards, and benefits were transferred to the customer by the Company providing the goods or services under the contract, in an amount the Company expected to collect from the customer.

Under the new guidance applied in 2018, revenues are recognized when we satisfy our performance obligations by transferring control of the promised goods or services to our customers, in an amount that reflects the consideration we expect to be entitled to in exchange for those goods or services. We have elected to utilize a practical expedient to recognize revenues from our U.S. and certain Mexico natural gas pipelines contracts as customers are invoiced. The new guidance was effective January 1, 2018, was applied using the modified retrospective transition method, and did not result in any material differences in the amount and timing of revenue recognition.

Financial instruments

In January 2016, the FASB issued new guidance on the accounting for equity investments and financial liabilities. The new guidance changes the income statement effect of equity investments and the recognition of changes in the fair value of financial liabilities when the fair value option is elected. The new guidance also requires us to assess valuation allowances for deferred tax assets related to available for sale debt securities in combination with our other deferred tax assets. This new guidance was effective January 1, 2018 and did not have a material impact on our consolidated financial statements.

Income taxes

In October 2016, the FASB issued new guidance on the income tax effects of intra-entity transfers of assets other than inventory. The new guidance requires the recognition of deferred and current income taxes for intra-entity asset transfers when the transfer occurs. The new guidance was effective January 1, 2018, was applied using a modified retrospective approach, and resulted in an adjustment to retained earnings of $95 million

In February 2018, the FASB issued new guidance that allows a reclassification from AOCI to retained earnings for stranded tax effects resulting from U.S. Tax Reform. This guidance can be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change is recognized. This new guidance is effective January 1, 2019, however, early adoption is permitted. The Company elected to early adopt this guidance effective fourth quarter 2018 and used a portfolio approach for releasing the income tax effects from AOCI to retained earnings. The Company applied this guidance retrospectively, at the beginning of the period of adoption, resulting in an adjustment to retained earnings of $17 million.

Restricted cash
In November 2016, the FASB issued new guidance on restricted cash and cash equivalents on the statement of cash flows. The new guidance requires that the statement of cash flows explain the change during the period in the total cash and cash equivalents balance, and amounts generally described as restricted cash or restricted cash equivalents. Restricted cash and cash equivalents will be included with cash and cash equivalents when reconciling the beginning of period and end of period total amounts on the statement of cash flows. This new guidance was effective January 1, 2018, was applied retrospectively, and did not have an impact on our consolidated financial statements.

Employee post-retirement benefits
In March 2017, the FASB issued new guidance that requires entities to disaggregate the current service cost component from the other components of net benefit cost and present it with other current compensation costs for related employees in the income statement. The new guidance also requires that the other components of net benefit cost be presented elsewhere in the income statement and excluded from income from operations if such a subtotal is presented. In addition, the new guidance makes changes to the components of net benefit cost that are eligible for capitalization. Entities must use a retrospective transition method to adopt the requirement for separate presentation in the income statement of the components of net benefit cost, and a prospective transition method to adopt the change to capitalization of benefit costs. This new guidance was effective January 1, 2018 and did not have a material impact on our consolidated financial statements.

Hedge accounting
In August 2017, the FASB issued new guidance making more financial and non-financial hedging strategies eligible for hedge accounting. The new guidance also amends the presentation requirements relating to the change in fair value of a derivative and requires additional disclosures including cumulative basis adjustments for fair value hedges and the effect of hedging on individual line items in the statement of income. This new guidance is effective January 1, 2019 with early adoption permitted. This new guidance, which we elected to adopt effective January 1, 2018, was applied prospectively and did not have a material impact on our consolidated financial statements.

Derecognition of Nonfinancial Assets
In February 2017, the FASB issued new guidance that clarifies the scope provisions of nonfinancial assets and how to allocate consideration to each distinct asset. The FASB also amended the guidance for derecognition of a distinct nonfinancial asset in partial sale transactions. This new guidance was effective January 1, 2018, was applied using the modified retrospective transition method and did not have a material impact on our consolidated financial statements.

Goodwill impairment
In January 2017, the FASB issued new guidance on simplifying the test for goodwill impairment by eliminating Step 2 of the impairment test, which is the requirement to calculate the implied fair value of goodwill to measure the impairment charge. Instead, entities will record an impairment charge based on the excess of a reporting unit’s carrying amount over its fair value. This new guidance is effective January 1, 2020 with early adoption permitted. We elected to adopt this guidance effective fourth quarter 2018 as it simplified goodwill impairment testing. The guidance was applied prospectively and used in the 2018 annual goodwill impairment test.

Future accounting changes

Leases
In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessee is required to have both (1) the right to obtain substantially all of the economic benefits from the use of the asset and (2) the right to direct the use of the asset. The new guidance also establishes a right-of-use (ROU) model that requires a lessee to recognize a ROU asset and corresponding lease liability on the balance sheet for all leases with a term longer than 12 months. Lessees will classify leases as finance or operating, with classification affecting the pattern of expense recognition in the statement of income. The new guidance does not make extensive changes to lessor accounting. We currently expect that substantially all of our leases where we are the lessor will continue to be classified as operating leases under the new standard.

In January 2018, the FASB issued an optional practical expedient, to be applied upon transition, to omit the evaluation of land easements not previously accounted for as leases that existed or expired prior to the entity's adoption of the new lease guidance. An entity that elects this practical expedient is required to apply it consistently to all of its existing or expired land easements not previously accounted for as leases. We will apply this practical expedient upon transition to the new standard.

The new guidance is effective January 1, 2019, with early adoption permitted. We will adopt the new standard on its effective date. A modified retrospective transition approach is required, applying the new standard to all leases existing at the date of initial application being January 1, 2019. In July 2018, the FASB issued a transition option allowing entities to not apply the new guidance, including disclosure requirements, to the comparative periods they present in their financial statements in the year of adoption. We will apply this transition option and use the effective date as the date of initial application. Consequently, financial information will not be updated and disclosures required under the new standard will not be provided for dates and periods before January 1, 2019.

We will elect the package of practical expedients which permits entities not to reassess prior conclusions about lease identification, lease classification and initial direct costs under the rules of the new standard.

We believe that the most significant effects of adoption will relate to the recognition of new ROU assets and lease liabilities on our balance sheet for our operating leases and providing significant new disclosures about our leasing activities. The guidance will not impact our income statement. On adoption, we will recognize ROU assets of approximately $606 million and additional operating lease liabilities of approximately $600 million based on the present value of the remaining minimum lease payments for existing operating leases. The new standard also provides practical expedients for ongoing accounting. We will elect the short-term lease recognition exemption for all eligible leases. This means, for those leases that qualify, we will not recognize ROU assets or lease liabilities. We will also elect the practical expedient to not separate lease and non-lease components for all leases for which we are the lessee and for facility and liquids tank terminals for which we are the lessor.

Measurement of credit losses on financial instruments
In June 2016, the FASB issued new guidance that significantly changes how entities measure credit losses for most financial assets and certain other financial instruments that are not measured at fair value through net income. The new guidance amends the impairment model of financial instruments basing it on expected losses rather than incurred losses. These expected credit losses will be recognized as an allowance rather than as a direct write down of the amortized cost basis. The new guidance is effective January 1, 2020 and will be applied using a modified retrospective approach. We are currently evaluating the impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Fair value measurement
In August 2018, the FASB issued new guidance that amends certain disclosure requirements for fair value measurements. This new guidance is effective January 1, 2020, however, early adoption of certain or all requirements is permitted. We are currently evaluating the timing and impact of adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Defined benefit plans
In August 2018, the FASB issued new guidance which amends and clarifies disclosure requirements related to DB pension and other post retirement benefit plans. This new guidance is effective January 1, 2021, and will be applied on a retrospective basis, however early adoption is permitted. We are currently evaluating the timing and impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Implementation costs of cloud computing arrangements
In August 2018, the FASB issued new guidance requiring an entity in a hosting arrangement that is a service contract to follow the guidance for internal-use software to determine which implementation costs should be capitalized as an asset and which costs should be expensed. The guidance also requires the entity to amortize the capitalized implementation costs of a hosting arrangement over the term of the arrangement. This guidance is effective January 1, 2020, however, early adoption is permitted. This guidance can be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. We are currently evaluating the timing and impact of adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Consolidation
In October 2018, the FASB issued new guidance for determining whether fees paid to decision makers and service providers are variable interests for indirect interests held through related parties under common control. This new guidance is effective January 1, 2020, and will be applied on a retrospective basis, however early adoption is permitted. We are currently evaluating the timing and impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

RECONCILIATION OF COMPARABLE EBITDA AND COMPARABLE EBIT TO SEGMENTED EARNINGS

year ended December 31 (millions of $, except per share amounts)	2018	2017	2016
Comparable EBITDA			
Canadian Natural Gas Pipelines	**2,379**	2,144	2,182
U.S. Natural Gas Pipelines	**3,035**	2,357	1,682
Mexico Natural Gas Pipelines	**607**	519	332
Liquids Pipelines	**1,849**	1,348	1,152
Energy	**752**	1,030	1,281
Corporate	**(59)**	(21)	18
Comparable EBITDA	**8,563**	7,377	6,647
Depreciation and amortization	**(2,350)**	(2,048)	(1,939)
Comparable EBIT	**6,213**	5,329	4,708
Specific items:			
Bison asset impairment	**(722)**	—	—
Tuscarora goodwill impairment	**(79)**	—	—
U.S. Northeast power marketing contracts	**(5)**	—	—
Gain on sale of Cartier Wind power facilities	**170**	—	—
Bison contract terminations	**130**	—	—
Foreign exchange gain – inter-affiliate loan	**5**	63	—
Energy East impairment charge	**—**	(1,256)	—
Integration and acquisition related costs – Columbia	**—**	(91)	(179)
Keystone XL asset costs	**—**	(34)	(52)
Net gain/(loss) on sales of U.S. Northeast power generation assets	**—**	484	(844)
Gain on sale of Ontario solar assets	**—**	127	—
Ravenswood goodwill impairment	**—**	—	(1,085)
Alberta PPA terminations and settlement	**—**	—	(332)
Restructuring costs	**—**	—	(22)
TC Offshore loss on sale	**—**	—	(4)
Risk management activities[1]	**52**	62	123
Segmented earnings	**5,764**	4,684	2,313

1

year ended December 31 (millions of $)	2018	2017	2016
Canadian Power	**3**	11	4
U.S. Power	**(11)**	39	113
Liquids marketing	**71**	—	(2)
Natural Gas Storage	**(11)**	12	8
Total unrealized gains from risk management activities	**52**	62	123

QUARTERLY RESULTS

Selected quarterly consolidated financial data

(millions of $, except per share amounts)

2018	Fourth	Third	Second	First
Revenues	**3,904**	**3,156**	**3,195**	**3,424**
Net income attributable to common shares	**1,092**	**928**	**785**	**734**
Comparable earnings	**946**	**902**	**768**	**864**
Share statistics:				
Net income per common share – basic and diluted	**$1.19**	**$1.02**	**$0.88**	**$0.83**
Comparable earnings per common share	**$1.03**	**$1.00**	**$0.86**	**$0.98**
Dividends declared per common share	**$0.69**	**$0.69**	**$0.69**	**$0.69**

2017	Fourth	Third	Second	First
Revenues	3,617	3,195	3,230	3,407
Net income attributable to common shares	861	612	881	643
Comparable earnings	719	614	659	698
Share statistics:				
Net income per common share – basic and diluted	$0.98	$0.70	$1.01	$0.74
Comparable earnings per common share	$0.82	$0.70	$0.76	$0.81
Dividends declared per common share	$0.625	$0.625	$0.625	$0.625

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

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

In Liquids Pipelines, annual revenues and net income are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income are affected by:

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

In Energy, quarter-over-quarter revenues and net income are affected by:

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

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 certain 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.

In fourth quarter 2018, comparable earnings also excluded:

- a $143 million after-tax gain related to the sale of our interests in the Cartier Wind power facilities
- a $115 million deferred income tax recovery from an MLP regulatory liability write-off resulting from the 2018 FERC Actions
- a $52 million recovery of deferred income taxes as a result of finalizing the impact of U.S. Tax Reform
- a $27 million income tax recovery related to the sale of our U.S. Northeast power generation assets
- $25 million of after-tax income recognized on the Bison contract terminations
- a $140 million after-tax impairment charge on Bison
- a $15 million after-tax goodwill impairment charge on Tuscarora
- an after-tax net loss of $7 million related to our U.S. Northeast power marketing contracts.

In third quarter 2018, comparable earnings also excluded:

- after-tax income of $8 million related to our U.S. Northeast power marketing contracts.

In second quarter 2018, comparable earnings also excluded:

- an after-tax loss of $11 million related to our U.S. Northeast power marketing contracts.

In first quarter 2018, comparable earnings also excluded:

- an after-tax gain of $6 million related to our U.S. Northeast power marketing contracts, primarily due to income recognized on the sale of our retail contracts.

In fourth quarter 2017, comparable earnings excluded:

- an $804 million recovery of deferred income taxes as a result of U.S. Tax Reform
- a $136 million after-tax gain related to the sale of our Ontario solar assets
- a $64 million net after-tax gain related to the monetization of our U.S. Northeast power generation assets
- a $954 million after-tax impairment charge for the Energy East pipeline and related projects as a result of our decision not to proceed with the project applications
- a $9 million after-tax charge related to the maintenance and liquidation of Keystone XL assets.

In third quarter 2017, comparable earnings excluded:

- an incremental net loss of $12 million after tax related to the monetization of our U.S. Northeast power generation assets
- an after-tax charge of $30 million for integration-related costs associated with the acquisition of Columbia
- an after-tax charge of $8 million related to the maintenance of Keystone XL assets.

In second quarter 2017, comparable earnings excluded:

- a $265 million net after-tax gain related to the monetization of our U.S. Northeast power generation assets which included a $441 million after-tax gain on the sale of TC Hydro and a loss of $176 million after tax on the sale of the thermal and wind package
- an after-tax charge of $15 million for integration-related costs associated with the acquisition of Columbia
- an after-tax charge of $4 million related to the maintenance of Keystone XL assets.

In first quarter 2017, comparable earnings excluded:

- a charge of $24 million after tax for integration-related costs associated with the acquisition of Columbia
- a charge of $10 million after tax for costs related to the monetization of our U.S. Northeast power generation assets
- a charge of $7 million after tax related to the maintenance of Keystone XL assets

- a $7 million income tax recovery related to the realized loss on a third party sale of Keystone XL project assets.

FOURTH QUARTER 2018 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	2018	2017
Canadian Natural Gas Pipelines	**450**	333
U.S. Natural Gas Pipelines	**(34)**	461
Mexico Natural Gas Pipelines	**128**	93
Liquids Pipelines	**532**	(932)
Energy	**315**	472
Corporate	**23**	63
Total segmented earnings	**1,414**	490
Interest expense	**(603)**	(541)
Allowance for funds used during construction	**161**	140
Interest income and other	**(215)**	(9)
Income before income taxes	**757**	80
Income tax (expense)/recovery	**(38)**	870
Net income	**719**	950
Net loss/(income) attributable to non-controlling interests	**414**	(49)
Net income attributable to controlling interests	**1,133**	901
Preferred share dividends	**41**	40
Net income attributable to common shares	**1,092**	861
Net income per common share – basic and diluted	**$1.19**	$0.98

Net income attributable to common shares increased by $231 million or $0.21 per common share for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to the changes in net income described below, as well as the dilutive impact of common shares issued in 2017 and 2018 under our DRP and Corporate ATM program.

Fourth quarter 2018 results included:

- a $143 million after-tax gain related to the sale of our interests in the Cartier Wind power facilities
- a $115 million deferred income tax recovery from an MLP regulatory liability write-off resulting from the 2018 FERC Actions
- a $52 million recovery of deferred income taxes as a result of finalizing the impact of U.S. Tax Reform
- a $27 million income tax recovery related to the sale of our U.S. Northeast power generation assets
- $25 million of after-tax income recognized on the Bison contract terminations
- a $140 million after-tax impairment charge on Bison
- a $15 million after-tax goodwill impairment charge on Tuscarora
- an after-tax net loss of $7 million related to our U.S. Northeast power marketing contracts.

Fourth quarter 2017 results included:

- an $804 million recovery of deferred income taxes as a result of U.S. Tax Reform
- a $136 million after-tax gain related to the sale of our Ontario solar assets
- a $64 million net after-tax gain related to the monetization of our U.S. Northeast power generation assets
- a $954 million after-tax impairment charge for the Energy East pipeline and related projects as a result of our decision not to proceed with the project applications
- a $9 million after-tax charge related to the maintenance and liquidation of Keystone XL assets.

Net income in both 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.

Reconciliation of net income to comparable earnings

three months ended December 31 (millions of $, except per share amounts)	2018	2017
Net income attributable to common shares	**1,092**	861
Specific items (net of tax):		
Gain on sale of Cartier Wind power facilities	**(143)**	—
MLP regulatory liability write-off	**(115)**	—
U.S. Tax Reform	**(52)**	(804)
Net gain on sales of U.S. Northeast power generation assets	**(27)**	(64)
Bison contract terminations	**(25)**	—
Bison asset impairment	**140**	—
Tuscarora goodwill impairment	**15**	—
U.S. Northeast power marketing contracts	**7**	—
Gain on sale of Ontario solar assets	**—**	(136)
Energy East impairment charge	**—**	954
Keystone XL asset costs	**—**	9
Risk management activities[1]	**54**	(101)
Comparable earnings	**946**	719
Net income per common share	**$1.19**	$0.98
Specific items (net of tax):		
Gain on sale of Cartier Wind power facilities	**(0.16)**	—
MLP regulatory liability write-off	**(0.13)**	—
U.S. Tax Reform	**(0.06)**	(0.92)
Net gain on sales of U.S. Northeast power generation assets	**(0.03)**	(0.08)
Bison contract terminations	**(0.03)**	—
Bison asset impairment	**0.16**	—
Tuscarora goodwill impairment	**0.02**	—
U.S. Northeast power marketing contracts	**0.01**	—
Gain on sale of Ontario solar assets	**—**	(0.16)
Energy East impairment charge	**—**	1.09
Keystone XL asset costs	**—**	0.01
Risk management activities[1]	**0.06**	(0.10)
Comparable earnings per common share	**$1.03**	$0.82

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three months ended December 31 (millions of $)	2018	2017
Liquids marketing	**81**	15
Canadian Power	**—**	6
U.S. Power	**20**	136
Natural Gas Storage	**(5)**	7
Foreign exchange	**(169)**	(1)
Income tax attributable to risk management activities	**19**	(62)
Total unrealized (losses)/gains from risk management activities	**(54)**	101

Comparable EBITDA to comparable earnings

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

	three months ended December 31	
(millions of $)	**2018**	**2017**
Comparable EBITDA	**2,453**	1,903
Adjustments:		
Depreciation and amortization	**(681)**	(516)
Interest expense included in comparable earnings	**(603)**	(541)
Allowance for funds used during construction	**161**	140
Interest income and other included in comparable earnings	**11**	56
Income tax expense included in comparable earnings	**(268)**	(234)
Net income attributable to non-controlling interests included in comparable earnings	**(86)**	(49)
Preferred share dividends	**(41)**	(40)
Comparable earnings	**946**	719

Comparable EBITDA and comparable earnings – 2018 versus 2017

Comparable EBITDA increased by $550 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to the net effect of the following:

- higher contribution from Canadian Natural Gas Pipelines primarily due to the recovery of increased depreciation as a result of higher rates approved in both the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as higher flow-through taxes and incentive earnings
- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes, and amortization of net regulatory liabilities recognized as a result of U.S. Tax Reform
- higher contribution from Liquids Pipelines primarily due to higher volumes on the Keystone Pipeline System, increased earnings from liquids marketing activities and earnings from intra-Alberta pipelines placed in service in the second half of 2017
- higher revenues from Mexico Natural Gas Pipelines as a result of changes in timing of revenue recognition
- lower earnings from Bruce Power primarily due to lower volumes resulting from higher outage days.

Comparable earnings increased by $227 million or $0.21 per common share for the three months ended December 31, 2018 compared to the same period in 2017 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher depreciation primarily in Canadian Natural Gas Pipelines due to increased depreciation rates approved in the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement (these amounts are fully recovered as reflected in the increase in comparable EBITDA described above, having no net impact on comparable earnings) as well as higher depreciation related to new projects placed in service in 2017 and 2018
- higher interest expense primarily as a result of long-term debt and junior subordinated notes issuances, net of maturities
- lower interest income and other as a result of realized losses in 2018 compared to realized gains in 2017 on derivatives used to manage net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Comparable earnings per common share for the three months ended December 31, 2018 also reflect the dilutive impact of common shares issued in 2017 and 2018 under our DRP and our Corporate ATM program.

Highlights by business segment

Canadian Natural Gas Pipelines

Canadian Natural Gas Pipelines segmented earnings increased by $117 million for the three months ended December 31, 2018 compared to the same period in 2017 and are equivalent to comparable EBIT.

Net income for the NGTL System increased by $18 million for the three months ended December 31, 2018 compared to the same period in 2017 mainly due to a higher average investment base as a result of continued system expansions and higher OM&A incentive earnings.

Net income for the Canadian Mainline increased by $11 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to higher incentive earnings as a result of recording the full year impact of the Canadian Mainline 2018-2020 toll review upon receipt of the Mainline NEB 2018 Decision.

Comparable EBITDA increased by $249 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to the recovery of increased depreciation as a result of higher rates approved in both the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as higher flow-through taxes and incentive earnings. The full year impact of higher depreciation, flow-through taxes and incentive earnings as a result of the Canadian Mainline NEB 2018 Decision was reflected in fourth quarter 2018.

Depreciation and amortization increased by $132 million for the three months ended December 31, 2018 compared to the same period in 2017 mainly due to the increase in depreciation rates approved in the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as NGTL System facilities that were placed in service in 2018.

U.S. Natural Gas Pipelines

U.S. Natural Gas Pipelines segmented earnings decreased by $495 million for the three months ended December 31, 2018 compared to the same period in 2017.

Segmented earnings for the three months ended December 31, 2018 included:

- a $722 million non-cash asset impairment charge related to Bison
- a $79 million non-cash goodwill impairment charge related to Tuscarora
- $130 million of termination payments received on two of Bison's transportation contracts which was recorded in Revenues.

The amounts for each of these specified items are pre-tax and before reduction for the 74.5 per cent non-controlling interests in TC PipeLines, LP and have been excluded from our calculation of comparable EBIT. A stronger U.S. dollar in fourth quarter 2018 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2017.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$138 million for the three months ended December 31, 2018 compared to the same period in 2017 and was primarily the net effect of:

- increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service and additional contract sales on ANR and Great Lakes
- increased earnings due to the amortization of the net regulatory liabilities recognized in 2017, partially offset by a reduction in certain rates on Columbia Gas, as a result of U.S. Tax Reform.

Depreciation and amortization increased by US$18 million for the three months ended December 31, 2018 compared to the same period in 2017 mainly due to new projects placed in service.

Mexico Natural Gas Pipelines

Mexico Natural Gas Pipelines segmented earnings increased by $35 million for the three months ended December 31, 2018 compared to the same period in 2017 and are equivalent to comparable EBIT.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$24 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to:

- higher revenues from operations as a result of changes in timing of revenue recognition
- equity earnings from our investment in the Sur de Texas pipeline which records AFUDC during construction, net of interest expense on an inter-affiliate loan from TransCanada. The interest expense on this inter-affiliate loan is fully offset in Interest income and other in the Corporate segment
- incremental earnings from a CRE tariff increase.

Depreciation and amortization remained largely consistent for the three months ended December 31, 2018 compared to the same period in 2017.

Liquids Pipelines

Liquids Pipelines segmented earnings increased by $1,464 million for the three months ended December 31, 2018 compared to the same period in 2017 and included the following specific items:

- a $1,256 million pre-tax impairment charge in 2017 for the Energy East pipeline and related projects
- $11 million of pre-tax costs in 2017 related to Keystone XL for the maintenance and liquidation of project assets which were expensed pending further advancement of the project
- unrealized gains from changes in the fair value of derivatives related to our liquids marketing business.

Comparable EBITDA for Liquids Pipelines increased by $137 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to:

- higher contracted and uncontracted volumes on the Keystone Pipeline System
- higher contribution from liquids marketing activities from improved margins and volumes
- incremental contributions from intra-Alberta pipelines, Grand Rapids and Northern Courier, which began operations in the second half of 2017
- lower business development costs as a result of capitalizing Keystone XL expenditures in 2018
- a stronger U.S. dollar which had a positive impact on the Canadian dollar equivalent earnings from our U.S. operations.

Depreciation and amortization increased by $6 million for the three months ended December 31, 2018 compared to the same period in 2017 as a result of new facilities being placed in service and the effect of a stronger U.S. dollar.

Energy

Energy segmented earnings were $157 million lower in the three months ended December 31, 2018 compared to the same period in 2017 and included the following specific items:

- a pre-tax gain in 2018 of $170 million related to the sale of our interests in the Cartier Wind power facilities
- a pre-tax net loss of $10 million related to our U.S. Northeast power marketing contracts. These results have been excluded from Energy's comparable earnings in 2018 as we do not consider the wind-down of the remaining contracts part of our underlying operations. The contract portfolio is scheduled to run-off through to mid-2020
- a pre-tax gain in 2017 of $127 million related to the sale of our Ontario solar assets
- a pre-tax net gain of $15 million in 2017 related to the monetization of our U.S. Northeast power generation assets
- 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 Energy decreased by $47 million for the three months ended December 31, 2018 compared to the same period in 2017 mainly due to the net effect of:

- decreased earnings from Bruce Power primarily due to lower volumes resulting from higher outage days
- decreased Western and Eastern Power results due to the sales of our Cartier Wind power facilities in October 2018 and our Ontario solar assets in December 2017, partially offset by higher Western Power realized margins on higher generation volumes
- lower Natural Gas Storage results primarily due to pipeline constraints in the Alberta natural gas market which limited our ability to access our storage facilities and resulted in lower realized natural gas storage price spreads.

Depreciation and amortization decreased by $6 million for the three months ended December 31, 2018 compared to the same period on 2017 primarily due to the cessation of depreciation on our Cartier Wind power facilities upon classification as held for sale at June 30, 2018.

Corporate

Corporate segmented earnings decreased by $40 million for the three months ended December 31, 2018 compared to the same period in 2017 and included the following specific items:

- foreign exchange gains on a peso-denominated inter-affiliate loan to the Sur de Texas project for our proportionate share of the project's financing. There is a corresponding foreign exchange loss included in Interest income and other on the inter-affiliate loan receivable which fully offsets this gain.

Comparable EBITDA decreased by $33 million for the three months ended December 31, 2018 compared to the same period in 2017, primarily due to increased general and administrative costs.

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
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 plan
Empress	A major delivery/receipt point for natural gas near the Alberta/Saskatchewan border
FID	Final investment decision
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it
GHG	Greenhouse gas
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
LTAA	Long Term Adjustment Account
MLP	Master limited partnership
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
TOMS	TransCanada Operational Management System
TSA	Transportation Service Agreement
WCSB	Western Canada Sedimentary Basin

Accounting terms

AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive (loss)/income
FASB	Financial Accounting Standards Board (U.S.)
GAAP	U.S. generally accepted accounting principles
RRA	Rate-regulated accounting
ROE	Return on common equity

Government and regulatory bodies terms

AER	Alberta Energy Regulator
CCIR	Carbon Competitiveness Incentive Regulation
CEPA	Canadian Energy Pipeline Association
CFE	Comisión Federal de Electricidad (Mexico)
CGA	Canadian Gas Association
CRE	Comisión Reguladora de Energia, or Energy Regulatory Commission (Mexico)
DOJ	U.S. Department of Justice
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
OBPS	Output Based Pricing System
OPEC	Organization of the Petroleum Exporting Countries
OPG	Ontario Power Generation
PHMSA	Pipeline and Hazardous Materials Safety Administration
SEC	U.S. Securities and Exchange Commission
SDDENR	South Dakota Department of Environment and Natural Resources
SGER	Specified Gas Emitters Regulations (replaced by the CCIR)
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 TransCanada Corporation (TransCanada 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 2018 to that in 2017, and highlights significant changes between 2017 and 2016. 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, 2018, 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.



Russell K. Girling
President and
Chief Executive Officer



Donald R. Marchand
Executive Vice-President and
Chief Financial Officer

February 13, 2019

Report of Independent Registered Public Accounting Firm

To the Shareholders of TransCanada Corporation

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of TransCanada Corporation (the Company) as of December 31, 2018, and 2017, 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, 2018, 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, 2018, and 2017, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2018, 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, 2018, based on the criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 13, 2019 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.



Chartered Professional Accountants

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

Calgary, Canada
February 13, 2019

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of TransCanada Corporation

Opinion on Internal Control over Financial Reporting

We have audited TransCanada Corporation's (the Company) internal control over financial reporting as of December 31, 2018, based on the 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, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also 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, 2018 and 2017, 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, 2018, and the related notes (collectively, the consolidated financial statements), and our report dated February 13, 2019 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. 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 disposition 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 13, 2019

Consolidated statement of income

year ended December 31 (millions of Canadian $, except per share amounts)	2018	2017	2016
Revenues (Note 5)			
Canadian Natural Gas Pipelines	**4,038**	3,693	3,682
U.S. Natural Gas Pipelines	**4,314**	3,584	2,526
Mexico Natural Gas Pipelines	**619**	570	378
Liquids Pipelines	**2,584**	2,009	1,755
Energy	**2,124**	3,593	4,206
	13,679	13,449	12,547
Income from Equity Investments (Note 9)	**714**	773	514
Operating and Other Expenses			
Plant operating costs and other	**3,591**	3,906	3,861
Commodity purchases resold	**1,488**	2,382	2,172
Property taxes	**569**	569	555
Depreciation and amortization	**2,350**	2,055	1,939
Goodwill and other asset impairment charges (Notes 8, 11 and 12)	**801**	1,257	1,388
	8,799	10,169	9,915
Gain/(Loss) on Assets Held for Sale/Sold (Note 26)	**170**	631	(833)
Financial Charges			
Interest expense (Note 17)	**2,265**	2,069	1,998
Allowance for funds used during construction	**(526)**	(507)	(419)
Interest income and other	**76**	(184)	(103)
	1,815	1,378	1,476
Income before Income Taxes	**3,949**	3,306	837
Income Tax Expense/(Recovery) (Note 16)			
Current	**315**	149	156
Deferred	**284**	566	196
Deferred – U.S. Tax Reform and 2018 FERC Actions	**(167)**	(804)	—
	432	(89)	352
Net Income	**3,517**	3,395	485
Net (loss)/income attributable to non-controlling interests (Note 19)	**(185)**	238	252
Net Income Attributable to Controlling Interests	**3,702**	3,157	233
Preferred share dividends	**163**	160	109
Net Income Attributable to Common Shares	**3,539**	2,997	124
Net Income per Common Share (Note 20)			
Basic	**$3.92**	$3.44	$0.16
Diluted	**$3.92**	$3.43	$0.16
Dividends Declared per Common Share	**$2.76**	$2.50	$2.26
Weighted Average Number of Common Shares (millions) (Note 20)			
Basic	**902**	872	759
Diluted	**903**	874	760

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 $)	2018	2017	2016
Net Income	**3,517**	3,395	485
Other Comprehensive Income/(Loss), Net of Income Taxes			
Foreign currency translation gains and losses on net investment in foreign operations	**1,358**	(749)	3
Reclassification of foreign currency translation gains on disposal of foreign operations	**—**	(77)	—
Change in fair value of net investment hedges	**(42)**	—	(10)
Change in fair value of cash flow hedges	**(10)**	3	30
Reclassification to net income of gains and losses on cash flow hedges	**21**	(2)	42
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**(114)**	(11)	(26)
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**15**	16	16
Other comprehensive income/(loss) on equity investments	**86**	(106)	(87)
Other comprehensive income/(loss) (Note 22)	**1,314**	(926)	(32)
Comprehensive Income	**4,831**	2,469	453
Comprehensive (loss)/income attributable to non-controlling interests	**(13)**	83	241
Comprehensive Income Attributable to Controlling Interests	**4,844**	2,386	212
Preferred share dividends	**163**	160	109
Comprehensive Income Attributable to Common Shares	**4,681**	2,226	103

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 $)	2018	2017	2016
Cash Generated from Operations			
Net income	**3,517**	3,395	485
Depreciation and amortization	**2,350**	2,055	1,939
Goodwill and other asset impairment charges (Notes 8, 11 and 12)	**801**	1,257	1,388
Deferred income taxes (Note 16)	**284**	566	196
Deferred income taxes – U.S. Tax Reform and 2018 FERC Actions (Note 16)	**(167)**	(804)	—
Income from equity investments (Note 9)	**(714)**	(773)	(514)
Distributions received from operating activities of equity investments (Note 9)	**985**	970	844
Employee post-retirement benefits funding, net of expense (Note 23)	**(35)**	(64)	(3)
(Gain)/loss on assets held for sale/sold (Note 26)	**(170)**	(631)	833
Equity allowance for funds used during construction	**(374)**	(362)	(253)
Unrealized losses/(gains) on financial instruments	**220**	(149)	(149)
Other	**(40)**	43	55
(Increase)/decrease in operating working capital (Note 25)	**(102)**	(273)	248
Net cash provided by operations	**6,555**	5,230	5,069
Investing Activities			
Capital expenditures (Note 4)	**(9,418)**	(7,383)	(5,007)
Capital projects in development (Note 4)	**(496)**	(146)	(295)
Contributions to equity investments (Notes 4 and 9)	**(1,015)**	(1,681)	(765)
Acquisitions, net of cash acquired	**—**	—	(13,608)
Proceeds from sales of assets, net of transaction costs	**614**	4,683	6
Reimbursement of costs related to capital projects in development (Note 12)	**470**	634	—
Other distributions from equity investments (Note 9)	**121**	362	727
Deferred amounts and other	**(295)**	(168)	159
Net cash used in investing activities	**(10,019)**	(3,699)	(18,783)
Financing Activities			
Notes payable issued/(repaid), net	**817**	1,038	(329)
Long-term debt issued, net of issue costs	**6,238**	3,643	12,333
Long-term debt repaid	**(3,550)**	(7,085)	(7,153)
Junior subordinated notes issued, net of issue costs	**—**	3,468	1,549
Dividends on common shares	**(1,571)**	(1,339)	(1,436)
Dividends on preferred shares	**(158)**	(155)	(100)
Distributions to non-controlling interests	**(225)**	(283)	(279)
Common shares issued, net of issue costs	**1,148**	274	7,747
Common shares repurchased (Note 20)	**—**	—	(14)
Preferred shares issued, net of issue costs	**—**	—	1,474
Partnership units of TC PipeLines, LP issued, net of issue costs	**49**	225	215
Common units of Columbia Pipeline Partners LP acquired	**—**	(1,205)	—
Net cash provided by/(used in) financing activities	**2,748**	(1,419)	14,007
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**73**	(39)	(127)
(Decrease)/Increase in Cash and Cash Equivalents	**(643)**	73	166
Cash and Cash Equivalents			
Beginning of year	**1,089**	1,016	850
Cash and Cash Equivalents			
End of year	**446**	1,089	1,016

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

Consolidated balance sheet

at December 31 (millions of Canadian $)		2018	2017
ASSETS			
Current Assets			
Cash and cash equivalents		**446**	1,089
Accounts receivable		**2,535**	2,522
Inventories		**431**	378
Assets held for sale (Note 6)		**543**	—
Other (Note 7)		**1,180**	691
		5,135	4,680
Plant, Property and Equipment (Note 8)		**66,503**	57,277
Equity Investments (Note 9)		**7,113**	6,366
Regulatory Assets (Note 10)		**1,548**	1,376
Goodwill (Note 11)		**14,178**	13,084
Loan Receivable from Affiliate (Note 9)		**1,315**	919
Intangible and Other Assets (Note 12)		**1,921**	1,484
Restricted Investments		**1,207**	915
		98,920	86,101
LIABILITIES			
Current Liabilities			
Notes payable (Note 13)		**2,762**	1,763
Accounts payable and other (Note 14)		**5,408**	4,057
Dividends payable		**668**	586
Accrued interest		**646**	605
Current portion of long-term debt (Note 17)		**3,462**	2,866
		12,946	9,877
Regulatory Liabilities (Note 10)		**3,930**	4,321
Other Long-Term Liabilities (Note 15)		**1,008**	727
Deferred Income Tax Liabilities (Note 16)		**6,026**	5,403
Long-Term Debt (Note 17)		**36,509**	31,875
Junior Subordinated Notes (Note 18)		**7,508**	7,007
		67,927	59,210
EQUITY			
Common shares, no par value (Note 20)		**23,174**	21,167
Issued and outstanding:	December 31, 2018 – 918 million shares December 31, 2017 – 881 million shares		
Preferred shares (Note 21)		**3,980**	3,980
Additional paid-in capital		**17**	—
Retained earnings		**2,773**	1,623
Accumulated other comprehensive loss (Note 22)		**(606)**	(1,731)
Controlling Interests		**29,338**	25,039
Non-controlling interests (Note 19)		**1,655**	1,852
		30,993	26,891
		98,920	86,101

Commitments, Contingencies and Guarantees (Note 27)
Corporate Restructuring Costs (Note 28)
Variable Interest Entities (Note 29)

The accompanying Notes to the consolidated financial statements are an integral part of these statements.
On behalf of the Board:



Russell K. Girling, Director



John E. Lowe, Director

Consolidated statement of equity

year ended December 31 (millions of Canadian $)	2018	2017	2016
Common Shares (Note 20)			
Balance at beginning of year	**21,167**	20,099	12,102
Shares issued:			
Under at-the-market equity issuance program, net of issue costs	**1,118**	216	—
Under dividend reinvestment and share purchase plan	**855**	790	177
On exercise of stock options	**34**	62	74
Under public offerings, net of issue costs	**—**	—	7,752
Shares repurchased	**—**	—	(6)
Balance at end of year	**23,174**	21,167	20,099
Preferred Shares			
Balance at beginning of year	**3,980**	3,980	2,499
Shares issued under public offerings, net of issue costs	**—**	—	1,481
Balance at end of year	**3,980**	3,980	3,980
Additional Paid-In Capital			
Balance at beginning of year	**—**	—	7
Issuance of stock options, net of exercises	**10**	6	6
Dilution from TC PipeLines, LP units issued	**7**	26	24
Asset drop-downs to TC PipeLines, LP	**—**	(202)	(38)
Columbia Pipeline Partners LP acquisition	**—**	(171)	—
Common shares repurchased (Note 20)	**—**	—	(8)
Reclassification of additional paid-in capital deficit to retained earnings	**—**	341	9
Balance at end of year	**17**	—	—
Retained Earnings			
Balance at beginning of year	**1,623**	1,138	2,769
Net income attributable to controlling interests	**3,702**	3,157	233
Common share dividends	**(2,501)**	(2,184)	(1,733)
Preferred share dividends	**(163)**	(159)	(122)
Adjustment related to income tax effects of asset drop-downs to TC PipeLines, LP (Note 3)	**95**	—	—
Reclassification of AOCI to retained earnings resulting from U.S. Tax Reform (Note 3)	**17**	—	—
Adjustment related to employee share-based payments	**—**	12	—
Reclassification of additional paid-in capital deficit to retained earnings	**—**	(341)	(9)
Balance at end of year	**2,773**	1,623	1,138
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(1,731)**	(960)	(939)
Other comprehensive income/(loss) attributable to controlling interests (Note 22)	**1,142**	(771)	(21)
Reclassification of AOCI to retained earnings resulting from U.S. Tax Reform (Note 3)	**(17)**	—	—
Balance at end of year	**(606)**	(1,731)	(960)
Equity Attributable to Controlling Interests	**29,338**	25,039	24,257
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,852**	1,726	1,717
Net (loss)/income attributable to non-controlling interests	**(185)**	238	252
Other comprehensive income/(loss) attributable to non-controlling interests	**172**	(155)	(11)
Issuance of TC PipeLines, LP units			
Proceeds, net of issue costs	**49**	225	215
Decrease in TransCanada's ownership of TC PipeLines, LP	**(9)**	(41)	(40)
Distributions declared to non-controlling interests	**(224)**	(280)	(279)
Reclassification from/(to) common units subject to rescission or redemption (Note 19)	**—**	106	(1,179)
Impact of Columbia Pipeline Partners LP acquisition	**—**	33	—
Acquisition of non-controlling interests in Columbia Pipeline Partners LP	**—**	—	1,051
Balance at end of year	**1,655**	1,852	1,726
Total Equity	**30,993**	26,891	25,983

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

Notes to consolidated financial statements

1. DESCRIPTION OF TRANSCANADA'S BUSINESS

TransCanada Corporation (TransCanada 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 Energy, each of which offers different products and 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 consists of the Company's investments in 40,686 km (25,281 miles) of regulated natural gas pipelines.

U.S. Natural Gas Pipelines

The U.S. Natural Gas Pipelines segment consists of the Company's investments in 50,199 km (31,192 miles) of regulated natural gas pipelines, 535 Bcf of regulated natural gas storage facilities, midstream and other assets.

Mexico Natural Gas Pipelines

The Mexico Natural Gas Pipelines segment consists of the Company's investments in 1,670 km (1,038 miles) of regulated natural gas pipelines.

Liquids Pipelines

The Liquids Pipelines segment consists of the Company's investments in 4,874 km (3,030 miles) of crude oil pipeline systems which connect Alberta and U.S. crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas.

Energy

The Energy segment primarily consists of the Company's investments in 10 power generation facilities and 118 Bcf of non-regulated natural gas storage facilities. These include assets in Alberta, Ontario, Québec, New Brunswick and Arizona. At December 31, 2018, the Coolidge generating station is classified as Assets held for sale. Refer to Note 6, Assets held for sale, for further information.

2. ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with U.S. generally accepted accounting principles (GAAP). Amounts are stated in Canadian dollars unless otherwise indicated.

Basis of Presentation

These consolidated financial statements include the accounts of TransCanada 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. TransCanada 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. TransCanada records its proportionate share of undivided interests in certain assets. Certain prior year amounts have been reclassified to conform to current year presentation.

Use of Estimates and Judgments

In preparing these consolidated financial statements, TransCanada 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. Some of the estimates and judgments the Company has to make have a material impact on the consolidated financial statements, but they do not involve significant subjectivity or uncertainty. Others also have a material impact but the assumptions underlying these accounting estimates also relate to matters that are highly uncertain at the time the estimate or judgment is made or are subjective.

Significant estimates and judgments used in the preparation of the consolidated financial statements that involve assumptions that are highly uncertain or subjective include, but are not limited to:

- fair value of plant, property and equipment and equity investments (Notes 8 and 9)
- fair value of goodwill (Note 11)
- fair value of intangible assets (Note 12) and
- fair value of assets and liabilities acquired in a business combination (Note 26).

Significant estimates and judgments used in the preparation of the consolidated financial statements that are provided by an independent expert or do not involve assumptions that are highly uncertain or subjective include, but are not limited to:

- depreciation rates of plant, property and equipment (Note 8)
- carrying value of regulatory assets and liabilities (Note 10)
- carrying value of asset retirement obligations (Note 15)
- provisions for income taxes, including U.S. Tax Reform (Note 16)
- assumptions used to measure retirement and other post-retirement obligations (Note 23)
- fair value of financial instruments (Note 24) and
- provisions for commitments, contingencies, guarantees (Note 27) and restructuring costs (Note 28).

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 National Energy Board (NEB), the Alberta Energy Regulator (AER) or the B.C. Oil and Gas Commission (OGC). 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 TransCanada's rate-regulated businesses which may differ from that otherwise recognized in non-rate-regulated businesses to appropriately 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 asset 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.

TransCanada's businesses that apply RRA currently include Canadian, U.S. and Mexico natural gas pipelines, 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. Once in operation, the Coastal GasLink pipeline is not expected to apply RRA.

Revenue Recognition

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 are subject to regulatory decisions by the NEB. 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 NEB. The Company's Canadian natural gas pipelines are generally not subject to risks related to variances in revenues and most costs. These variances are generally subject to deferral treatment and are recovered or refunded in future tolls. Revenues recognized prior to an NEB decision on rates for that period reflect the NEB's last approved return on equity (ROE) assumptions. Adjustments to revenues are recorded when the NEB decision is received. Canadian natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

U.S. Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's U.S. natural gas pipelines are generated from contractual arrangements for committed capacity and from the transportation of natural gas. Revenues earned from firm contracted capacity arrangements are generally recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed.

The Company's U.S. 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 regards 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.

Revenues from the Company's midstream natural gas services, including gathering, treating, conditioning, processing, compression and liquids handling services, are generated from contractual arrangements and are recognized ratably over the term of the contract. The Company also 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. Midstream natural gas service revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas for which it provides midstream services.

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.

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.

Energy

Power Generation

Revenues from the Company's Energy 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 earned from the sale of proprietary natural gas are recognized in the month of delivery. 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, crude oil in transit and 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 twelve 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. 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 one 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.

Regulated natural gas storage base gas, which is valued at cost, represents gas volumes that are maintained to ensure adequate reservoir pressure exists to deliver natural gas held in storage. Base gas is not depreciated.

When 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. Costs incurred to remove plant, property and equipment from service, net of any salvage proceeds, are also recorded in accumulated depreciation.

Midstream and Other

Plant, property and equipment for midstream assets is carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Gathering and processing facilities are depreciated at annual rates ranging from
1.7 per cent to 2.5 per cent, and other plant and equipment are depreciated at various rates. 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.

The Company participates as a working interest partner in the development of certain Marcellus and Utica acreage. The working interest allows the Company to invest in drilling activities in addition to receiving a royalty interest in well production. The Company uses the successful efforts method of accounting for natural gas and crude oil resulting from its portion of drilling activities. Capitalized well costs are depleted based on the units of production method.

Liquids Pipelines
Plant, property and equipment for liquids pipelines is carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and pumping equipment are depreciated at annual rates ranging from two per cent to 2.5 per cent, and other plant and equipment are depreciated at various rates. 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.

Energy
Plant, property and equipment for Energy 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. 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.

Non-regulated 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 three per cent to 20 per cent.

Capitalized Project Costs
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 Intangible and other 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.

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 that are estimated 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 and 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 the 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 including its goodwill exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit’s carrying value exceeds its fair value.

Loans and Receivables

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

Power Purchase Arrangements

A power purchase arrangement (PPA) is a long-term contract for the purchase or sale of power on a predetermined basis. TransCanada has PPAs for the sale of power that are accounted for as operating leases where TransCanada is the lessor. During 2016, the Company terminated its Alberta PPAs under which it purchased power and recorded an impairment charge. Prior to their termination, substantially all of these PPAs were also accounted for as operating leases, where TransCanada was the lessee, and initial payments to acquire these PPAs were recognized in Intangible and other assets and amortized on a straight-line basis over the term of the contracts. A portion of these PPAs was subleased to third parties under terms and conditions similar to the PPAs, and was also accounted for as operating leases with the margin earned from the subleases recorded in Revenues. Refer to Note 12, Intangible and other assets, for further information.

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 NEB's Land Matters Consultation Initiative (LMCI), TransCanada is required to collect funds to cover estimated future pipeline abandonment costs for all NEB 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 may only be used to fund the abandonment of the NEB 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 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.

Canadian income taxes are not provided 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 Operating and other expenses.

For those AROs that the Company records, the following assumptions are used:

- when the asset is expected to be retired
- the scope and cost of abandonment and reclamation activities that are required and
- appropriate inflation and discount rates.

The Company has recorded AROs related to its non-regulated natural gas storage operations, mineral rights and power generation facilities. The scope and timing of asset retirements related to most of the Company's natural gas pipelines and liquids pipelines is 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, with the exception of certain abandoned facilities and certain facilities expected to be retired as part of an ongoing modernization program that will improve system integrity and enhance service reliability and flexibility on its Columbia Gas pipeline.

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 expensed when they are utilized or cancelled/retired by government agencies. Compliance costs are expensed when incurred. Allowances granted to or internally generated by TransCanada are not attributed a value for accounting purposes. When required, TransCanada accrues emission liabilities on the Consolidated balance sheet upon the generation or sale of power using the best estimate of the amount required to settle the obligation. Allowances and credits not used for compliance are sold and any gain or loss is recorded in Revenues.

Stock Options and Other Compensation Programs

TransCanada'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. 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), a savings plan and other post-retirement benefit plans. Contributions made by the Company to the DC Plans and savings plan 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 of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service life 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 (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 (AOCI) and into net income over the expected average remaining service life 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 expected average remaining service life 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 of the 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 NEB.

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 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.

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.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipelines 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 refunded or recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as regulatory assets or regulatory liabilities and are refunded to or collected from ratepayers in subsequent years 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 for all costs 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 2018

Revenue from contracts with customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. The new guidance requires that an entity recognize revenue from these contracts in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in amounts that reflect the total consideration to which it expects to be entitled during the term of the contract in exchange for those promised goods or services. Goods or services that are promised to a customer are referred to as the Company's "performance obligations." The total consideration 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.

The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue recognition and related cash flows.

The Company's accounting policies related to revenue recognition have not substantially changed as a result of adopting the new guidance on revenue from contracts with customers. Results reported for 2018 reflect the application of the new guidance, while the 2017 and 2016 comparative results were prepared and reported under previous revenue recognition guidance which is referred to herein as "legacy U.S. GAAP." Under legacy U.S. GAAP, revenues were recognized when the risk, rewards, and benefits were transferred to the customer by the Company providing the goods or services under the contract, in an amount the Company expected to collect from the customer.

Under the new guidance applied in 2018, revenues are recognized when the Company satisfies its performance obligations by transferring control of the promised goods or services to its customers, in an amount that reflects the consideration the Company expects to be entitled to in exchange for those goods or services. The Company has elected to utilize a practical expedient to recognize revenues from its U.S. and certain Mexico natural gas pipelines contracts as customers are invoiced. The new guidance was effective January 1, 2018, was applied using the modified retrospective transition method, and did not result in any material differences in the amount and timing of revenue recognition. Refer to Note 5, Revenues, for further information related to the impact of adopting the new guidance.

Financial instruments

In January 2016, the FASB issued new guidance on the accounting for equity investments and financial liabilities. The new guidance changes the income statement effect of equity investments and the recognition of changes in the fair value of financial liabilities when the fair value option is elected. The new guidance also requires the Company to assess valuation allowances for deferred tax assets related to available for sale debt securities in combination with their other deferred tax assets. This new guidance was effective January 1, 2018 and did not have a material impact on the Company's consolidated financial statements.

Income taxes

In October 2016, the FASB issued new guidance on the income tax effects of intra-entity transfers of assets other than inventory. The new guidance requires the recognition of deferred and current income taxes for intra-entity asset transfers when the transfer occurs. The new guidance was effective January 1, 2018, was applied using a modified retrospective approach, and resulted in an adjustment to retained earnings of $95 million.

In February 2018, the FASB issued new guidance that allows a reclassification from AOCI to retained earnings for stranded tax effects resulting from U.S. Tax Reform. This guidance can be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change is recognized. This new guidance is effective January 1, 2019, however, early adoption is permitted. The Company elected to early adopt this guidance effective fourth quarter 2018 and used a portfolio approach for releasing the income tax effects from AOCI to retained earnings. The Company applied this guidance retrospectively, at the beginning of the period of adoption, resulting in an adjustment to retained earnings of $17 million.

Restricted cash
In November 2016, the FASB issued new guidance on restricted cash and cash equivalents on the statement of cash flows. The new guidance requires that the statement of cash flows explain the change during the period in the total cash and cash equivalents balance, and amounts generally described as restricted cash or restricted cash equivalents. Restricted cash and cash equivalents will be included with cash and cash equivalents when reconciling the beginning of period and end of period total amounts on the statement of cash flows. This new guidance was effective January 1, 2018, was applied retrospectively, and did not have an impact on the Company's consolidated financial statements.

Employee post-retirement benefits
In March 2017, the FASB issued new guidance that requires entities to disaggregate the current service cost component from the other components of net benefit cost and present it with other current compensation costs for related employees in the income statement. The new guidance also requires that the other components of net benefit cost be presented elsewhere in the income statement and excluded from income from operations if such a subtotal is presented. In addition, the new guidance makes changes to the components of net benefit cost that are eligible for capitalization. Entities must use a retrospective transition method to adopt the requirement for separate presentation in the income statement of the components of net benefit cost, and a prospective transition method to adopt the change to capitalization of benefit costs. This new guidance was effective January 1, 2018 and did not have a material impact on the Company's consolidated financial statements.

Hedge accounting
In August 2017, the FASB issued new guidance making more financial and non-financial hedging strategies eligible for hedge accounting. The new guidance also amends the presentation requirements relating to the change in fair value of a derivative and requires additional disclosures including cumulative basis adjustments for fair value hedges and the effect of hedging on individual line items in the statement of income. This new guidance is effective January 1, 2019 with early adoption permitted. This new guidance, which the Company elected to adopt effective January 1, 2018, was applied prospectively and did not have a material impact on the Company's consolidated financial statements.

Derecognition of Nonfinancial Assets
In February 2017, the FASB issued new guidance that clarifies the scope provisions of nonfinancial assets and how to allocate consideration to each distinct asset. The FASB also amended the guidance for derecognition of a distinct nonfinancial asset in partial sale transactions. This new guidance was effective January 1, 2018, was applied using the modified retrospective transition method and did not have a material impact on the Company's consolidated financial statements.

Goodwill impairment
In January 2017, the FASB issued new guidance on simplifying the test for goodwill impairment by eliminating Step 2 of the impairment test, which is the requirement to calculate the implied fair value of goodwill to measure the impairment charge. Instead, entities will record an impairment charge based on the excess of a reporting unit’s carrying amount over its fair value. This new guidance is effective January 1, 2020 with early adoption permitted. The Company elected to adopt this guidance effective fourth quarter 2018 as it simplified goodwill impairment testing. The guidance was applied prospectively and used in the 2018 annual goodwill impairment test.

Future Accounting Changes

Leases
In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessee is required to have both (1) the right to obtain substantially all of the economic benefits from the use of the asset and (2) the right to direct the use of the asset. The new guidance also establishes a right-of-use (ROU) model that requires a lessee to recognize a ROU asset and corresponding lease liability on the balance sheet for all leases with a term longer than 12 months. Lessees will classify leases as finance or operating, with classification affecting the pattern of expense recognition in the statement of income. The new guidance does not make extensive changes to lessor accounting. The Company currently expects that substantially all of its leases where the Company is the lessor will continue to be classified as operating leases under the new standard.

In January 2018, the FASB issued an optional practical expedient, to be applied upon transition, to omit the evaluation of land easements not previously accounted for as leases that existed or expired prior to the entity's adoption of the new lease guidance. An entity that elects this practical expedient is required to apply it consistently to all of its existing or expired land easements not previously accounted for as leases. The Company will apply this practical expedient upon transition to the new standard.

The new guidance is effective January 1, 2019, with early adoption permitted. The Company will adopt the new standard on its effective date. A modified retrospective transition approach is required, applying the new standard to all leases existing at the date of initial application being January 1, 2019. In July 2018, the FASB issued a transition option allowing entities to not apply the new guidance, including disclosure requirements, to the comparative periods they present in their financial statements in the year of adoption. The Company will apply this transition option and use the effective date as the date of initial application. Consequently, financial information will not be updated and disclosures required under the new standard will not be provided for dates and periods before January 1, 2019.

The Company will elect the package of practical expedients which permits entities not to reassess prior conclusions about lease identification, lease classification and initial direct costs under the rules of the new standard.

The Company believes that the most significant effects of adoption will relate to the recognition of new ROU assets and lease liabilities on the Company's balance sheet for its operating leases and providing significant new disclosures about the Company's leasing activities. The guidance will not impact the Company's income statement. On adoption, the Company will recognize ROU assets of approximately $606 million and additional operating lease liabilities of approximately $600 million based on the present value of the remaining minimum lease payments for existing operating leases. The new standard also provides practical expedients for a Company’s ongoing accounting. The Company will elect the short-term lease recognition exemption for all eligible leases. This means, for those leases that qualify, the Company will not recognize ROU assets or lease liabilities. The Company will also elect the practical expedient to not separate lease and non-lease components for all leases for which the Company is the lessee and for facility and liquids tank terminals for which the Company is the lessor.

Measurement of credit losses on financial instruments

In June 2016, the FASB issued new guidance that significantly changes how entities measure credit losses for most financial assets and certain other financial instruments that are not measured at fair value through net income. The new guidance amends the impairment model of financial instruments basing it on expected losses rather than incurred losses. These expected credit losses will be recognized as an allowance rather than as a direct write down of the amortized cost basis. The new guidance is effective January 1, 2020 and will be applied using a modified retrospective approach. 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.

Fair value measurement

In August 2018, the FASB issued new guidance that amends certain disclosure requirements for fair value measurements. This new guidance is effective January 1, 2020, however, early adoption of certain or all requirements is permitted. The Company is currently evaluating the timing and impact of adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

Defined benefit plans

In August 2018, the FASB issued new guidance which amends and clarifies disclosure requirements related to DB pension and other post retirement benefit plans. This new guidance is effective January 1, 2021, and will be applied on a retrospective basis, however early adoption is permitted. The Company is currently evaluating the timing and impact of the adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

Implementation costs of cloud computing arrangements

In August 2018, the FASB issued new guidance requiring an entity in a hosting arrangement that is a service contract to follow the guidance for internal-use software to determine which implementation costs should be capitalized as an asset and which costs should be expensed. The guidance also requires the entity to amortize the capitalized implementation costs of a hosting arrangement over the term of the arrangement. This guidance is effective January 1, 2020, however, early adoption is permitted. This guidance can be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. The Company is currently evaluating the timing and impact of adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

Consolidation

In October 2018, the FASB issued new guidance for determining whether fees paid to decision makers and service providers are variable interests for indirect interests held through related parties under common control. This new guidance is effective January 1, 2020, and will be applied on a retrospective basis, however early adoption is permitted. The Company is currently evaluating the timing and impact of the adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

4. SEGMENTED INFORMATION

year ended December 31, 2018 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate[1]	Total
Revenues	4,038	4,314	619	2,584	2,124	—	13,679
Intersegment revenues	—	162	—	—	56	(218) [2]	—
	4,038	4,476	619	2,584	2,180	(218)	13,679
Income from equity investments	12	256	22	64	355	5 [3]	714
Plant operating costs and other	(1,405)	(1,368)	(34)	(630)	(313)	159 [2]	(3,591)
Commodity purchases resold	—	—	—	—	(1,488)	—	(1,488)
Property taxes	(266)	(199)	—	(98)	(6)	—	(569)
Depreciation and amortization	(1,129)	(664)	(97)	(341)	(119)	—	(2,350)
Goodwill and other asset impairment charges	—	(801)	—	—	—	—	(801)
Gain on sale of assets	—	—	—	—	170	—	170
Segmented earnings/(losses)	1,250	1,700	510	1,579	779	(54)	5,764
Interest expense							(2,265)
Allowance for funds used during construction							526
Interest income and other[3]							(76)
Income before income taxes							3,949
Income tax expense							(432)
Net income							3,517
Net loss attributable to non-controlling interests							185
Net income attributable to controlling interests							3,702
Preferred share dividends							(163)
Net income attributable to common shares							3,539
Capital spending							
Capital expenditures	2,442	5,591	463	110	767	45	9,418
Capital projects in development	36	1	—	459	—	—	496
Contributions to equity investments	—	179	334	12	490	—	1,015
	2,478	5,771	797	581	1,257	45	10,929

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 foreign exchange gains on the Company's inter-affiliate loan with Sur de Texas. The offsetting foreign exchange losses on the inter-affiliate loan are included in Interest income and other. The peso-denominated loan to the Sur de Texas joint venture represents the Company's proportionate share of long-term debt financing for this joint venture. Refer to Note 9, Equity investments, for further information.

year ended December 31, 2017 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate[1]	Total
Revenues	3,693	3,584	570	2,009	3,593	—	13,449
Intersegment revenues	—	51	—	—	—	(51) [2]	—
	3,693	3,635	570	2,009	3,593	(51)	13,449
Income/(loss) from equity investments	11	240	(9)	(3)	471	63 [3]	773
Plant operating costs and other	(1,300)	(1,340)	(42)	(623)	(550)	(51) [2]	(3,906)
Commodity purchases resold	—	—	—	—	(2,382)	—	(2,382)
Property taxes	(260)	(181)	—	(89)	(39)	—	(569)
Depreciation and amortization	(908)	(594)	(93)	(309)	(151)	—	(2,055)
Goodwill and other asset impairment charges	—	—	—	(1,236)	(21)	—	(1,257)
Gain on sale of assets	—	—	—	—	631	—	631
Segmented earnings/(losses)	1,236	1,760	426	(251)	1,552	(39)	4,684
Interest expense							(2,069)
Allowance for funds used during construction							507
Interest income and other[3]							184
Income before income taxes							3,306
Income tax recovery							89
Net income							3,395
Net income attributable to non-controlling interests							(238)
Net income attributable to controlling interests							3,157
Preferred share dividends							(160)
Net income attributable to common shares							2,997
Capital spending							
Capital expenditures	2,106	3,712	833	341	350	41	7,383
Capital projects in development	75	—	—	71	—	—	146
Contributions to equity investments	—	118	1,121	117	325	—	1,681
	2,181	3,830	1,954	529	675	41	9,210

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 foreign exchange gains on the Company's inter-affiliate loan with Sur de Texas. The offsetting foreign exchange losses on the inter-affiliate loan are included in Interest income and other. The peso-denominated loan to the Sur de Texas joint venture represents the Company's proportionate share of long-term debt financing for this joint venture. Refer to Note 9, Equity investments, for further information.

year ended December 31, 2016 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate[1]	Total
Revenues	3,682	2,526	378	1,755	4,206	—	12,547
Intersegment revenues	—	56	—	—	—	(56) [2]	—
	3,682	2,582	378	1,755	4,206	(56)	12,547
Income/(loss) from equity investments	12	214	(3)	(1)	292	—	514
Plant operating costs and other	(1,245)	(1,057)	(43)	(568)	(884)	(64) [2]	(3,861)
Commodity purchases resold	—	—	—	—	(2,172)	—	(2,172)
Property taxes	(267)	(120)	—	(88)	(80)	—	(555)
Depreciation and amortization	(875)	(425)	(45)	(292)	(302)	—	(1,939)
Goodwill and other asset impairment charges	—	—	—	—	(1,388)	—	(1,388)
Loss on assets held for sale/sold	—	(4)	—	—	(829)	—	(833)
Segmented earnings/(losses)	1,307	1,190	287	806	(1,157)	(120)	2,313
Interest expense							(1,998)
Allowance for funds used during construction							419
Interest income and other							103
Income before income taxes							837
Income tax expense							(352)
Net income							485
Net income attributable to non-controlling interests							(252)
Net income attributable to controlling interests							233
Preferred share dividends							(109)
Net income attributable to common shares							124
Capital spending							
Capital expenditures	1,372	1,517	944	668	473	33	5,007
Capital projects in development	153	—	—	142	—	—	295
Contributions to equity investments	—	5	198	327	235	—	765
	1,525	1,522	1,142	1,137	708	33	6,067

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.

at December 31 (millions of Canadian $)	2018	2017
Total Assets by segment		
Canadian Natural Gas Pipelines	**18,407**	16,904
U.S. Natural Gas Pipelines	**44,115**	35,898
Mexico Natural Gas Pipelines	**7,058**	5,716
Liquids Pipelines	**17,352**	15,438
Energy	**8,475**	8,503
Corporate	**3,513**	3,642
	98,920	86,101

Geographic Information

year ended December 31 (millions of Canadian $)	2018	2017	2016
Revenues			
Canada – domestic	**4,187**	3,618	3,697
Canada – export	**1,075**	1,255	1,177
United States	**7,798**	8,006	7,295
Mexico	**619**	570	378
	13,679	13,449	12,547

at December 31 (millions of Canadian $)	2018	2017
Plant, Property and Equipment		
Canada	**23,226**	21,632
United States	**37,385**	30,693
Mexico	**5,892**	4,952
	66,503	57,277

5. REVENUES

On January 1, 2018, the Company adopted new FASB guidance on revenue from contracts with customers using the modified retrospective transition method for all contracts that were in effect on the date of adoption. Results reported for 2018 reflect the application of the new guidance, while the 2017 and 2016 comparative results were prepared and reported under previous revenue recognition guidance which is referred to herein as "legacy U.S. GAAP."

Disaggregation of Revenues

The following tables summarizes total Revenues for the year ended December 31, 2018.

(millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Energy	Total
Revenues from contracts with customers						
Capacity arrangements and transportation	**4,038**	**3,549**	**614**	**2,079**	**—**	**10,280**
Power generation	**—**	**—**	**—**	**—**	**1,771**	**1,771**
Natural gas storage and other	**—**	**654**	**5**	**3**	**81**	**743**
	4,038	**4,203**	**619**	**2,082**	**1,852**	**12,794**
Other revenues[1,2]	**—**	**111**	**—**	**502**	**272**	**885**
	4,038	**4,314**	**619**	**2,584**	**2,124**	**13,679**

1 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements within each operating segment. Income from lease arrangements includes certain long term PPAs, as well as certain liquids pipelines capacity and transportation arrangements. These arrangements are not in the scope of the new guidance, therefore, revenues related to these contracts are excluded from revenues from contracts with customers. Refer to Note 24, Risk management and financial instruments, for further information on income from financial instruments.

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 16, Income taxes, for further information.

Revenues from contracts with customers are recognized net of any 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.

Financial Statement Impact of Adopting Revenue from Contracts with Customers

The Company adopted the new guidance using the modified retrospective transition method.As a practical expedient under this transition method, the Company is not required to analyze completed contracts at the date of adoption. As a result of adopting the new guidance, the Company made the adjustments described below on January 1, 2018.

Capacity Arrangements and Transportation

For certain natural gas pipeline capacity contracts, amounts are invoiced to the customer in accordance with the terms of the contract, however, the related revenues are recognized when the Company satisfies its performance obligation to provide committed capacity ratably over the term of the contract. This difference in timing between revenue recognition and amounts invoiced creates a contract asset or contract liability under the new revenue recognition guidance. Under legacy U.S. GAAP, these differences were recorded as Accounts receivable. Under the new guidance, contract assets are included in Other current assets and Intangibles and other assets and contract liabilities are included in Accounts payable and other and Other long-term liabilities.

Impact of New Revenue Recognition Guidance on Date of Adoption

The following table illustrates the impact of the adoption of the new revenue recognition guidance on the Company's previously reported consolidated balance sheet line items:

(millions of Canadian $)	As reported December 31, 2017	Adjustment	January 1, 2018
Current Assets			
Accounts receivable	2,522	(62)	2,460
Other[1]	691	79	770
Current Liabilities			
Accounts payable and other[2]	4,057	17	4,074

1 Adjustment relates to contract assets previously included in Accounts receivable.
2 Adjustment relates to contract liabilities previously included in Accounts receivable.

Pro-forma Financial Statements under Legacy U.S. GAAP

As required by the new revenue recognition guidance, the following tables illustrate the pro-forma impact on the affected line items on the Consolidated balance sheet, as at December 31, 2018, using legacy U.S. GAAP:

	December 31, 2018	
(millions of Canadian $)	As reported	Pro-forma using legacy U.S. GAAP
Current Assets		
Accounts receivable	**2,535**	**2,694**
Other	**1,180**	**1,021**

Contract Balances

(millions of Canadian $)	December 31, 2018	January 1, 2018
Receivables from contracts with customers	**1,684**	1,736
Contract assets[1]	**159**	79
Long-term contract assets[2]	**21**	—
Contract liabilities[3]	**11**	17
Long-term contract liabilities[4]	**121**	—

1 Recorded as part of Other current assets on the Consolidated balance sheet.
2 Recorded as part of Intangibles and other assets on the Consolidated balance sheet.
3 Comprised of deferred revenue recorded in Accounts payable and other on the Consolidated balance sheet. During the year ended December 31, 2018, $17 million of revenue was recognized that was included in the contract liability at the beginning of the year.
4 Comprised of deferred revenue recorded in Other long-term liabilities on the Consolidated balance sheet.

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 required by the new revenue recognition guidance, the following provides disclosure on future revenues allocated to remaining performance obligations representing contracted revenues that have not yet been recognized. Certain contracts that qualify for the use of one of the following practical expedients are excluded from the future revenues disclosures:

1. The original expected duration of the contract is one year or less.
2. The Company recognizes revenue from the contract that is equal to the amount invoiced, where the amount invoiced represents the value to the customer of the service performed to date. This is referred to as the "right to invoice" practical expedient.
3. The variable revenue generated from the contract is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct good or service that forms part of a single performance obligation in a series. A single performance obligation in a series occurs when the promises under a contract are a series of distinct services that are substantially the same and have the same pattern of transfer to the customer over time.

The following provides a discussion of the transaction price allocated to future performance obligations as well as practical expedients used by the Company.

Capacity Arrangements and Transportation

As at December 31, 2018, future revenues from long-term pipeline capacity arrangements and transportation contracts extending through 2043 are approximately $30.1 billion, of which approximately $6.0 billion is expected to be recognized in 2019.

Future revenues from long-term capacity arrangements and transportation contracts do not include constrained variable revenues or arrangements to which the right to invoice practical expedient has been applied. As a result, these amounts are not representative of potential total future revenues expected from these contracts.

Future revenues from the Company's Canadian natural gas pipelines' regulated firm capacity contracts include fixed revenues for the time periods that tolls under current rate settlements are in effect, which is approximately one to three years. Many of these contracts are long-term in nature and revenues from the remaining performance obligations that extend beyond the current rate settlement term are considered to be fully constrained since future tolls remain unknown. Revenues from these contracts will be recognized once the performance obligation to provide capacity has been satisfied and the regulator has approved the applicable tolls. In addition, the Company considers interruptible transportation service revenues to be variable revenues since volumes cannot be estimated. These variable revenues are recognized on a monthly basis when the Company satisfies the performance obligation and have been excluded from the future revenues disclosure as the Company applies the practical expedient related to variable revenues to these contracts. The future variable revenues earned under these contracts are allocated entirely to unsatisfied performance obligations at December 31, 2018.

The Company also applies the right to invoice practical expedient to all of its U.S. and certain of its Mexico regulated natural gas pipeline capacity arrangements and flow-through revenues. Revenues from regulated capacity arrangements are recognized based on current rates and flow-through revenues are earned from the recovery of operating expenses. These revenues are recognized on a monthly basis as the Company performs the services and are excluded from future revenues disclosures.

Revenues from liquids pipelines capacity arrangements have a variable component based on volumes transported. As a result, these variable revenues are excluded from the future revenues disclosures as the Company applies the practical expedient related to variable revenues to these contracts. The future variable revenues earned under these contracts are allocated entirely to unsatisfied performance obligations at December 31, 2018.

Power Generation

The Company has long-term power generation contracts extending through 2030. Revenues from power generation have a variable component related to market prices that are subject to factors outside the Company’s influence. These revenues are considered to be fully constrained and are recognized on a monthly basis when the Company satisfies the performance obligation. The Company applies the practical expedient related to variable revenues to these contracts. As a result, future revenues from these contracts are excluded from the disclosures.

Natural Gas Storage and Other

As at December 31, 2018, future revenues from long-term natural gas storage and other contracts extending through 2033 are approximately $1.2 billion, of which approximately $283 million is expected to be recognized in 2019. The Company applies the practical expedients related to contracts that are for a duration of one year or less and where it recognizes variable consideration, and therefore excludes the related revenues from the future revenues disclosure. As a result, this amount is lower than the potential total future revenues from these contracts.

6. ASSETS HELD FOR SALE

Coolidge Generating Station

On December 14, 2018, TransCanada entered into an agreement to sell its Coolidge generating station in Arizona to SWG Coolidge Holdings, LLC for approximately US$465 million, subject to timing of the close and related adjustments. In January 2019, pursuant to the terms of the Coolidge PPA, Salt River Project Agriculture Improvement and Power District, the counterparty to this arrangement, exercised their right of first refusal on this sale.

The sale will result in an estimated gain of approximately $65 million ($50 million after tax) including the impact of an estimated $10 million of foreign currency translation gains. This gain will be recognized upon closing of the sale transaction, which is expected to occur mid-2019.

At December 31, 2018, the related assets and liabilities were classified as held for sale in the Energy segment as follows:

(millions of Canadian $)	
Assets held for sale	
Accounts receivable	**6**
Plant, property and equipment	**537**
Total assets held for sale	**543**
Liabilities related to assets held for sale	
Other long-term liabilities	**(3)**
Total liabilities related to assets held for sale[1]	**(3)**

1 Included in Accounts payable and other on the Consolidated balance sheet.

7. OTHER CURRENT ASSETS

at December 31 (millions of Canadian $)	2018	2017
Fair value of derivative contracts (Note 24)	**737**	332
Contract assets (Note 5)	**159**	—
Regulatory assets (Note 10)	**83**	23
Cash provided as collateral	**55**	99
Prepaid expenses	**41**	109
Other	**105**	128
	1,180	691

8. PLANT, PROPERTY AND EQUIPMENT

at December 31 (millions of Canadian $)	2018 Cost	2018 Accumulated Depreciation	2018 Net Book Value	2017 Cost	2017 Accumulated Depreciation	2017 Net Book Value
Canadian Natural Gas Pipelines						
NGTL System						
Pipeline	**10,764**	**4,500**	**6,264**	10,153	4,190	5,963
Compression	**3,289**	**1,677**	**1,612**	3,021	1,593	1,428
Metering and other	**1,247**	**613**	**634**	1,188	569	619
	15,300	**6,790**	**8,510**	14,362	6,352	8,010
Under construction	**2,111**	**—**	**2,111**	940	—	940
	17,411	**6,790**	**10,621**	15,302	6,352	8,950
Canadian Mainline						
Pipeline	**10,077**	**6,777**	**3,300**	9,763	6,455	3,308
Compression	**3,642**	**2,656**	**986**	3,605	2,499	1,106
Metering and other	**652**	**241**	**411**	655	207	448
	14,371	**9,674**	**4,697**	14,023	9,161	4,862
Under construction	**149**	**—**	**149**	156	—	156
	14,520	**9,674**	**4,846**	14,179	9,161	5,018
Other Canadian Natural Gas Pipelines[1]						
Other	**1,842**	**1,420**	**422**	1,815	1,363	452
Under construction	**124**	**—**	**124**	4	—	4
	1,966	**1,420**	**546**	1,819	1,363	456
	33,897	**17,884**	**16,013**	31,300	16,876	14,424
U.S. Natural Gas Pipelines						
Columbia Gas						
Pipeline	**6,711**	**251**	**6,460**	3,550	125	3,425
Compression	**2,932**	**132**	**2,800**	1,547	64	1,483
Metering and other	**2,884**	**75**	**2,809**	2,306	37	2,269
	12,527	**458**	**12,069**	7,403	226	7,177
Under construction	**4,347**	**—**	**4,347**	3,332	—	3,332
	16,874	**458**	**16,416**	10,735	226	10,509
ANR						
Pipeline	**1,600**	**443**	**1,157**	1,427	365	1,062
Compression	**1,978**	**388**	**1,590**	1,582	286	1,296
Metering and other	**1,217**	**324**	**893**	961	268	693
	4,795	**1,155**	**3,640**	3,970	919	3,051
Under construction	**272**	**—**	**272**	358	—	358
	5,067	**1,155**	**3,912**	4,328	919	3,409

at December 31 (millions of Canadian $)	2018 Cost	2018 Accumulated Depreciation	2018 Net Book Value	2017 Cost	2017 Accumulated Depreciation	2017 Net Book Value
Other U.S. Natural Gas Pipelines						
GTN	**2,322**	**951**	**1,371**	2,107	822	1,285
Great Lakes	**2,180**	**1,251**	**929**	1,988	1,113	875
Columbia Gulf	**1,753**	**74**	**1,679**	1,115	37	1,078
Midstream	**1,212**	**91**	**1,121**	1,085	54	1,031
Other[2]	**1,190**	**474**	**716**	1,950	574	1,376
	8,657	**2,841**	**5,816**	8,245	2,600	5,645
Under construction	**846**	**—**	**846**	699	—	699
	9,503	**2,841**	**6,662**	8,944	2,600	6,344
	31,444	**4,454**	**26,990**	24,007	3,745	20,262
Mexico Natural Gas Pipelines						
Pipeline	**3,172**	**301**	**2,871**	2,872	214	2,658
Compression	**506**	**41**	**465**	448	30	418
Metering and other	**640**	**91**	**549**	573	65	508
	4,318	**433**	**3,885**	3,893	309	3,584
Under construction	**1,990**	**—**	**1,990**	1,368	—	1,368
	6,308	**433**	**5,875**	5,261	309	4,952
Liquids Pipelines						
Keystone Pipeline System						
Pipeline	**9,780**	**1,271**	**8,509**	9,002	992	8,010
Pumping equipment	**1,065**	**184**	**881**	1,022	152	870
Tanks and other[3]	**3,598**	**488**	**3,110**	3,314	385	2,929
	14,443	**1,943**	**12,500**	13,338	1,529	11,809
Under construction[4]	**18**	**—**	**18**	456	—	456
	14,461	**1,943**	**12,518**	13,794	1,529	12,265
Intra-Alberta Pipelines[5]						
Pipeline	**762**	**22**	**740**	748	3	745
Pumping equipment	**104**	**3**	**101**	104	—	104
Tanks and other	**291**	**8**	**283**	259	1	258
	1,157	**33**	**1,124**	1,111	4	1,107
Under construction	**84**	**—**	**84**	47	—	47
	1,241	**33**	**1,208**	1,158	4	1,154
	15,702	**1,976**	**13,726**	14,952	1,533	13,419
Energy						
Natural Gas[6]	**2,062**	**708**	**1,354**	2,645	743	1,902
Wind[7]	**—**	**—**	**—**	673	204	469
Natural Gas Storage and Other	**741**	**169**	**572**	734	156	578
	2,803	**877**	**1,926**	4,052	1,103	2,949
Under construction	**1,735**	**—**	**1,735**	1,028	—	1,028
	4,538	**877**	**3,661**	5,080	1,103	3,977
Corporate	**448**	**210**	**238**	411	168	243
	92,337	**25,834**	**66,503**	81,011	23,734	57,277

1 Includes Foothills, Ventures LP, Great Lakes Canada and Coastal GasLink .

2 Includes Portland, North Baja, Tuscarora and Crossroads as well as Bison for 2017. Bison's remaining carrying value was fully impaired at December 31, 2018.

3 Includes tanks that are accounted for as operating leases. The cost and accumulated depreciation of these facilities were $ 194 million and $23 million, respectively, at December 31, 2018 (2017 – $ 184 million and $19 million, respectively), while revenues of $ 15 million were recognized in 2018 (2017 – $16 million; 2016 – $ 16 million).

4 Certain costs related to the Keystone XL project were recorded in Plant, property and equipment at December 31, 2017. In 2018, these costs were reclassified to Capital projects in development as the Company recommenced capitalizing Keystone XL development costs.

5 Includes Northern Courier and White Spruce. Northern Courier is accounted for as an operating lease and was placed in service on November 1, 2017. The cost and accumulated depreciation of this facility were $1,130 million and $32 million, respectively, at December 31, 2018 (2017 – $ 1,111 million and $4 million, respectively), while revenues of $ 142 million were recognized in 2018 (2017 – $ 20 million).

6 Includes Coolidge, Grandview, Bécancour, Halton Hills and the Alberta cogeneration natural gas-fired facilities. Coolidge, Grandview and Bécancour have long-term PPAs that are accounted for as operating leases. The cost and accumulated depreciation of these facilities were $655 million and $268 million, respectively, at December 31, 2018 (2017 – $1,264 million and $354 million, respectively). At December 31, 2018, the cost and accumulated depreciation of Coolidge were reclassified to Assets held for sale. Refer to Note 6, Assets held for sale, for further information. Revenues of $216 million were recognized in 2018 (2017 – $215 million; 2016 – $212 million) through the sale of electricity under the related PPAs for these assets.

7 The Company closed the sale of its Cartier Wind power assets on October 24, 2018. Refer to Note 26, Acquisitions and dispositions, for further information.

Bison Impairment

At December 31, 2018, the Company evaluated its investment in its Bison natural gas pipeline for impairment in connection with the termination of certain customer transportation agreements. The termination of these agreements released the Company from providing any future services. With the loss of these future cash flows and the persistence of unfavourable market conditions which have inhibited system flows on the pipeline, the Company determined that the asset’s remaining carrying value was no longer recoverable and recognized a non-cash impairment charge of $722 million pre-tax in its U.S. Natural Gas Pipelines segment. The non-cash charge was recorded in Goodwill and other asset impairment charges on the Consolidated statement of income. As Bison is a TC PipeLines, LP asset, in which the Company has a 25.5 per cent interest, the Company's share of the impairment charge, after tax and net of non-controlling interests, was $140 million.

The termination of the transportation agreements resulted in the receipt of$130 million in termination payments which were recorded in Revenues in 2018. The Company's share of this amount, after tax and net of non-controlling interests, was $25 million.

Energy East and Related Projects Impairment

On October 5, 2017, the Company informed the NEB that it will not proceed with the Energy East, Eastern Mainline and Upland projects. Based on this decision, the Company evaluated the carrying value of its Property, plant and equipment related to the Eastern Mainline project including AFUDC. Due to the inability to reach a regulatory decision for this project, there were no recoveries of costs from third parties. As a result, the Company recognized a non-cash impairment charge of $83 million ($64 million after tax) in the Liquids Pipelines segment. The non-cash charge was recorded in Goodwill and other asset impairment charges on the Consolidated statement of income.

Energy Turbine Impairment

At December 31, 2017, the Company recognized a non-cash impairment charge of$21 million ($16 million after tax) in the Energy segment related to the remaining carrying value of certain equipment after determining that it was no longer recoverable. This turbine equipment was previously purchased for a power development project that did not proceed. The non-cash charge was recorded in Goodwill and other asset impairment charges on the Consolidated statement of income.

9. EQUITY INVESTMENTS

(millions of Canadian $)	Ownership Interest at December 31, 2018	Income/(Loss) from Equity Investments year ended December 31 2018	2017	2016	Equity Investments at December 31 2018	2017
Canadian Natural Gas Pipelines						
TQM	50.0%	**12**	11	12	**71**	68
U.S. Natural Gas Pipelines						
Northern Border[1]	50.0%	**87**	87	92	**677**	641
Iroquois[2]	50.0%	**60**	59	54	**291**	280
Millennium[3]	47.5%	**75**	66	33	**511**	291
Pennant Midstream[3]	47.0%	**17**	11	6	**256**	228
Other	Various	**17**	17	29	**113**	92
Mexico Natural Gas Pipelines						
Sur de Texas[4]	60.0%	**27**	66	(3)	**627**	399
TransGas	nil	**—**	(12)	—	**—**	—
Liquids Pipelines						
Grand Rapids[5]	50.0%	**65**	17	(1)	**1,028**	996
Other[6]	Various	**(1)**	(20)	—	**21**	20
Energy						
Bruce Power[7]	48.3%	**311**	434	293	**3,166**	2,987
Portlands Energy[8]	50.0%	**36**	31	33	**289**	301
ASTC Power Partnership	50.0%	**—**	—	(37)	**—**	—
Other	Various	**8**	6	3	**63**	63
		714	773	514	**7,113**	6,366

1 At December 31, 2018, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Border Pipeline Company was US$115 million (2017 – US$115 million) due to the fair value assessment of assets at the time of acquisition.

2 At December 31, 2018, the difference between the carrying value of the investment and the underlying equity in the net assets of Iroquois was US$41 million (2017 – US$41 million) due mainly to the fair value assessment of the assets at the time of acquisition.

3 Acquired as part of Columbia Pipeline Group, Inc. (Columbia) on July 1, 2016. Income from Equity investments reflects equity earnings from the date of acquisition.

4 TransCanada has an ownership interest of 60.0 per cent in Sur de Texas which, as a jointly controlled entity, applies the equity method of accounting. Income from equity investments includes foreign exchange gains and losses recorded in the Corporate segment which are fully offset in Interest income and other in the Consolidated statement of income.

5 Grand Rapids was placed in service in August 2017. At December 31, 2018, the difference between the carrying value of the investment and the underlying equity in the net assets of Grand Rapids was $102 million (2017 – $105 million) due mainly to interest capitalized during construction and the fair value of guarantees.

6 Includes investments in Canaport Energy East Marine Terminal Limited Partnership and HoustonLink Pipeline Company LLC. At December 31, 2018 and 2017, the Canaport Energy East Marine Terminal Limited Partnership investment was nil.

7 At December 31, 2018, the difference between the carrying value of the investment and the underlying equity in the net assets of Bruce Power was $870 million (2017 – $902 million) due to the fair value assessment of assets at the time of acquisitions.

8 At December 31, 2018, the difference between the carrying value of the investment and the underlying equity in the net assets of Portlands Energy was $73 million (2017 – $73 million) due mainly to interest capitalized during construction.

TransGas de Occidente S.A. Impairment

In August 2017, TransCanada recognized an impairment charge of$12 million on its 46.5 per cent equity investment in TransGas de Occidente S.A. (TransGas). TransGas constructed and operated a natural gas pipeline in Colombia for a 20-year contract term. As per the terms of the agreement, upon completion of the 20-year contract in August 2017, TransGas transferred its pipeline assets to Transportadora de Gas Internacional S.A. The non-cash impairment charge represented the write-down of the remaining carrying value of the equity investment which was recognized in Income from equity investments in the Consolidated statement of income.

Canaport Energy East Marine Terminal Limited Partnership Impairment

On October 5, 2017, the Company informed the NEB that it will not be proceeding with the Energy East, Eastern Mainline and Upland projects. As a result, in October 2017, the Company recognized a non-cash impairment charge of $20 million in Income from equity investments in its Liquids Pipelines segment which represented the carrying value of the equity investment in the Canaport Energy East Marine Terminal Limited Partnership. Due to the inability to reach a regulatory decision for this project, there were no recoveries of costs from third parties.

ASTC Power Partnership Impairment

In March 2016, TransCanada issued notice to the Balancing Pool of the decision to terminate its Sundance B PPA held through ASTC Power Partnership. In accordance with a provision in the PPA, a buyer was permitted to terminate the arrangement if a change in law occurs that makes the arrangement unprofitable or more unprofitable. As a result of changes in law surrounding the Alberta Specified Gas Emitters Regulation, the Company expected increasing costs related to carbon emissions to continue throughout the remaining term of the PPA resulting in increasing unprofitability. As a result, in first quarter 2016, the Company recognized a non-cash impairment charge of $29 million ($21 million after tax) in its Energy segment Income from equity investments which represented the carrying value of the equity investment in ASTC Partnership. The PPA termination was settled in December 2016.

Distributions and Contributions

Distributions received from equity investments for the year ended December 31, 2018 were $1,106 million (2017 – $1,332 million; 2016 – $1,571 million) of which $121 million (2017 – $362 million; 2016 – $727 million) was included in Investing activities in the Consolidated statement of cash flows with respect to distributions received from Bruce Power from its financing program.

Contributions made to equity investments for the year ended December 31, 2018 were $1,015 million (2017 – $1,681 million; 2016 – $765 million) and are included in Investing activities in the Consolidated statement of cash flows. For 2018, contributions include $179 million (2017 – $977 million) related to TransCanada's proportionate share of the Sur de Texas debt financing requirements.

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian $)	2018	2017	2016
Income			
Revenues	**4,836**	4,913	4,336
Operating and other expenses	**(3,545)**	(2,993)	(3,068)
Net income	**1,515**	1,636	1,080
Net income attributable to TransCanada	**714**	773	514

at December 31 (millions of Canadian $)	2018	2017
Balance Sheet		
Current assets	**2,209**	2,176
Non-current assets	**20,647**	17,869
Current liabilities	**(2,049)**	(1,577)
Non-current liabilities	**(9,042)**	(8,217)

Loan receivable from affiliate

TransCanada holds a 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline. In 2017, TransCanada 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, 2018, the Company's consolidated balance sheet included a MXN$18.9 billion or $1.3 billion (2017 – MXN$14.4 billion or $0.9 billion) loan receivable from the Sur de Texas joint venture which represents TransCanada's proportionate share of long-term debt financing requirements related to the joint venture. Interest income and other included interest income of $120 million in 2018 (2017 – $34 million) from this joint venture with a corresponding proportionate share of interest expense recorded in Income from equity investments.

10. RATE-REGULATED BUSINESSES

TransCanada's businesses that apply RRA currently include certain Canadian, U.S. and Mexico natural gas pipelines, and certain regulated 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 expenses and credits 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 included in future service rates and recovered from or refunded to customers in subsequent years.

Canadian Regulated Operations

TransCanada's Canadian natural gas pipelines are regulated by the NEB under the National Energy Board Act. The NEB 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.

TransCanada's Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and return on capital as approved by the 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 are described below.

NGTL System

NGTL's 2018 results reflect the terms of the 2018-2019 Revenue Requirement Settlement (the 2018-2019 Settlement) approved by the NEB in June 2018. This two-year settlement includes an ROE of 10.1 per cent on 40 per cent deemed common equity, a composite depreciation rate of approximately 3.5 per cent, a mechanism for sharing variances above and below a fixed annual operating, maintenance and administration (OM&A) cost 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 of the settlement include an ROE of 10.1 per cent on deemed common equity of 40 per cent, an incentive mechanism that has both upside and downside risk and a $20 million after-tax annual TransCanada contribution to reduce the revenue requirement. Toll stabilization is 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 TransCanada 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 (NEB 2018 Decision) 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.

U.S. Regulated Operations

TransCanada's U.S. regulated natural gas pipelines operate under the provisions of the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 (NGA) and the Energy Policy Act of 2005, and are subject to the jurisdiction of the FERC. The NGA grants the 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 U.S. Tax Reform and income taxes for rate-making purposes in a master limited partnership (MLP) that impact future earnings and cash flows of FERC-regulated pipelines. The 2018 FERC Actions also established a process and schedule by which all FERC-regulated interstate pipelines and natural gas storage facilities had to either (i) file a new uncontested rate settlement or (ii) file a FERC Form 501-G that quantifies the isolated impact of U.S. Tax Reform on FERC-regulated pipelines and natural gas storage assets as well as the impact of the 2018 FERC Actions on pipelines held by MLPs.

The impact of the 2018 FERC Actions on the Company's more significant U.S. regulated natural gas pipelines is included below.

Columbia Gas
Columbia Gas' natural gas transportation and storage services are provided under a tariff at rates subject to FERC approval. In 2013, the FERC approved a modernization settlement which provides for cost recovery and return on investment of up to US$1.5 billion over a five-year period to modernize the Columbia Gas system to improve system integrity and enhance service reliability and flexibility. In March 2016, an extension of this settlement was approved by the FERC, which will allow for the cost recovery and return on additional expanded scope investment of US$1.1 billion over a three-year period through 2020.

In response to the 2018 FERC Actions, Columbia Gas filed a Form 501-G including a statement explaining its rationale why the pipeline’s rates are not required to change.

ANR Pipeline
ANR Pipeline operates under rates established under a FERC-approved rate settlement in 2016. Under terms of the 2016 settlement, neither ANR Pipeline nor the settling parties could file for new rates to become effective earlier than August 1, 2019. However, ANR Pipeline is required to file for new rates to be effective no later than August 1, 2022.

In December 2018, ANR Pipeline filed a Form 501-G including a statement explaining its rationale why the pipeline’s rates are not required to change.

Columbia Gulf
Columbia Gulf’s natural gas transportation services are provided under a tariff at rates subject to FERC approval. In September 2016, FERC issued an order approving an uncontested settlement following a FERC-initiated rate proceeding pursuant to Section 5 of the NGA, which required a reduction in Columbia Gulf’s daily maximum recourse rate and addressed treatment of post-retirement benefits other than pensions, pension expense and regulatory expenses. The FERC order also required Columbia Gulf to file a general rate case under section 4 of the NGA by January 31, 2020, for rates to take effect by August 1, 2020.

In response to the 2018 FERC Actions, Columbia Gulf filed a Form 501-G including a statement explaining its rationale why the pipeline’s rates are not required to change.

TC PipeLines, LP
TransCanada owns a 25.5 per cent interest in TC PipeLines, LP, which has ownership interests in eight wholly-owned or partially-owned natural gas pipelines serving major markets in the U.S. As TC PipeLines, LP is an MLP, all pipelines it owns wholly or in part were potentially impacted by the 2018 FERC Actions which creates a presumption that entities whose earnings are not taxed through a corporation should not be permitted to recover an income tax allowance in their regulated cost-of-service rates. Additionally, to the extent an entity’s income tax allowance is eliminated from rates, it must also eliminate its existing accumulated deferred income tax (ADIT) balance from its rate base. Refer to Note 16, Income Taxes for further information regarding the impact of these changes to TransCanada.

Great Lakes
Great Lakes reached a rate settlement with its customers, which was approved by FERC on February 22, 2018, decreasing Great Lakes' maximum transportation rates by 27 per cent effective October 1, 2017. This settlement does not contain a moratorium and 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 Section 4 filing which had the effect of reducing rates by 2 per cent from what was in place prior to the FERC changes in 2018. The reduction in rates became effective on February 1, 2019 after the limited Section 4 filing was accepted by FERC on January 31, 2019.

Mexico Regulated Operations

TransCanada's Mexico natural gas pipelines are regulated by the CRE and operate in accordance with CRE-approved tariffs. The rates in effect on TransCanada's Mexico natural gas pipelines were established based on CRE-approved contracts that provide for the recovery of costs of providing services and a return on and of invested capital.

Regulatory Assets and Liabilities

at December 31 (millions of Canadian $)	2018	2017	Remaining Recovery/ Settlement Period (years)
Regulatory Assets			
Deferred income taxes[1]	**1,051**	940	n/a
Operating and debt-service regulatory assets[2]	**12**	—	1
Pensions and other post-retirement benefits[1,3]	**379**	388	n/a
Foreign exchange on long-term debt[1,4]	**46**	—	1-11
Other	**143**	71	n/a
	1,631	1,399	
Less: Current portion included in Other current assets (Note 7)	**83**	23	
	1,548	1,376	
Regulatory Liabilities			
Operating and debt-service regulatory liabilities[2]	**96**	188	1
Pensions and other post-retirement benefits[3]	**53**	164	n/a
ANR related post-employment and retirement benefits other than pension[5]	**54**	66	n/a
Long term adjustment account[6]	**1,015**	1,142	2-45
Bridging amortization account[6]	**305**	202	12
Pipeline abandonment trust balance	**1,113**	825	n/a
Cost of removal[7]	**261**	216	n/a
Deferred income taxes	**165**	75	n/a
Deferred income taxes – U.S. Tax Reform[8]	**1,394**	1,659	n/a
Other	**65**	47	n/a
	4,521	4,584	
Less: Current portion included in Accounts payable and other (Note 14)	**591**	263	
	3,930	4,321	

1 These regulatory assets are underpinned by non-cash transactions or are recovered without an allowance for return as approved by the regulator. Accordingly, these regulatory assets are not included in rate base and do not yield a return on investment during the recovery period.

2 Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances approved by the regulator for inclusion in determining tolls for the following calendar year.

3 These balances represent the regulatory offset to pension plan and other post-retirement obligations to the extent the amounts are expected to be collected from or refunded to customers in future rates.

4 Foreign exchange on long-term debt of the NGTL System represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate at the time of issue. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls.

5 This balance represents the 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 September 2016 rate settlement, $11 million (US$8 million) of the regulatory liability balance at December 31, 2018 (2017 – $26 million; US$21 million) which accumulated between January 2007 and July 2016 will be fully amortized at July 31, 2019. The remaining $43 million (US$32 million) balance accumulated prior to 2007 is subject to resolution through future regulatory proceedings and, accordingly, a settlement period cannot be determined at this time.

6 These regulatory accounts are used to capture Canadian Mainline revenue and cost variances plus toll stabilization during the 2015-2030 settlement term. The 2018 LTAA balance of $ 1,015 million consists of $932 million to be amortized over two years with the remaining balance to be amortized over 45 years.

7 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.

8 These balances represent the impact of U.S. Tax Reform. 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. See Note 16, Income taxes, for further information on U.S. Tax Reform.

11. GOODWILL

The Company has recorded the following Goodwill on its acquisitions:

(millions of Canadian $)	U.S. Natural Gas Pipelines
Balance at January 1, 2017	13,958
Columbia adjustment (Note 26)	71
Foreign exchange rate changes	(945)
Balance at December 31, 2017	13,084
Tuscarora impairment charge	**(79)**
Foreign exchange rate changes	**1,173**
Balance at December 31, 2018	**14,178**

Tuscarora

In the fourth quarter of 2018, the Company finalized its regulatory filing for Tuscarora in response to the 2018 FERC Actions and Form 501-G requirements. In January 2019, Tuscarora reached a settlement-in-principle with its customers which was filed with FERC. As a result of these developments, as well as changes to other valuation assumptions responsive to Tuscarora's commercial environment, it was determined that the fair value of Tuscarora did not exceed its carrying value, including goodwill. The fair value of the reporting unit was determined using a discounted cash flow analysis. The expected cash flows were discounted using a risk-adjusted discount rate to determine the fair value. As a result, the Company recorded a goodwill impairment charge of $79 million pre-tax within the U.S. Natural Gas Pipelines segment. This non-cash charge was recorded in Goodwill and other asset impairment charges on the Consolidated statement of income. As Tuscarora is a TC PipeLines, LP asset, the Company's share of this amount, after tax and net of non-controlling interests, was $15 million. The goodwill balance related to Tuscarora at December 31, 2018 wasUS$23 million (2017 – US$82 million).

Great Lakes

At December 31, 2018, the estimated fair value of Great Lakes exceeded its carrying value by less than10 per cent. The fair value of this reporting unit was measured using a discounted cash flow analysis in its most recent valuation. Assumptions used in the analysis regarding Great Lakes' ability to realize long-term value in the North American energy market included the impact of its 501-G election, revenue opportunities on the system as well as changes to other valuation assumptions responsive to Great Lakes' commercial environment. Although evolving market conditions and other factors relevant to Great Lakes' long term financial performance have been positive, there is a risk that reductions in future cash flow forecasts or adverse changes in other key assumptions could result in a future impairment of a portion of the goodwill balance relating to Great Lakes. The goodwill balance related to Great Lakes at December 31, 2018 was US$573 million (2017 – US$573 million).

Ravenswood

As a result of information received during the process to monetize the Company's U.S. Northeast power business in third quarter 2016, it was determined that the fair value of Ravenswood did not exceed its carrying value, including goodwill. The fair value of the reporting unit was determined using a combination of methods including a discounted cash flow analysis and a range of expected consideration from a potential sale. The expected cash flows were discounted using a risk-adjusted discount rate to determine the fair value. As a result, in 2016, the Company recorded a goodwill impairment charge on the full carrying value of Ravenswood goodwill of $1,085 million ($656 million after tax) within the Energy segment.

12. INTANGIBLE AND OTHER ASSETS

at December 31 (millions of Canadian $)	2018	2017
Capital projects in development	**1,051**	596
Deferred income tax assets (Note 16)	**322**	316
Employee post-retirement benefits (Note 23)	**192**	193
Fair value of derivative contracts (Note 24)	**61**	73
Other	**295**	306
	1,921	1,484

Capital projects in development

Keystone XL

In January 2018, the Company recommenced capitalizing development costs related to Keystone XL. In addition, certain project costs that were recorded in Plant, property and equipment at December 31, 2017 were transferred to Capital projects in development in 2018. These costs were related to the net realizable value of Keystone XL assets after an impairment charge was recorded in 2015. As a result, at December 31, 2018, Capital projects in development for this project were $0.8 billion (2017 – nil).

Reimbursement of Coastal GasLink pipeline costs

In accordance with provisions in the agreements with the LNG Canada joint venture participants, all five parties elected to reimburse TransCanada for their share of costs incurred prior to receiving the Final Investment Decision (FID) on the Coastal GasLink pipeline project. In November 2018, the Company received payments totaling $470 million which were recorded as a reduction of the carrying value of Coastal GasLink.

Prince Rupert Gas Transmission

In July 2017, the Company was notified that Pacific Northwest LNG would not be proceeding with its proposed LNG project and that Progress Energy (Progress) would be terminating its agreement with TransCanada for the development of the PRGT project effective August 10, 2017. In accordance with the terms of the agreement, all project costs incurred to advance the project, including carrying charges, were fully recoverable upon termination. In October 2017, the Company received full payment of the$634 million reimbursement from Progress.

Energy East and Related Projects Impairment

On October 5, 2017, the Company informed the NEB that it will not proceed with the Energy East, Eastern Mainline and Upland projects. Based on this decision, the Company evaluated its Capital projects in development balance related to the Energy East and Upland projects including AFUDC. As a result, the Company recognized a non-cash impairment charge of $1,153 million ($870 million after tax) in the Liquids Pipelines segment. Due to the inability to reach a regulatory decision for this project, there were no recoveries of costs from third parties. The non-cash charge was recorded in Goodwill and other asset impairment charges on the Consolidated statement of income.

Power Purchase Arrangements Impairment

In March 2016, TransCanada terminated its Sheerness and Sundance A PPAs. In accordance with a provision in the PPAs, a buyer was permitted to terminate the arrangement if a change in law occurs that makes the arrangement unprofitable or more unprofitable. The Company expected increasing costs related to carbon emissions to continue throughout the remaining terms of the PPAs resulting in increasing unprofitability. As such, in 2016, the Company recognized a non-cash impairment charge of $211 million ($155 million after tax) in its Energy segment, representing the carrying value of the PPAs which was recorded in Intangible and other assets. In December 2016, TransCanada transferred to the Balancing Pool a package of environmental credits that were being held to offset the PPA emissions costs and recorded a non-cash charge of $92 million ($68 million after tax) related to the carrying value of these environmental credits.

13. NOTES PAYABLE

(millions of Canadian $, unless otherwise noted)	2018 Outstanding at December 31	2018 Weighted Average Interest Rate per Annum at December 31	2017 Outstanding at December 31	2017 Weighted Average Interest Rate per Annum at December 31
Canada	**2,117**	**2.5%**	884	1.6%
U.S. (2018 – US$448; 2017 – US$688)	**611**	**3.1%**	862	2.2%
Mexico (2018 – US$25; 2017 – MXN$275)	**34**	**3.3%**	17	8.0%
	2,762		1,763	

At December 31, 2018, Notes payable consists of short-term borrowings in Canada by TransCanada PipeLines Limited (TCPL), in the U.S. by TransCanada PipeLine USA Ltd. (TCPL USA) and TransCanada American Investments Ltd. (TAIL), and in Mexico by a Mexican subsidiary.

At December 31, 2018, total committed revolving and demand credit facilities were $12.9 billion (2017 – $11.0 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)			2018		2017
Borrower	**Description**	**Matures**	**Total Facilities**	**Unused Capacity**	**Total Facilities**
Committed, syndicated, revolving, extendible, senior unsecured credit facilities[1]:					
TCPL	Supports TCPL's Canadian dollar commercial paper program and for general corporate purposes	December 2023	**3.0**	**3.0**	3.0
TCPL/TCPL USA/Columbia/TAIL	Supports TCPL, TCPL USA and TAIL's U.S. dollar commercial paper programs and is used for general corporate purposes of the borrowers, guaranteed by TCPL	December 2019	**US 4.5**	**US 4.5**	—
TCPL/TCPL USA/Columbia/TAIL	Used for general corporate purposes of the borrowers, guaranteed by TCPL	December 2021	**US 1.0**	**US 1.0**	—
TCPL	Supports TCPL's U.S. dollar commercial paper program and for general corporate purposes		**—**	**—**	US 2.0
TCPL USA	Used for TCPL USA general corporate purposes, guaranteed by TCPL		**—**	**—**	US 1.0
Columbia	Used for Columbia general corporate purposes, guaranteed by TCPL		**—**	**—**	US 1.0
TAIL	Supports TAIL's U.S. dollar commercial paper program and for general corporate purposes, guaranteed by TCPL		**—**	**—**	US 0.5
Demand senior unsecured revolving credit facilities[1]:					
TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity, TCPL USA facility guaranteed by TCPL	Demand	**2.1**	**1.0**	1.9
Mexico subsidiary	Used for Mexico general corporate purposes, guaranteed by TCPL	Demand	**MXN 5.0**	**MXN 4.5**	MXN 5.0

1 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, 2018, the Company was in compliance with all debt covenants.

For the year ended December 31, 2018, the cost to maintain the above facilities was $12 million (2017 – $7 million; 2016 – $10 million).

At December 31, 2018, the Company's operated affiliates had an additional $0.8 billion (2017 – $0.4 billion) of undrawn capacity on committed credit facilities.

14. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	2018	2017
Trade payables	**3,224**	2,847
Fair value of derivative contracts (Note 24)	**922**	387
Unredeemed shares of Columbia	**357**	312
Regulatory liabilities (Note 10)	**591**	263
Other	**314**	248
	5,408	4,057

15. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	2018	2017
Employee post-retirement benefits (Note 23)	**569**	389
Asset retirement obligations	**90**	98
Fair value of derivative contracts (Note 24)	**42**	72
Guarantees (Note 27)	**12**	16
Other	**295**	152
	1,008	727

16. INCOME TAXES

U.S. Tax Reform

On December 22, 2017, the President of the United States signed H.R.1, the Tax Cuts and Jobs Act (U.S. Tax Reform or the Act) into law. As a result, among other things, the enacted U.S. federal corporate income tax rate was reduced from 35 per cent to 21 per cent effective January 1, 2018 and resulted in a remeasurement of existing deferred income tax assets and deferred income tax liabilities related to the Company's U.S. businesses to reflect the new lower income tax rate as at December 31, 2017.

For the Company’s U.S. businesses not subject to RRA, the reduction in enacted income tax rates resulted in a decrease in net deferred income tax liabilities and a deferred income tax recovery of $816 million in 2017. For the Company’s U.S. businesses subject to RRA, the reduction in income tax rates resulted in a reduction in net deferred income tax liabilities and the recognition of a net regulatory liability of $1,686 million on the Consolidated balance sheet at December 31, 2017.

Net deferred income tax liabilities related to the cumulative remeasurements of employee post-retirement benefits included in AOCI were also adjusted with a corresponding increase in deferred income tax expense of $12 million in 2017.

Given the significance of the legislation, the U.S. Securities and Exchange Commission (SEC) staff issued guidance which allowed registrants to record provisional amounts at December 31, 2017 which may be adjusted as information becomes available, prepared or analyzed during a measurement period not to exceed one year. The SEC guidance summarized a three-step process to be applied at each reporting period to identify: (1) where the accounting is complete; (2) provisional amounts where the accounting is not yet complete, but a reasonable estimate has been determined; and (3) where a reasonable estimate cannot yet be determined and therefore income taxes are reflected in accordance with law prior to the enactment of the Act.

At December 31, 2017, the Company considered amounts recorded related to U.S. Tax Reform to be reasonable estimates, however, certain amounts were provisional as the Company's interpretation, assessment and presentation of the impact of the tax law change were further clarified with additional guidance from regulatory, tax and accounting authorities received in 2018. With additional guidance provided during the one-year measurement period and upon finalizing its 2017 annual tax return for its U.S. businesses, in fourth quarter 2018 the Company recognized further adjustments to its deferred income tax liability and net regulatory liability balances as well as a deferred income tax recovery of $52 million in fourth quarter 2018.

In addition, the 2018 FERC Actions established that, to the extent an entity's income tax allowance should be eliminated from rates, it must also eliminate its existing ADIT balance from its rate base. In accordance with the FERC Form 501-G and uncontested rate settlement filings, the ADIT balances for all pipelines held wholly or in part by TC PipeLines, LP were eliminated from their respective rate bases. As a result, net regulatory liabilities recorded for these assets pursuant to U.S. Tax Reform were written off, resulting in a further deferred income tax recovery of $115 million in fourth quarter 2018.

Commencing January 1, 2018, the Company amortized the net regulatory liabilities, recorded per U.S. Tax Reform, using the Reverse South Georgia methodology. Under this methodology, rate-regulated entities determine and immediately begin recording amortization based on their composite depreciation rates. In 2018, amortization of these net regulatory liabilities in the amount of $58 million was recorded and included in Revenues in the Consolidated statement of income. The net regulatory liability related to U.S. Tax Reform at December 31, 2018 was $1,394 million (2017 – $1,686 million).

Further to U.S. Tax Reform, the U.S. Treasury and the U.S. Internal Revenue Service issued proposed regulations in November and December of 2018 which provided administrative guidance and clarified certain aspects of the new laws with respect to interest deductibility, base erosion and anti-abuse tax, the new dividend received deduction and anti-hybrid rules. Based on the Company's review and analysis of these proposed regulations, no material adjustments were recorded in the 2018 Consolidated financial statements. The proposed regulations are complex and comprehensive, and considerable uncertainty continues to exist until the final regulations are released, which is expected to occur later in 2019. TransCanada continues to review and analyze these proposed regulations as well as assess their potential impact on the Company.

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	2018	2017	2016
Current			
Canada	**65**	113	116
Foreign	**250**	36	40
	315	149	156
Deferred			
Canada	**49**	(185)	101
Foreign	**235**	751	95
Foreign – U.S. Tax Reform and 2018 FERC Actions	**(167)**	(804)	—
	117	(238)	196
Income Tax Expense/(Recovery)	**432**	(89)	352

Geographic Components of Income before Income Taxes

year ended December 31 (millions of Canadian $)	2018	2017	2016
Canada	**433**	(339)	219
Foreign	**3,516**	3,645	618
Income before Income Taxes	**3,949**	3,306	837

Reconciliation of Income Tax Expense/(Recovery)

year ended December 31 (millions of Canadian $)	2018	2017	2016
Income before income taxes	**3,949**	3,306	837
Federal and provincial statutory tax rate	**27%**	27%	27%
Expected income tax expense	**1,066**	893	226
U.S. Tax Reform and 2018 FERC Actions	**(167)**	(804)	—
Foreign income tax rate differentials	**(432)**	(81)	(196)
Loss/(income) from equity investments and non-controlling interests	**50**	(64)	(68)
Income tax differential related to regulated operations	**(54)**	(42)	81
Non-taxable portion of capital gains	**(11)**	(42)	—
Asset impairment charges[1]	**—**	34	242
Non-deductible amounts	**—**	4	46
Other	**(20)**	13	21
Income Tax Expense/(Recovery)	**432**	(89)	352

1 Net of nil (2017 – nil, 2016 – $112 million) attributed to higher foreign tax rates.

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	2018	2017
Deferred Income Tax Assets		
Tax loss and credit carryforwards	**1,238**	1,379
Difference in accounting and tax bases of impaired assets and assets held for sale	**574**	651
Regulatory and other deferred amounts	**858**	512
Unrealized foreign exchange losses on long-term debt	**491**	216
Financial instruments	**—**	10
Other	**292**	227
	3,453	2,995
Less: valuation allowance	**1,159**	832
	2,294	2,163
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment and PPAs	**6,449**	6,240
Equity investments	**1,069**	632
Taxes on future revenue requirement	**300**	238
Other	**180**	140
	7,998	7,250
Net Deferred Income Tax Liabilities	**5,704**	5,087

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

at December 31 (millions of Canadian $)	2018	2017
Deferred Income Tax Assets		
Intangible and other assets (Note 12)	**322**	316
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**6,026**	5,403
Net Deferred Income Tax Liabilities	**5,704**	5,087

At December 31, 2018, the Company has recognized the benefit of unused non-capital loss carryforwards of $1,867 million (2017 – $1,280 million) for federal and provincial purposes in Canada, which expire from 2030 to 2038. The Company has not recognized the benefit of capital loss carry forwards of $821 million (2017 – $668 million) for federal and provincial purposes in Canada. The Company also has recognized the benefit of Ontario minimum tax credits of $91 million (2017 – $82 million), which expire from 2026 to 2038.

At December 31, 2018, the Company has recognized the benefit of unused net operating loss carryforwards of US$889 million (2017 – US$1,800 million) for federal purposes in the U.S., which expire from 2029 to 2037. The Company has not recognized the benefit of unused net operating loss carryforwards of US$706 million (2017 – US$710 million) for federal purposes in the U.S. The Company also has recognized the benefit of alternative minimum tax credits of US$1 million (2017 – US$56 million).

At December 31, 2018, the Company has recognized the benefit of unused net operating loss carryforwards of US$3 million (2017 – US$7 million) in Mexico, which expire from 2024 to 2028.

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, 2018 by approximately $619 million (2017 – $569 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $338 million, net of refunds, were made in 2018 (2017 – payments, net of refunds, of $247 million; 2016 – payments, net of refunds, of $105 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 $)	2018	2017	2016
Unrecognized tax benefit at beginning of year	**15**	18	17
Gross increases – tax positions in prior years	**13**	—	3
Gross decreases – tax positions in prior years	**(5)**	(1)	—
Gross increases – tax positions in current year	**—**	2	2
Settlement	**—**	—	(1)
Lapse of statutes of limitations	**(4)**	(4)	(3)
Unrecognized Tax Benefit at End of Year	**19**	15	18

Subject to the results of audit examinations by taxing authorities and other legislative amendments, TransCanada 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.

TransCanada 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 2010. Substantially all material U.S. federal, state and local income tax matters have been concluded for years through 2011.

TransCanada'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, 2018 reflects $1 million of interest recovery and nil for penalties (2017 – nil of interest expense and nil for penalties; 2016 – nil of interest expense and nil for penalties). At December 31, 2018, the Company had $3 million accrued for interest expense and nil accrued for penalties (December 31, 2017 – $4 million accrued for interest expense and nil accrued for penalties).

17. LONG-TERM DEBT

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2018 Outstanding at December 31	2018 Interest Rate[1]	2017 Outstanding at December 31	2017 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian	2019 to 2020	**350**	**11.4%**	500	10.8%
U.S. (2018 and 2017 – US$400)	2021	**546**	**9.9%**	501	9.9%
Medium Term Notes					
Canadian	2019 to 2048	**7,504**	**4.8%**	6,504	4.9%
Senior Unsecured Notes					
U.S. (2018 – US$17,192; 2017 – US$14,892)	2019 to 2049	**23,456**	**5.1%**	18,644	5.1%
		31,856		26,149	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian	2024	**100**	**9.9%**	100	9.9%
U.S. (2018 and 2017 – US$200)	2023	**273**	**7.9%**	250	7.9%
Medium Term Notes					
Canadian	2025 to 2030	**504**	**7.4%**	504	7.4%
U.S. (2018 and 2017 – US$33)	2026	**44**	**7.5%**	41	7.5%
		921		895	
COLUMBIA PIPELINE GROUP, INC.					
Senior Unsecured Notes					
U.S. (2018 – US$2,250; 2017 – US$2,750)[2]	2020 to 2045	**3,070**	**4.4%**	3,443	4.0%
TC PIPELINES, LP					
Unsecured Loan Facility					
U.S. (2018 – US$40; 2017 – US$185)	2021	**55**	**3.8%**	232	2.7%
Unsecured Term Loan					
U.S. (2018 – US$500; 2017 – US$670)[3]	2022	**682**	**3.6%**	839	2.7%
Senior Unsecured Notes					
U.S. (2018 and 2017 – US$1,200)	2021 to 2027	**1,637**	**4.4%**	1,502	4.4%
		2,374		2,573	
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2018 and 2017 – US$672)	2021 to 2026	**918**	**7.2%**	842	7.2%
GAS TRANSMISSION NORTHWEST LLC					
Unsecured Term Loan					
U.S. (2018 – US$35; 2017 – US$55)	2019	**48**	**3.3%**	69	1.1%
Senior Unsecured Notes					
U.S. (2018 and 2017 – US$250)	2020 to 2035	**341**	**5.6%**	313	5.6%
		389		382	
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. (2018 – US$240; 2017 – US$259)	2021 to 2030	**327**	**7.7%**	324	7.7%

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2018 Outstanding at December 31	2018 Interest Rate[1]	2017 Outstanding at December 31	2017 Interest Rate[1]
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Unsecured Loan Facility					
U.S. (2018 – US$19; 2017 – nil)	2023	**26**	**3.6%**	—	—
Senior Secured Notes[4]					
U.S. (2018 – nil; 2017 – US$30)		**—**	**—**	38	6.0%
		26		38	
TUSCARORA GAS TRANSMISSION COMPANY					
Unsecured Term Loan					
U.S. (2018 – US$24; 2017 – US$25)	2020	**33**	**3.5%**	31	1.1%
NORTH BAJA PIPELINE, LLC					
Unsecured Term Loan					
U.S. (2018 – US$50; 2017 – nil)	2021	**68**	**3.5%**	—	—
		39,982		34,677	
Current portion of long-term debt		**(3,462)**		(2,866)	
Unamortized debt discount and issue costs		**(241)**		(174)	
Fair value adjustments[5]		**230**		238	
		36,509		31,875	

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, premium 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 The US$500 million term loan facility was amended in September 2017 to extend the maturity dates from 2018 to 2022.

4 These notes were secured by shipper transportation contracts, existing and new guarantees, letters of credit and collateral requirements.

5 The fair value adjustments include $232 million (2017 – $ 242 million) related to the acquisition of Columbia. The fair value adjustments also include a decrease of $ 2 million (2017 – $ 4 million) related to hedged interest rate risk. Refer to Note 24, Risk management and financial instruments, for further information.

Principal Repayments

At December 31, 2018, principal repayments for the next five years on the Company's long-term debt are approximately as follows:

(millions of Canadian $)	2019	2020	2021	2022	2023
Principal repayments on long-term debt	3,465	2,834	2,098	2,100	1,930

Long-Term Debt Issued

The Company issued long-term debt over the three years ended December 31, 2018 as follows:

(millions of Canadian $, unless otherwise noted)					
Company	**Issue Date**	**Type**	**Maturity Date**	**Amount**	**Interest Rate**
TRANSCANADA PIPELINES LIMITED					
	October 2018	Senior Unsecured Notes	March 2049	US 1,000	5.10%
	October 2018	Senior Unsecured Notes	May 2028	US 400	4.25% [1]
	July 2018	Medium Term Notes	July 2048	800	4.18%
	July 2018	Medium Term Notes	March 2028	200	3.39% [2]
	May 2018	Senior Unsecured Notes	May 2028	US 1,000	4.25%
	May 2018	Senior Unsecured Notes	May 2048	US 1,000	4.875%
	May 2018	Senior Unsecured Notes	May 2038	US 500	4.75%
	November 2017	Senior Unsecured Notes	November 2019	US 550	Floating
	November 2017	Senior Unsecured Notes	November 2019	US 700	2.125%
	September 2017	Medium Term Notes	March 2028	300	3.39%
	September 2017	Medium Term Notes	September 2047	700	4.33%
	June 2016	Acquisition Bridge Facility[3]	June 2018	US 5,213	Floating
	June 2016	Medium Term Notes	July 2023	300	3.69% [4]
	June 2016	Medium Term Notes	June 2046	700	4.35%
	January 2016	Senior Unsecured Notes	January 2026	US 850	4.875%
	January 2016	Senior Unsecured Notes	January 2019	US 400	3.125%
NORTH BAJA PIPELINE, LLC					
	December 2018	Unsecured Term Loan	December 2021	US 50	Floating
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
	April 2018	Unsecured Loan Facility	April 2023	US 19	Floating
TUSCARORA GAS TRANSMISSION COMPANY					
	August 2017	Unsecured Term Loan	August 2020	US 25	Floating
	April 2016	Unsecured Term Loan	April 2019	US 10	Floating
TC PIPELINES, LP					
	May 2017	Senior Unsecured Notes	May 2027	US 500	3.90%
TRANSCANADA PIPELINE USA LTD.					
	June 2016	Acquisition Bridge Facility[3]	June 2018	US 1,700	Floating
ANR PIPELINE COMPANY					
	June 2016	Senior Unsecured Notes	June 2026	US 240	4.14%

1 Reflects coupon rate on re-opening of a pre-existing senior unsecured notes issue. The notes were issued at a discount to par, resulting in a re-issuance yield of 4.439 per cent.

2 Reflects coupon rate on re-opening of a pre-existing medium term notes (MTN) issue. The MTNs were issued at a discount to par, resulting in a re-issuance yield of 3.41 per cent.

3 These facilities were put in place to finance a portion of the Columbia acquisition and bear interest at LIBOR plus an applicable margin. Proceeds from the issuance of common shares in fourth quarter 2016 and proceeds from the sale of the U.S. Northeast power assets were used to fully retire the remaining acquisition bridge facilities in second quarter 2017.

4 Reflects coupon rate on re-opening of a pre-existing MTN issue. The MTNs were issued at premium to par, resulting in a re-issuance yield of 2.69 per cent.

Long-Term Debt Retired

The Company retired/repaid long-term debt over the three years ended December 31, 2018 as follows:

(millions of Canadian $, unless otherwise noted) Company	Retirement/Repayment Date	Type	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED				
	August 2018	Senior Unsecured Notes	US 850	6.50%
	March 2018	Debentures	150	9.45%
	January 2018	Senior Unsecured Notes	US 500	1.875%
	January 2018	Senior Unsecured Notes	US 250	Floating
	December 2017	Debentures	100	9.80%
	November 2017	Senior Unsecured Notes	US 1,000	1.625%
	June 2017	Acquisition Bridge Facility[1]	US 1,513	Floating
	February 2017	Acquisition Bridge Facility[1]	US 500	Floating
	January 2017	Medium Term Notes	300	5.10%
	November 2016	Acquisition Bridge Facility[1]	US 3,200	Floating
	October 2016	Medium Term Notes	400	4.65%
	June 2016	Senior Unsecured Notes	US 84	7.69%
	June 2016	Senior Unsecured Notes	US 500	Floating
	January 2016	Senior Unsecured Notes	US 750	0.75%
TC PIPELINES, LP				
	December 2018	Unsecured Term Loan	US 170	Floating
COLUMBIA PIPELINE GROUP, INC.				
	June 2018	Senior Unsecured Notes	US 500	2.45%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM				
	May 2018	Senior Secured Notes	US 18	5.90%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP				
	March 2018	Senior Unsecured Notes	US 9	6.73%
TUSCARORA GAS TRANSMISSION COMPANY				
	August 2017	Senior Secured Notes	US 12	3.82%
TRANSCANADA PIPELINE USA LTD.				
	June 2017	Acquisition Bridge Facility[1]	US 630	Floating
	April 2017	Acquisition Bridge Facility[1]	US 1,070	Floating
NOVA GAS TRANSMISSION LTD.				
	February 2016	Debentures	225	12.20%

1 These facilities were put in place to finance a portion of the Columbia acquisition and were fully retired in second quarter 2017.

Interest Expense

Interest expense in the three years ended December 31 was as follows:

year ended December 31 (millions of Canadian $)	2018	2017	2016
Interest on long-term debt	**1,877**	1,794	1,765
Interest on junior subordinated notes	**391**	348	180
Interest on short-term debt	**73**	33	18
Capitalized interest	**(124)**	(173)	(176)
Amortization and other financial charges[1]	**48**	67	211
	2,265	2,069	1,998

1 Amortization and other financial charges includes amortization of transaction costs and debt discounts calculated using the effective interest method and changes in the fair value of derivatives used to manage the Company's exposure to changes in interest rates. In 2016, this amount includes dividend equivalent payments of $109 million on the subscription receipts issued to partially fund the Columbia acquisition. Refer to Note 20, Common shares, for further information.

The Company made interest payments of $2,156 million in 2018 (2017 – $1,987 million; 2016 – $1,721 million) on long-term debt, junior subordinated notes and short-term debt, net of interest capitalized.

18. JUNIOR SUBORDINATED NOTES

Outstanding loan amount (millions of Canadian $, unless otherwise noted)	Maturity Date	2018 Outstanding at December 31	2018 Effective Interest Rate[1]	2017 Outstanding at December 31	2017 Effective Interest Rate[1]
TRANSCANADA PIPELINES LIMITED[2]					
US$1,000 notes issued 2007 at 6.35%[3]	2067	**1,364**	**5.6%**	1,252	5.0%
US$750 notes issued 2015 at 5.875%[4,5]	2075	**1,024**	**6.5%**	939	5.9%
US$1,200 notes issued 2016 at 6.125%[4,5]	2076	**1,637**	**7.2%**	1,502	6.6%
US$1,500 notes issued 2017 at 5.55%[4,5]	2077	**2,047**	**6.2%**	1,878	5.6%
$1,500 notes issued 2017 at 4.90%[4,5]	2077	**1,500**	**5.5%**	1,500	5.1%
		7,572		7,071	
Unamortized debt discount and issue costs		**(64)**		(64)	
		7,508		7,007	

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 loan fees and discounts.
2 The Junior subordinated notes are subordinated in right of payment to existing and future senior indebtedness or other obligations of TCPL.
3 In May 2017, Junior subordinated notes of US $1 billion converted from a fixed rate of 6.35 per cent to a floating rate that is reset quarterly to the three month LIBOR plus 2.21 per cent.
4 The Junior subordinated notes were issued to TransCanada Trust, a financing trust subsidiary wholly-owned by TCPL. While the obligations of the Trust are fully and unconditionally guaranteed by TCPL on a subordinated basis, the Trust is not consolidated in TransCanada'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.
5 The coupon rate is initially a fixed interest rate for the first ten years and converts to a floating rate thereafter.

In March 2017, TransCanada Trust (the Trust) issued US$1.5 billion of Trust Notes – Series 2017-A to third party investors with a fixed interest rate of 5.30 per cent for the first ten years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for US$1.5 billion of junior subordinated notes of TCPL at an initial fixed rate of 5.55 per cent, including a 0.25 per cent administration charge. The rate will reset commencing March 2027 until March 2047 to the then three month LIBOR plus 3.458 per cent per annum; from March 2047 until March 2077, the interest rate will reset to the then three month LIBOR plus 4.208 per cent per annum. The junior subordinated notes are redeemable at TCPL's option at any time on or after March 15, 2027 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

In May 2017, the Trust issued $1.5 billion of Trust Notes – Series 2017-B to third party investors with a fixed interest rate of 4.65 per cent for the first ten years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for $1.5 billion of junior subordinated notes of TCPL at an initial fixed rate of 4.90 per cent, including a 0.25 per cent administration charge. The rate will reset commencing May 2027 until May 2047 to the then three month Bankers' Acceptance rate plus 3.33 per cent per annum; from May 2047 until May 2077, the interest rate will reset to the thenthree month Bankers' Acceptance rate plus 4.08 per cent per annum. The junior subordinated notes are redeemable at TCPL's option at any time on or after May 18, 2027 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

In August 2016, the Trust issued US$1.2 billion of Trust Notes – Series 2016-A to third party investors at a fixed interest rate of 5.875 per cent for the first ten years, converting to a floating rate thereafter. All of the issuance proceeds of the Trust were loaned to TCPL for US$1.2 billion of junior subordinated notes of TCPL at an initial fixed rate of 6.125 per cent, including a 0.25 per cent administration charge. The rate will reset commencing August 2026 until August 2046 to the then three month LIBOR plus 4.89 per cent per annum; from August 2046 to August 2076 the interest rate will reset to the then three month LIBOR plus 5.64 per cent per annum. The junior subordinated notes are redeemable at TCPL's option at any time on or after August 15, 2026 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

Pursuant to the terms of 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) TransCanada 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.

19. NON-CONTROLLING INTERESTS

The Company's Non-controlling interests included in the Consolidated balance sheet are as follows:

at December 31 (millions of Canadian $)	2018	2017
Non-controlling interest in TC PipeLines, LP	**1,655**	1,852

The Company's Net (loss)/income attributable to non-controlling interests included in the Consolidated statement of income are as follows:

year ended December 31 (millions of Canadian $)	2018	2017	2016
Non-controlling interest in TC PipeLines, LP	**(185)**	220	215
Non-controlling interest in Portland Natural Gas Transmission System[1]	**—**	9	20
Non-controlling interest in Columbia Pipeline Partners LP[2]	**—**	9	17
	(185)	238	252

1 Non-controlling interest in 2017 for the period January 1 to May 31 when TransCanada sold its remaining interest in Portland to TC PipeLines, LP. Refer to Note 26, Acquisitions and dispositions for further information.

2 Non-controlling interest up to February 17, 2017 acquisition of all publicly held common units of Columbia Pipeline Partners LP.

TC PipeLines, LP

During 2018, the non-controlling interest in TC PipeLines, LP increased from 74.3 per cent to 74.5 per cent due to periodic issuances of common units in TC PipeLines, LP to third parties under an at-the-market issuance program. In 2017, the non-controlling interest in TC PipeLines, LP ranged between 73.2 per cent and 74.3 per cent, and in 2016, between 72.0 per cent and 73.2 per cent.

Portland Natural Gas Transmission System

On June 1, 2017, TransCanada sold its remaining 11.81 per cent directly held interest in Portland to TC PipeLines, LP and, as a result, at December 31, 2017 and 2018, non-controlling interest in Portland was nil. On January 1, 2016, TransCanada sold 49.9 per cent of Portland to TC PipeLines, LP. Refer to Note 26, Acquisitions and dispositions for further information.

Columbia Pipeline Partners LP

On July 1, 2016, TransCanada acquired Columbia, which included a 53.5 per cent non-controlling interest in Columbia Pipeline Partners LP (CPPL). On February 17, 2017, TransCanada acquired all outstanding publicly held common units of CPPL at a price of US$17.00 and a stub period distribution payment of US$0.10 per common unit for an aggregate transaction value of US$921 million. As this was a transaction between entities under common control, it was recognized in equity.

At December 31, 2016, the entire $1,073 million (US$799 million) of TransCanada's non-controlling interest in CPPL was recorded as Common units subject to rescission or redemption on the Consolidated balance sheet. The Company classified this non-controlling interest outside of equity as the potential redemption rights of the units were not within the control of the Company.

Common Units of TC PipeLines, LP Subject to Rescission

In connection with a late filing of an employee-related Form 8-K with the SEC, in March 2016, TC PipeLines, LP became ineligible to use the then effective shelf registration statement upon filing of its 2015 Annual Report. As a result, it was determined that the purchasers of the 1.6 million common units that were issued from March 8, 2016 to May 19, 2016 under the TC PipeLines, LP at-the-market issuance program may have had a rescission right for an amount equal to the purchase price paid for the units, plus statutory interest and less any distributions paid, upon the return of such units to TC PipeLines, LP within one year of purchase.

As a result, at December 31, 2016, $106 million (US$82 million) was recorded as Common units subject to rescission or redemption on the Consolidated balance sheet. The Company classified these 1.6 million common units outside equity because the potential rescission rights of the units were not within the control of the Company. At December 31, 2017, all rescission rights previously classified outside of equity had lapsed and been reclassified to equity. These rights expired one year from the date of purchase of each unit and no unitholder claimed or attempted to exercise any of these rescission rights while they remained outstanding.

20. COMMON SHARES

	Number of Shares (thousands)	Amount (millions of Canadian $)
Outstanding at January 1, 2016	702,614	12,102
Issued under public offerings[1]	156,825	7,752
Dividend reinvestment and share purchase plan	2,942	177
Exercise of options	1,683	74
Repurchase of shares	(305)	(6)
Outstanding at December 31, 2016	863,759	20,099
Dividend reinvestment and share purchase plan	12,824	790
At-the-market equity issuance program[1]	3,462	216
Exercise of options	1,331	62
Outstanding at December 31, 2017	881,376	21,167
At-the-market equity issuance program[1]	**20,050**	**1,118**
Dividend reinvestment and share purchase plan	**15,937**	**855**
Exercise of options	**734**	**34**
Outstanding at December 31, 2018	**918,097**	**23,174**

1 Net of issue costs and deferred income taxes.

Common Shares Issued and Outstanding

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

Dividend Reinvestment and Share Purchase Plan

Effective July 1, 2016, the Company re-initiated the issuance of common shares from treasury under its Dividend Reinvestment Plan (DRP) and Share Purchase Plan. Under these plans, eligible holders of common and preferred shares of TransCanada can reinvest their dividends and make optional cash payments to obtain TransCanada common shares. Under the DRP, common shares were issued from treasury at a discount of two per cent.

TransCanada Corporation At-the-Market Equity Issuance Program

In June 2017, the Company established an At-the-Market Equity Issuance 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 (TSX), the New York Stock Exchange (NYSE) or any other existing trading market for TransCanada common shares in Canada or the United States. The ATM program, which is effective for a 25-month period, is utilized as appropriate in order to manage the Company's capital structure over time. Under the original ATM program, the Company could issue up to $1.0 billion in common shares or the U.S. dollar equivalent.

In 2017, 3.5 million common shares were issued under the ATM program at an average price of $63.03 per share for proceeds of $216 million, net of approximately $2 million of related commissions and fees.

In June 2018, the Company replenished the capacity available under its existing ATM program. This allows for the issuance of additional common shares from treasury for an aggregate gross sales price of up to $1.0 billion, for a revised total of $2.0 billion or its U.S. dollar equivalent. The ATM program, as amended, is effective to July 23, 2019.

In 2018, 20 million common shares were issued under the ATM program at an average price of $56.13 per share for proceeds of $1.1 billion, net of approximately $10 million of related commissions and fees.

Common Share Public Offering and Subscription Receipts

To partially fund the Columbia acquisition, in April 2016, the Company issued 96.6 million subscription receipts at a price of $45.75 each for gross proceeds of approximately $4.4 billion. Holders of subscription receipts received one common share in exchange for each subscription receipt on July 1, 2016 upon closing of the acquisition. Holders of record at close of business on April 15, 2016 and June 30, 2016 received a cash payment per subscription receipt that was equal in amount to dividends declared on each common share. For the year ended December 31, 2016, $109 million of dividend equivalent payments on these subscription receipts were recorded as Interest expense.

In November 2016, the Company issued 60.2 million common shares at a price of $58.50 each for gross proceeds of approximately $3.5 billion. Proceeds from this offering were used to repay a portion of the US$6.9 billion acquisition bridge facilities which were used to partially fund the Columbia acquisition.

Common Shares Repurchased

In November 2015, the Company received approval from the TSX for a normal course issuer bid (NCIB) allowing it to repurchase, for cancellation, up to 21 million of its common shares representing three per cent of its then issued and outstanding common shares. Under the NCIB, which expired in November 2016, the Company purchased these common shares through the facilities of the TSX and other designated exchanges and published markets in Canada, or through off-exchange block purchases by way of private agreement.

In January 2016, the Company repurchased 305,407 of its common shares at an average price of $44.90 for a total of $14 million. These shares had a weighted average cost of $6 million with the difference of $8 million between the total price paid and the weighted average cost recorded in Additional paid-in capital.

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 higher weighted average number of shares for the diluted earnings per share calculation is due to options exercisable under TransCanada's Stock Option Plan and shares issuable under the DRP.

Weighted Average Common Shares Outstanding (millions)	**2018**	**2017**	**2016**
Basic	**902**	872	759
Diluted	**903**	874	760

Stock Options

	Number of Options (thousands)	Weighted Average Exercise Prices	Weighted Average Remaining Contractual Life (years)
Options outstanding at January 1, 2018	11,026	$51.38	
Options granted	**2,250**	**$56.89**	
Options exercised	**(734)**	**$42.65**	
Options forfeited/expired	**(138)**	**$57.23**	
Options Outstanding at December 31, 2018	**12,404**	**$52.83**	**3.6**
Options Exercisable at December 31, 2018	**8,189**	**$50.72**	**2.6**

At December 31, 2018, an additional 9,790,373 common shares were reserved for future issuance from treasury under TransCanada'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 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	2018	2017	2016
Weighted average fair value	**$5.80**	$7.22	$5.67
Expected life (years)[1]	**5.7**	5.7	5.8
Interest rate	**2.1%**	1.2%	0.7%
Volatility[2]	**16%**	18%	21%
Dividend yield	**4.2%**	3.6%	4.9%
Forfeiture rate[3]	**—**	—	5%

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.
3 On January 1, 2017, TransCanada made an election to account for forfeitures when they occur as a result of new GAAP guidance.

The amount expensed for stock options, with a corresponding increase in Additional paid-in capital, was $13 million in 2018 (2017 – $12 million; 2016 – $15 million). At December 31, 2018, unrecognized compensation costs related to non-vested stock options was $16 million. The cost is expected to be fully recognized over a three-year period.

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian $, unless otherwise noted)	2018	2017	2016
Total intrinsic value of options exercised	**10**	28	31
Fair value of options that have vested	**101**	140	126
Total options vested	**2.1 million**	2.3 million	2.1 million

As at December 31, 2018, the aggregate intrinsic value of the total options exercisable was $8 million and the total intrinsic value of options outstanding was $9 million.

Shareholder Rights Plan

TransCanada's Shareholder Rights Plan is designed to provide the Board of Directors with sufficient time to explore and develop alternatives for maximizing shareholder value in the event of a takeover offer for the Company and to encourage the fair treatment of shareholders in connection with any such offer. Attached to each common share is one right that, under certain circumstances, entitles certain holders to purchase an additional common share of the Company for half the then current market price of one common share.

21. PREFERRED SHARES

at December 31	Number of Shares Outstanding (thousands)	Current Yield	Annual Dividend Per Share	Redemption Price Per Share	Redemption and Conversion Option Date	Right to Convert Into[1,2]	2018	2017	2016
							(millions of Canadian $)[3]		
Cumulative First Preferred Shares									
Series 1	9,498	3.266%	$0.8165	$25.00	December 31, 2019	Series 2	**233**	233	233
Series 2	12,502	Floating[4]	Floating	$25.00	December 31, 2019	Series 1	**306**	306	306
Series 3	8,533	2.152%	$0.538	$25.00	June 30, 2020	Series 4	**209**	209	209
Series 4	5,467	Floating[4]	Floating	$25.00	June 30, 2020	Series 3	**134**	134	134
Series 5	12,714	2.263%	$0.56575	$25.00	January 30, 2021	Series 6	**310**	310	310
Series 6	1,286	Floating[4]	Floating	$25.00	January 30, 2021	Series 5	**32**	32	32
Series 7	24,000	4.00%	$1.00	$25.00	April 30, 2019	Series 8	**589**	589	589
Series 9	18,000	4.25%	$1.0625	$25.00	October 30, 2019	Series 10	**442**	442	442
Series 11	10,000	3.80%	$0.95	$25.00	November 30, 2020	Series 12	**244**	244	244
Series 13	20,000	5.50%	$1.375	$25.00	May 31, 2021	Series 14	**493**	493	493
Series 15	40,000	4.90%	$1.225	$25.00	May 31, 2022	Series 16	**988**	988	988
Carrying value							**3,980**	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), 4.69 per cent (Series 14) and 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), 4.69 per cent, subject to a minimum of 5.50 per cent (Series 13) and 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 3.633 per cent and for the Series 4 preferred shares is 2.993 per cent for the period starting December 31, 2018 to, but excluding, March 29, 2019. The floating quarterly dividend rate for the Series 6 preferred shares is 3.086 per cent for the period starting October 30, 2018 to, but excluding, January 30, 2019. These rates will reset each quarter going forward.

In February 2016, holders of 1,285,739 Series 5 cumulative redeemable first preferred shares exercised their option to convert to Series 6 cumulative redeemable first preferred shares.

In April 2016, the Company completed a public offering of 20 million Series 13 cumulative redeemable minimum rate reset first preferred shares at $25 per share, resulting in gross proceeds of $500 million.

In November 2016, the Company completed a public offering of 40 million Series 15 cumulative redeemable minimum rate reset first preferred shares at $25 per share, resulting in gross proceeds of $1.0 billion.

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.

TransCanada 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 TransCanada at any time other than on a designated date for $25.50 per share plus all accrued and unpaid dividends on such redemption date.

22. OTHER COMPREHENSIVE INCOME/(LOSS) AND ACCUMULATED OTHER COMPREHENSIVE LOSS

Components of OCI, including the portion attributable to non-controlling interests and related tax effects, are as follows:

year ended December 31, 2018 (millions of Canadian $)	Before Tax Amount	Income Tax Recovery/(Expense)	Net of Tax Amount
Foreign currency translation gains on net investment in foreign operations	**1,323**	**35**	**1,358**
Change in fair value of net investment hedges	**(57)**	**15**	**(42)**
Change in fair value of cash flow hedges	**(14)**	**4**	**(10)**
Reclassification to net income of gains and losses on cash flow hedges	**27**	**(6)**	**21**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**(153)**	**39**	**(114)**
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**20**	**(5)**	**15**
Other comprehensive income on equity investments	**113**	**(27)**	**86**
Other Comprehensive Income	**1,259**	**55**	**1,314**

year ended December 31, 2017 (millions of Canadian $)	Before Tax Amount	Income Tax Recovery/(Expense)	Net of Tax Amount
Foreign currency translation losses on net investment in foreign operations	(746)	(3)	(749)
Reclassification of foreign currency translation gains on disposal of foreign operations	(77)	—	(77)
Change in fair value of cash flow hedges	3	—	3
Reclassification to net income of gains and losses on cash flow hedges	(3)	1	(2)
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	(14)	3	(11)
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	21	(5)	16
Other comprehensive loss on equity investments	(141)	35	(106)
Other Comprehensive Loss	(957)	31	(926)

year ended December 31, 2016 (millions of Canadian $)	Before Tax Amount	Income Tax Recovery/(Expense)	Net of Tax Amount
Foreign currency translation gains on net investment in foreign operations	3	—	3
Change in fair value of net investment hedges	(14)	4	(10)
Change in fair value of cash flow hedges	44	(14)	30
Reclassification to net income of gains and losses on cash flow hedges	71	(29)	42
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	(38)	12	(26)
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	22	(6)	16
Other comprehensive loss on equity investments	(117)	30	(87)
Other Comprehensive Loss	(29)	(3)	(32)

The changes in AOCI by component are as follows:

	Currency Translation Adjustments	Cash Flow Hedges	Pension and Other Post-Retirement Benefit Plan Adjustments	Equity Investments	Total[1]
AOCI balance at January 1, 2016	(383)	(97)	(198)	(261)	(939)
Other comprehensive income/(loss) before reclassifications[2]	7	27	(26)	(101)	(93)
Amounts reclassified from AOCI	—	42	16	14	72
Net current period other comprehensive income/(loss)	7	69	(10)	(87)	(21)
AOCI balance at December 31, 2016	(376)	(28)	(208)	(348)	(960)
Other comprehensive (loss)/income before reclassifications[2,3]	(590)	(1)	(11)	(117)	(719)
Amounts reclassified from AOCI	(77)	(2)	16	11	(52)
Net current period other comprehensive (loss)/income	(667)	(3)	5	(106)	(771)
AOCI balance at December 31, 2017	(1,043)	(31)	(203)	(454)	(1,731)
Other comprehensive income/(loss) before reclassifications[2]	**1,150**	**(9)**	**(114)**	**72**	**1,099**
Amounts reclassified from AOCI[4,5]	**—**	**16**	**15**	**12**	**43**
Net current period other comprehensive income/(loss)	**1,150**	**7**	**(99)**	**84**	**1,142**
Reclassification of AOCI to retained earnings resulting from U.S. Tax Reform	**—**	**1**	**(12)**	**(6)**	**(17)**
AOCI balance at December 31, 2018	**107**	**(23)**	**(314)**	**(376)**	**(606)**

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.

2 In 2018, other comprehensive income before reclassifications on currency translation adjustments and cash flow hedges are net of non-controlling interest gains of $166 million (2017 – $159 million losses; 2016 – $14 million losses) and losses of $1 million (2017 – $4 million gains and 2016 – $3 million gains), respectively.

3 Other comprehensive (loss)/income before reclassification on pension and other post-retirement benefit plan adjustments includes a $27 million reduction on settlements and curtailments.

4 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 $15 million ($11 million, net of tax) at December 31, 2018. 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.

5 Amounts reclassified from AOCI on cash flow hedges and equity investments are net of non-controlling interest gains of $5 million and $2 million, respectively.

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

year ended December 31 (millions of Canadian $)	Amounts Reclassified From AOCI[1] 2018	2017	2016	Affected Line Item in the Consolidated Statement of Income
Cash flow hedges				
Commodities	**(4)**	20	(57)	Revenues (Energy)
Interest	**(18)**	(17)	(14)	Interest expense
	(22)	3	(71)	Total before tax
	6	(1)	29	Income tax expense
	(16)	2	(42)	Net of tax[1,3]
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial gains and losses	**(16)**	(15)	(22)	Plant operating costs and other[2]
Settlement charge	**(4)**	(2)	—	Plant operating costs and other[2]
	(20)	(17)	(22)	Total before tax
	5	5	6	Income tax expense
	(15)	(12)	(16)	Net of tax[1]
Equity investments				
Equity income	**(16)**	(15)	(19)	Income from equity investments
	4	4	5	Income tax expense
	(12)	(11)	(14)	Net of tax[1,3]
Currency translation adjustments				
Realization of foreign currency translation gains on disposal of foreign operations	**—**	77	—	Gain/(loss) on assets held for sale/sold
	—	—	—	Income tax expense
	—	77	—	Net of tax[1]

1 Amounts in parentheses indicate expenses to the Consolidated statement of income.

2 These AOCI components are included in the computation of net benefit cost. Refer to Note 23, Employee post-retirement benefits for further information.

3 Amounts reclassified from AOCI on cash flow hedges and equity investments are net of non-controlling interest gains of $5 million (2017 – nil , 2016 – nil) and $2 million (2017 – nil, 2016 – nil), respectively.

23. EMPLOYEE POST-RETIREMENT BENEFITS

The Company sponsors DB Plans for its employees. Pension benefits provided under the DB Plans are based on years of service and highest average earnings over three 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. Net actuarial gains or losses are amortized out of AOCI over the expected average remaining service life of employees, which is approximately nine years at December 31, 2018 (2017 and 2016 – nine years).

On December 31, 2017, the Columbia DB Plan merged with TransCanada's U.S. DB Plan. Members accruing benefits in the Columbia DB Plan as of December 31, 2017 were provided an option to either continue receiving benefits in the Columbia DB Plan or instead participate in the existing U.S. DC plan. In addition, on January 1, 2018, the Columbia other post-retirement benefit plan merged with TransCanada's U.S. other post-retirement benefit plan.

The Company also provides its employees with a savings plan in Canada, DC Plans consisting of 401(k) Plans 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 expected average remaining service life of employees, which was approximately 12 years at December 31, 2018 (2017 and 2016 – 12 years). In 2018, the Company expensed $59 million (2017 – $42 million; 2016 – $52 million) for the savings and DC Plans.

Effective April 1, 2017, the Company closed its U.S. DB Plan to non-union new entrants. As of April 1, 2017, all non-union hires participate in the existing DC plan. Non-union U.S. employees who participated in the DC Plan, had one final election opportunity to become a member of the U.S. DB Plan as of January 1, 2018.

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

year ended December 31 (millions of Canadian $)	**2018**	**2017**	**2016**
DB Plans	**103**	163	111
Other post-retirement benefit plans	**23**	7	8
Savings and DC Plans	**59**	42	52
	185	212	171

Current Canadian pension legislation allows for partial funding of solvency requirements over a number of years through letters of credit in lieu of cash contributions, up to certain limits. As such, in addition to the cash contributions noted above, the Company provided a $17 million letter of credit to the Canadian DB Plan in 2018 (2017 – $27 million; 2016 – $20 million), resulting in a total of $277 million provided to the Canadian DB Plan under letters of credit at December 31, 2018.

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2018 and the next required valuation will be as at January 1, 2019.

In December 2018, the Company recorded a settlement resulting from lump sum payments made in 2018 to certain terminated non-union vested participants in the Company's U.S. DB Plan related to voluntary cash settlement options available to these participants. The impact of the settlement was determined using assumptions consistent with those employed at December 31, 2017. The settlement reduced the Company's U.S. DB Plan's unrealized actuarial losses by $4 million which was included in OCI and resulted in a settlement charge of $4 million which was recorded in net benefit costs in 2018. Effective December 1, 2018, the plan was amended to include this unlimited lump sum payment option for certain union employees who were not previously eligible.

In 2017, as a result of settlements and curtailments that occurred upon the completion of the U.S. Northeast power generation asset sales, interim remeasurements were performed on TransCanada's U.S. DB Plan and other post-retirement benefit plans using a weighted average discount rate of 4.10 per cent. All other assumptions were consistent with those employed at December 31, 2016. The impact of these remeasurements reduced the U.S. DB Plan's unrealized actuarial losses by $3 million, which was included in OCI, and resulted in a settlement charge of$2 million which was recorded in net benefit cost in 2017. These remeasurements had no impact on the other post-retirement benefit plan's unrealized actuarial losses.

Also in 2017, lump sum payouts exceeded service and interest costs for the Columbia DB Plan. As a result, an interim remeasurement was performed on the Columbia DB Plan at September 30, 2017 using a discount rate of 3.70 per cent. The interim remeasurement of the Columbia DB Plan increased the Company's unrealized actuarial gains by $16 million, of which $14 million was recorded in Regulatory assets and$2 million was recorded in OCI. All other assumptions were consistent with those employed at December 31, 2016.

The Company's funded status at December 31 is comprised of the following:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	2018	2017	2018	2017
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**3,646**	3,456	**375**	372
Service cost	**121**	113	**4**	4
Interest cost	**134**	135	**14**	14
Employee contributions	**5**	5	**—**	3
Benefits paid	**(177)**	(166)	**(23)**	(19)
Actuarial (gain)/loss	**(92)**	253	**43**	19
Curtailment	**—**	(14)	**—**	(2)
Settlement	**(71)**	(66)	**—**	—
Foreign exchange rate changes	**87**	(70)	**17**	(16)
Benefit obligation – end of year	**3,653**	3,646	**430**	375
Change in Plan Assets				
Plan assets at fair value – beginning of year	**3,451**	3,208	**365**	354
Actual return on plan assets	**(73)**	358	**(15)**	45
Employer contributions[2]	**103**	163	**23**	7
Employee contributions	**5**	5	**—**	3
Benefits paid	**(176)**	(166)	**(27)**	(19)
Settlement	**(71)**	(57)	**—**	—
Foreign exchange rate changes	**82**	(60)	**30**	(25)
Plan assets at fair value – end of year	**3,321**	3,451	**376**	365
Funded Status – Plan Deficit	**(332)**	(195)	**(54)**	(10)

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 $17 million letter of credit provided to the Canadian DB Plan for funding purposes (2017 – $27 million).

The amounts recognized in the Company's Consolidated balance sheet for its DB Plans and other post-retirement benefits plans are as follows:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	2018	2017	2018	2017
Intangible and other assets (Note 12)	**—**	—	**192**	193
Accounts payable and other	**(1)**	(1)	**(8)**	(8)
Other long-term liabilities (Note 15)	**(331)**	(194)	**(238)**	(195)
	(332)	(195)	**(54)**	(10)

Included in the above benefit obligation and fair value of plan assets were the following amounts for plans that are not fully funded:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	2018	2017	2018	2017
Projected benefit obligation[1]	**(3,653)**	(3,646)	**(246)**	(203)
Plan assets at fair value	**3,321**	3,451	**—**	—
Funded Status – Plan Deficit	**(332)**	(195)	**(246)**	(203)

1 The projected benefit obligation for the pension benefit plans differ 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 is as follows:

at December 31 (millions of Canadian $)	2018	2017
Accumulated benefit obligation	**(3,347)**	(3,372)
Plan assets at fair value	**3,321**	3,451
Funded Status	**(26)**	79

Included in the above accumulated benefit obligation and fair value of plan assets are the following amounts in respect of plans that are not fully funded.

at December 31 (millions of Canadian $)	2018	2017
Accumulated benefit obligation	**(3,347)**	(944)
Plan assets at fair value	**3,321**	925
Funded Status – Plan Deficit	**(26)**	(19)

The Company pension plans' weighted average asset allocations and target allocations by asset category were as follows:

	Percentage of Plan Assets		Target Allocations
at December 31	2018	2017	2018
Debt securities	**33%**	30%	**25% to 45%**
Equity securities	**56%**	64%	**40% to 70%**
Alternatives	**11%**	6%	**5% to 15%**
	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 $)	2018	2017	2018	2017
Debt securities	**8**	7	**0.3%**	0.2%
Equity securities	**7**	3	**0.2%**	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 further information on the fair value hierarchy, refer to Note 24, 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 $)	2018	2017	2018	2017	2018	2017	2018	2017	2018	2017
Asset Category										
Cash and Cash Equivalents	**48**	44	**—**	17	**—**	—	**48**	61	**1**	2
Equity Securities:										
Canadian	**355**	410	**138**	151	**—**	—	**493**	561	**13**	15
U.S.	**460**	543	**116**	354	**—**	—	**576**	897	**16**	24
International	**40**	45	**281**	322	**—**	—	**321**	367	**9**	10
Global	**116**	—	**268**	301	**—**	—	**384**	301	**10**	8
Emerging	**8**	8	**138**	147	**—**	—	**146**	155	**4**	4
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**186**	193	**—**	—	**186**	193	**5**	5
Provincial	**—**	—	**198**	194	**—**	—	**198**	194	**5**	5
Municipal	**—**	—	**8**	8	**—**	—	**8**	8	**1**	—
Corporate	**—**	—	**112**	122	**—**	—	**112**	122	**3**	3
U.S. Bonds:										
Federal	**350**	—	**—**	244	**—**	—	**350**	244	**9**	6
State	**—**	—	**—**	41	**—**	—	**—**	41	**—**	1
Municipal	**—**	—	**—**	4	**—**	—	**—**	4	**—**	—
Corporate	**145**	—	**51**	234	**—**	—	**196**	234	**5**	6
International:										
Government	**6**	—	**4**	4	**—**	—	**10**	4	**1**	—
Corporate	**19**	—	**18**	5	**—**	—	**37**	5	**1**	—
Mortgage backed	**128**	—	**—**	73	**—**	—	**128**	73	**3**	2
Other Investments:										
Real estate	**—**	—	**—**	—	**196**	140	**196**	140	**5**	4
Infrastructure	**—**	—	**—**	—	**163**	70	**163**	70	**4**	2
Private equity funds	**—**	—	**—**	—	**3**	6	**3**	6	**1**	—
Funds held on deposit	**142**	136	**—**	—	**—**	—	**142**	136	**4**	3
	1,817	1,186	**1,518**	2,414	**362**	216	**3,697**	3,816	**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, 2016	199
Purchases and sales	11
Realized and unrealized gains	6
Balance at December 31, 2017	216
Purchases and sales	**127**
Realized and unrealized gains	**19**
Balance at December 31, 2018	**362**

The Company's expected funding contributions in 2019 are approximately $113 million for the DB Plans, approximately $7 million for the other post-retirement benefit plans and approximately $61 million for the savings plan and DC Plans. The Company expects to provide an additional estimated $17 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
2019	190	24
2020	193	23
2021	198	23
2022	203	23
2023	207	23
2024 to 2028	1,081	114

The rate used to discount pension and other post-retirement benefit plan obligations was developed based on a yield curve of corporate AA bond yields at December 31, 2018. 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 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:

	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
at December 31	**2018**	**2017**	**2018**	**2017**
Discount rate	**3.90%**	3.60%	**4.10%**	3.70%
Rate of compensation increase	**3.00%**	3.00%	**—**	—

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan costs were as follows:

	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
year ended December 31	**2018**	**2017**	**2016**	**2018**	**2017**	**2016**
Discount rate	**3.60%**	3.95%	4.20%	**3.70%**	4.15%	4.30%
Expected long-term rate of return on plan assets	**6.70%**	6.50%	6.70%	**4.00%**	6.05%	5.95%
Rate of compensation increase	**3.00%**	1.20%	0.80%	**—**	—	—

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 six per cent weighted average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2019 measurement purposes. The rate was assumed to decrease gradually to 4.50% by 2028 and remain at this level thereafter. A one per cent change in assumed health care cost trend rates would have the following effects:

(millions of Canadian $)	Increase	Decrease
Effect on total of service and interest cost components	1	(1)
Effect on post-retirement benefit obligation	25	(21)

The net benefit cost recognized for the Company's pension benefit plans and other post-retirement benefit plans is as follows:

at December 31	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
(millions of Canadian $)	2018	2017	2016	2018	2017	2016
Service cost[1]	**121**	108	107	**4**	4	3
Other components of net benefit cost[1]						
Interest cost	**134**	122	127	**14**	14	13
Expected return on plan assets	**(221)**	(178)	(175)	**(16)**	(21)	(11)
Amortization of actuarial loss	**15**	14	20	**1**	1	2
Amortization of regulatory asset	**18**	37	27	**—**	1	1
Amortization of transitional obligation related to regulated business	**—**	—	—	**—**	—	2
Settlement charge – regulatory asset	**—**	2	—	**—**	—	—
Settlement charge – AOCI	**4**	2	—	**—**	—	—
	(50)	(1)	(1)	**(1)**	(5)	7
Net Benefit Cost Recognized	**71**	107	106	**3**	(1)	10

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	2018		2017		2016	
(millions of Canadian $)	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Net loss	**364**	**53**	273	11	270	21

The estimated net loss for the DB Plans and for the other post-retirement benefit plans that will be amortized from AOCI into net periodic benefit cost in 2019 is $12 million and $2 million, respectively.

Pre-tax amounts recognized in OCI were as follows:

at December 31	2018		2017		2016	
(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	**(15)**	**(1)**	(18)	(1)	(20)	(2)
Curtailment	**—**	**—**	(14)	(2)	—	—
Settlement	**(4)**	**—**	(11)	—	—	—
Funded status adjustment	**110**	**43**	46	(7)	43	(5)
	91	**42**	3	(10)	23	(7)

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TransCanada 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 earnings, cash flow and shareholder value.

Risk management strategies, policies and limits are designed to ensure TransCanada'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 established by the Company's Board of Directors, implemented by senior management and monitored by the Company's risk management and internal audit 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-term 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 and the value of the financial instruments it holds. 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 the exposure to market risk may consist of 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 exposure to commodity price risk in the Company's non-regulated businesses:

- In the Company's power generation business, TransCanada manages the exposure to fluctuating commodity prices through long-term contracts and hedging activities including selling and purchasing power and natural gas in forward markets
- In the Company's non-regulated natural gas storage business, TransCanada'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
- In the Company's liquids marketing business, TransCanada enters into pipeline and storage terminal capacity contracts. TransCanada fixes a portion of its exposure on these contracts by entering into derivative instruments to manage its variable price fluctuations that arise from physical liquids transactions.

The Company's exposure to electricity price risk has been greatly reduced following the sales of its U.S. Northeast power generation assets in 2017 and its U.S. Northeast power retail contracts on March 1, 2018 as well as the continued wind-down of its remaining U.S. Power marketing contracts.

Interest rate risk

TransCanada utilizes short-term and long-term debt to finance its operations which exposes the Company to interest rate risk. TransCanada typically pays fixed rates of interest on its long-term debt and floating rates on its commercial paper programs and amounts drawn on its credit facilities. A small portion of TransCanada's long-term debt is at floating interest rates. In addition, the Company is exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. The Company manages its interest rate risk using a combination of interest rate swaps and option derivatives.

Foreign exchange risk

TransCanada generates revenues and incurs expenses that are denominated in currencies other than Canadian dollars. As a result, the Company's earnings and cash flows are exposed to currency fluctuations.

A portion of TransCanada's businesses generate earnings in U.S. dollars, but since its financial results are reported 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 hedged on a rolling one-year basis using foreign exchange derivatives, but the exposure remains beyond that period.

Net investment hedges

The Company hedges its net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency swaps and foreign exchange options.

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

at December 31 (millions of Canadian $, unless otherwise noted)	2018 Fair Value[1,2]	2018 Notional Amount	2017 Fair Value[1,2]	2017 Notional Amount
U.S. dollar cross-currency interest rate swaps (maturing 2019)[3]	**(43)**	**US 300**	(199)	US 1,200
U.S. dollar foreign exchange options (maturing 2019 to 2020)	**(47)**	**US 2,500**	5	US 500
	(90)	**US 2,800**	(194)	US 1,700

1 Fair value equals carrying value.
2 No amounts have been excluded from the assessment of hedge effectiveness.
3 In 2018, Net income includes net realized gains of $2 million (2017 – gains of $4 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)	2018	2017
Notional amount	**31,000 (US 22,700)**	25,400 (US 20,200)
Fair value	**31,700 (US 23,200)**	28,900 (US 23,100)

Counterparty Credit Risk

TransCanada's maximum counterparty credit exposure with respect to financial instruments at December 31,2018, without taking into account security held, consisted of cash and cash equivalents, accounts receivable, available-for-sale assets, derivative assets and a loan receivable.

Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of the related contract or agreement with the Company.

The Company manages its exposure to this potential loss by dealing with creditworthy counterparties, obtaining financial assurances such as guarantees, letters of credit or cash where considered necessary, and setting limits on the amount TransCanada can transact with any one counterparty. There is no guarantee that these techniques will protect the Company from material losses.

The Company monitors its counterparties and regularly reviews its accounts receivable. The Company records an allowance for doubtful accounts as necessary using the specific identification method. At December 31, 2018 and 2017, there were no significant amounts past due or impaired, no significant credit risk concentration and no significant credit losses during the year.

TransCanada has significant credit and performance exposures to financial institutions as 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, intangible and other assets, notes payable, accounts payable and other, 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 and would also be classified in Level II of the fair value hierarchy.

Credit risk has been taken into consideration when calculating the fair value of non-derivative financial instruments.

Balance Sheet Presentation of Non-Derivative Financial Instruments

The following table details the fair value of non-derivative financial instruments, excluding those where carrying amounts approximate fair value, and would be classified in Level II of the fair value hierarchy:

at December 31 (millions of Canadian $)	2018 Carrying Amount	2018 Fair Value	2017 Carrying Amount	2017 Fair Value
Long-term debt, including current portion[1,2] (Note 17)	**(39,971)**	**(42,284)**	(34,741)	(40,180)
Junior subordinated notes (Note 18)	**(7,508)**	**(6,665)**	(7,007)	(7,233)
	(47,479)	**(48,949)**	(41,748)	(47,413)

1 Long-term debt is recorded at amortized cost, except for US$750 million (2017 – US$1.1 billion) that is attributed to hedged risk and recorded at fair value.

2 Net income in 2018 included unrealized losses of $2 million (2017 – gains of $4 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$750 million of long-term debt at December 31, 2018 (2017 – US$1.1 billion). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Available-for-Sale Assets Summary

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

at December 31 (millions of Canadian $)	2018 LMCI Restricted Investments	2018 Other Restricted Investments[1]	2017 LMCI Restricted Investments	2017 Other Restricted Investments[1]
Fair value of fixed income securities[2]				
Fixed income securities (maturing within 1 year)	**—**	**22**	—	23
Fixed income securities (maturing within 1-5 years)	**—**	**110**	—	107
Fixed income securities (maturing within 5-10 years)	**140**	**—**	14	—
Fixed income securities (maturing after 10 years)	**952**	**—**	790	—
	1,092	**132**	804	130

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.

year ended December 31 (millions of Canadian $)	2018 LMCI restricted investments[1]	2018 Other restricted investments	2017 LMCI restricted investments[1]	2017 Other restricted investments	2016 LMCI restricted investments[1]	2016 Other restricted investments
Net unrealized gains/(losses)	**11**	**—**	(3)	1	(28)	(1)
Net realized losses[2]	**(4)**	**—**	(1)	—	—	—

1 Gains and losses arising from changes in the fair value of LMCI restricted investments impact the subsequent amounts to be collected through tolls to cover future pipeline abandonment costs. As a result, the Company records these gains and losses as regulatory assets or liabilities.

2 The realized gains and losses on the sale of LMCI restricted investment securities 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 a market approach. The market approach bases the fair value measures on a comparable transaction using quoted market prices, or in the absence of quoted market prices, third-party broker quotes or other valuation techniques. 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, can 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 as atDecember 31, 2018 is as follows:

at December 31, 2018 (millions of Canadian $)	Cash Flow Hedges	Fair Value Hedges	Net Investment Hedges	Held for Trading	Total Fair Value of Derivative Instruments[1]
Other current assets (Note 7)					
Commodities[2]	1	—	—	716	717
Foreign exchange	—	—	16	1	17
Interest rate	3	—	—	—	3
	4	—	16	717	737
Intangible and other assets (Note 12)					
Commodities[2]	1	—	—	50	51
Foreign exchange	—	—	1	—	1
Interest rate	8	1	—	—	9
	9	1	1	50	61
Total Derivative Assets	13	1	17	767	798
Accounts payable and other (Note 14)					
Commodities[2]	(4)	—	—	(622)	(626)
Foreign exchange	—	—	(105)	(188)	(293)
Interest rate	—	(3)	—	—	(3)
	(4)	(3)	(105)	(810)	(922)
Other long-term liabilities (Note 15)					
Commodities[2]	—	—	—	(28)	(28)
Foreign exchange	—	—	(2)	—	(2)
Interest rate	(11)	(1)	—	—	(12)
	(11)	(1)	(2)	(28)	(42)
Total Derivative Liabilities	(15)	(4)	(107)	(838)	(964)
Total Derivatives	(2)	(3)	(90)	(71)	(166)

1 Fair value equals carrying value.
2 Includes purchases and sales of power, natural gas and liquids.

The balance sheet classification of the fair value of derivative instruments as atDecember 31, 2017 is as follows:

at December 31, 2017 (millions of Canadian $)	Cash Flow Hedges	Fair Value Hedges	Net Investment Hedges	Held for Trading	Total Fair Value of Derivative Instruments[1]
Other current assets (Note 7)					
Commodities[2]	1	—	—	249	250
Foreign exchange	—	—	8	70	78
Interest rate	3	—	—	1	4
	4	—	8	320	332
Intangible and other assets (Note 12)					
Commodities[2]	—	—	—	69	69
Interest rate	4	—	—	—	4
	4	—	—	69	73
Total Derivative Assets	8	—	8	389	405
Accounts payable and other (Note 14)					
Commodities[2]	(6)	—	—	(208)	(214)
Foreign exchange	—	—	(159)	(10)	(169)
Interest rate	—	(4)	—	—	(4)
	(6)	(4)	(159)	(218)	(387)
Other long-term liabilities (Note 15)					
Commodities[2]	(2)	—	—	(26)	(28)
Foreign exchange	—	—	(43)	—	(43)
Interest rate	—	(1)	—	—	(1)
	(2)	(1)	(43)	(26)	(72)
Total Derivative Liabilities	(8)	(5)	(202)	(244)	(459)
Total Derivatives	—	(5)	(194)	145	(54)

1 Fair value equals carrying value.
2 Includes purchases and sales of power, natural gas and liquids.

The majority of derivative instruments held for trading have been entered into for risk management purposes and all are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

Derivatives in fair value hedging relationships

The following table details amounts recorded on the Consolidated balance sheet in relation to cumulative adjustments for fair value hedges included in the carrying amount of the hedged liabilities:

at December 31	Carrying amount		Fair value hedging adjustments[1]	
(millions of Canadian $)	2018	2017	2018	2017
Current portion of long-term debt	**(748)**	(688)	**3**	1
Long-term debt	**(273)**	(685)	**—**	4
	(1,021)	(1,373)	**3**	5

1 At December 31, 2018 and 2017, adjustments for discontinued hedging relationships included in these balances were nil.

Notional and Maturity Summary

The maturity and notional amount or quantity outstanding related to the Company's derivative instruments excluding hedges of the net investment in foreign operations is as follows:

at December 31, 2018	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Purchases[1]	**23,865**	**44**	**59**	**—**	**—**
Sales[1]	**17,689**	**56**	**79**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**3,862**	**1,650**
Maturity dates	**2019-2023**	**2019-2027**	**2019**	**2019**	**2019-2030**

1 Volumes for power, natural gas and liquids derivatives are in GWh, Bcf and MMBbls respectively.

at December 31, 2017	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Purchases[1]	66,132	133	6	—	—
Sales[1]	42,836	135	7	—	—
Millions of U.S. dollars	—	—	—	2,931	2,300
Millions of Mexican pesos	—	—	—	100	—
Maturity dates	2018-2022	2018-2021	2018	2018	2018-2022

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 $)	2018	2017	2016
Derivative instruments held for trading[1]			
Amount of unrealized gains/(losses) in the year			
Commodities[2]	**28**	62	123
Foreign exchange	**(248)**	88	25
Interest rate	**—**	(1)	—
Amount of realized gains/(losses) in the year			
Commodities	**351**	(107)	(204)
Foreign exchange	**(24)**	18	62
Interest rate	**—**	1	—
Derivative instruments in hedging relationships			
Amount of realized (losses)/gains in the year			
Commodities	**(1)**	23	(167)
Foreign exchange	**—**	5	(101)
Interest rate	**(1)**	1	4

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 interest rate and foreign exchange held-for-trading derivative instruments are included on a net basis in Interest expense and Interest income and other, respectively.

2 In 2018 and 2017, 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 (2016 – net loss of $42 million).

Derivatives in cash flow hedging relationships

The components of OCI (Note 22) related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests are as follows:

year ended December 31 (millions of Canadian $, pre-tax)	2018	2017	2016
Change in fair value of derivative instruments recognized in OCI[1]			
Commodities	**(1)**	(1)	39
Interest rate	**(13)**	4	5
	(14)	3	44

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 on the Consolidated statement of income in which the effects of fair value or cash flow hedging relationships are recorded.

year ended December 31	Revenues (Energy)			Interest Expense		
(millions of Canadian $)	2018	2017	2016	2018	2017	2016
Total Amount Presented in the Consolidated Statement of Income	**2,124**	3,593	4,206	**(2,265)**	(2,069)	(1,998)
Fair Value Hedges						
Interest rate contracts						
Hedged items	**—**	—	—	**(71)**	(74)	(74)
Derivatives designated as hedging instruments	**—**	—	—	**(4)**	1	8
Cash Flow Hedges						
Reclassification of gains/(losses) on derivative instruments from AOCI to net income[1,2]						
Interest rate contracts	**—**	—	—	**22**	17	14
Commodity contracts	**5**	(20)	57	**—**	—	—

1 Refer to Note 22, 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.

2 There are no amounts recognized in earnings that were excluded from effectiveness testing.

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. TransCanada 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 in the Consolidated balance sheet. The following table shows 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 as at December 31, 2018:

at December 31, 2018 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative – Asset			
Commodities	**768**	**(626)**	**142**
Foreign exchange	**18**	**(18)**	**—**
Interest rate	**12**	**(4)**	**8**
	798	**(648)**	**150**
Derivative – Liability			
Commodities	**(654)**	**626**	**(28)**
Foreign exchange	**(295)**	**18**	**(277)**
Interest rate	**(15)**	**4**	**(11)**
	(964)	**648**	**(316)**

1 Amounts available for offset do not include cash collateral pledged or received.

The following table shows 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 as at December 31, 2017:

at December 31, 2017 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative – Asset			
Commodities	319	(198)	121
Foreign exchange	78	(56)	22
Interest rate	8	(1)	7
	405	(255)	150
Derivative – Liability			
Commodities	(242)	198	(44)
Foreign exchange	(212)	56	(156)
Interest rate	(5)	1	(4)
	(459)	255	(204)

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 $143 million and letters of credit of $22 million (2017 – $165 million and $30 million) to its counterparties. At December 31, 2018, the Company held nil in cash collateral and $1 million in letters of credit (2017 – nil and $3 million) 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, 2018, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $6 million (2017 – $2 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, 2018, the Company would have been required to provide collateral of $6 million (2017 – $2 million) to its counterparties. 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 bank lines 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	Valuation based on the extrapolation of inputs, other than quoted prices included within Level I, for which all significant inputs are observable directly or indirectly. Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers. 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. Transfers between Level I and Level II would occur when there is a change in market circumstances.
Level III	Valuation of assets and liabilities are measured using a market approach based on extrapolation of inputs that are unobservable or where observable data does not support a significant portion of the derivative's fair value. This category 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. Valuation of options is based on the Black-Scholes pricing model. Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which significant inputs are considered to be observable. As contracts near maturity and observable market data becomes available, they are transferred out of Level III and into Level II.

The fair value of the Company's derivative assets and liabilities measured on a recurring basis, including both current and non-current portions for 2018, are categorized as follows:

at December 31, 2018 (millions of Canadian $)	Quoted Prices in Active Markets (Level I)[1]	Significant Other Observable Inputs (Level II)[1]	Significant Unobservable Inputs (Level III)[1]	Total
Derivative Instrument Assets:				
Commodities	**581**	**187**	**—**	**768**
Foreign exchange	**—**	**18**	**—**	**18**
Interest rate	**—**	**12**	**—**	**12**
Derivative Instrument Liabilities:				
Commodities	**(555)**	**(95)**	**(4)**	**(654)**
Foreign exchange	**—**	**(295)**	**—**	**(295)**
Interest rate	**—**	**(15)**	**—**	**(15)**
	26	**(188)**	**(4)**	**(166)**

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2018 .

The fair value of the Company's derivative assets and liabilities measured on a recurring basis, including both current and non-current portions for 2017, are categorized as follows:

at December 31, 2017 (millions of Canadian $)	Quoted Prices in Active Markets (Level I)[1]	Significant Other Observable Inputs (Level II)[1]	Significant Unobservable Inputs (Level III)[1]	Total
Derivative Instrument Assets:				
Commodities	21	283	15	319
Foreign exchange	—	78	—	78
Interest rate	—	8	—	8
Derivative Instrument Liabilities:				
Commodities	(27)	(193)	(22)	(242)
Foreign exchange	—	(212)	—	(212)
Interest rate	—	(5)	—	(5)
	(6)	(41)	(7)	(54)

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2017 .

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)	2018	2017
Balance at beginning of year	**(7)**	16
Transfers out of Level III	**5**	(19)
Total gains/(losses) included in Net income	**8**	(17)
Settlements	**(9)**	18
Sales	**—**	(5)
Foreign exchange	**(1)**	—
Balance at end of year[1]	**(4)**	(7)

1 Revenues include unrealized losses of $5 million attributed to derivatives in the Level III category that were still held at December 31, 2018 (2017 – unrealized losses of $7 million).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $2 million decrease or increase, respectively, in the fair value of outstanding derivative instruments included in Level III as at December 31, 2018.

25. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian $)	2018	2017	2016
Increase in Accounts receivable	**(69)**	(576)	(482)
Increase in Inventories	**(49)**	(38)	(87)
Decrease/(increase) in Assets held for sale	**—**	14	(13)
Decrease in Other current assets	**45**	189	328
(Decrease)/increase in Accounts payable and other	**(70)**	151	424
Increase in Accrued interest	**41**	12	62
(Decrease)/increase in Liabilities related to assets held for sale	**—**	(25)	16
(Increase)/decrease in Operating Working Capital	**(102)**	(273)	248

26. ACQUISITIONS AND DISPOSITIONS

U.S. Natural Gas Pipelines

Iroquois Gas Transmission System and Portland Natural Gas Transmission System

On June 1, 2017, TransCanada closed the sale of 49.34 per cent of its 50 per cent interest in Iroquois, along with an option to sell the remaining 0.66 per cent at a later date, to TC PipeLines, LP. At the same time, TransCanada closed the sale of its remaining 11.81 per cent interest in Portland to TC PipeLines, LP. Proceeds from these transactions were US$765 million, before post-closing adjustments, and were comprised of US$597 million in cash and US$168 million representing a proportionate share of Iroquois and Portland debt.

In January 2016, TransCanada closed the sale of a 49.9 per cent interest in Portland to TC PipeLines, LP for an aggregate purchase price of US$223 million. Proceeds were comprised of US$188 million in cash and the assumption of US$35 million of a proportional share of Portland debt.

In March 2016, TransCanada acquired a 4.87 per cent interest in Iroquois for an aggregate purchase price of US$54 million, increasing TransCanada's interest in Iroquois to 49.35 per cent. On May 1, 2016, the Company acquired an additional 0.65 per cent interest for an aggregate purchase price of US$7 million, further increasing TransCanada's interest in Iroquois to 50 per cent.

Acquisition of Columbia

On July 1, 2016, TransCanada acquired 100 per cent ownership of Columbia for a purchase price of US$10.3 billion in cash, based on US$25.50 per share for all of Columbia's outstanding common shares as well as all outstanding restricted and performance stock units. The acquisition was financed through proceeds of approximately $4.4 billion from the sale of subscription receipts, draws on acquisition bridge facilities in the aggregate amount of US$6.9 billion and existing cash on hand. The sale of the subscription receipts was completed on April 1, 2016 through a public offering and, upon closing of the acquisition, were exchanged into approximately 96.6 million common shares of TransCanada. Refer to Note 20, Common shares for further information on the subscription receipts.

At the date of acquisition, Columbia operated a portfolio of approximately 24,500 km (15,200 miles) of regulated natural gas pipelines, 285 Bcf of natural gas storage facilities and midstream and other assets in various regions in the U.S. TransCanada acquired Columbia to expand the Company's natural gas business in the U.S. market, positioning the Company for additional long-term growth opportunities.

The goodwill arising from the acquisition principally reflects the opportunities to expand the Company's U.S. Natural Gas Pipelines segment and to gain a stronger competitive position in the North American natural gas business. The goodwill resulting from the acquisition is not deductible for income tax purposes. The acquisition was accounted for as a business combination using the acquisition method where the acquired tangible and intangible assets and assumed liabilities were recorded at their estimated fair values at the date of acquisition. The purchase price equation reflects management's estimate of the fair value of Columbia's assets and liabilities as at July 1, 2016.

(millions of $)	July 1, 2016 U.S.	Canadian[1]
Purchase Price Consideration	**10,294**	**13,392**
Fair Value		
Current assets	658	856
Plant, property and equipment	7,560	9,835
Equity investments	441	574
Regulatory assets	190	248
Intangible and other assets	135	175
Current liabilities	(597)	(777)
Regulatory liabilities	(294)	(383)
Other long-term liabilities	(144)	(187)
Deferred income tax liabilities	(1,613)	(2,098)
Long-term debt	(2,981)	(3,878)
Non-controlling interests	(808)	(1,051)
Fair Value of Net Assets Acquired	**2,547**	**3,314**
Goodwill	**7,747**	**10,078**

1 At July 1, 2016 exchange rate of $1.30.

The fair values of current assets including cash and cash equivalents, accounts receivable, and inventories and the fair values of current liabilities including notes payable and accrued interest approximated their carrying values due to the short-term nature of these items. Certain acquisition-related working capital items resulted in an adjustment to accounts payable.

Columbia's natural gas pipelines are subject to FERC regulations and, as a result, their rate bases are expected to be recovered with a reasonable rate of return over the life of the assets. These assets, as well as related regulatory assets and liabilities, had fair values equal to their carrying values on acquisition. The fair value of mineral rights included in Columbia's plant, property and equipment was determined using a discounted cash flow approach which resulted in a fair value increase of $241 million (US$185 million). On acquisition date, the fair value of base gas included in Columbia's plant, property and equipment was determined by using a quoted market price multiplied by the estimated volume of base gas in place which resulted in a fair value increase of $840 million (US$646 million).

In second quarter 2017, the Company completed its procedures over measuring the volume of base gas acquired and, as a result, decreased its fair value by $116 million (US$90 million). This impacted the purchase price equation by decreasing property, plant and equipment by$116 million (US$90 million), decreasing deferred income tax liabilities by $45 million (US$35 million) and increasing goodwill by $71 million (US$55 million) to a total of US$7,802 million (2016 – US$7,747 million) at December 31, 2017. This adjustment did not impact the Company's net income.

The fair value of Columbia's long-term debt was estimated using an income approach based on observable market rates for similar debt instruments from external data service providers. This resulted in a fair value increase of $300 million (US$231 million).

The following table summarizes the acquisition date fair value of Columbia's debt acquired by TransCanada.

(millions of $)	Maturity Date	Type	Fair Value	Interest Rate
COLUMBIA PIPELINE GROUP, INC.				
	June 2018	Senior Unsecured Notes (US$500)	US$506	2.45%
	June 2020	Senior Unsecured Notes (US$750)	US$779	3.30%
	June 2025	Senior Unsecured Notes (US$1,000)	US$1,092	4.50%
	June 2045	Senior Unsecured Notes (US$500)	US$604	5.80%
			US$2,981	

The fair values of Columbia's DB plan and other post-retirement benefit plans were based on an actuarial valuation of the funded status of the plans as of the acquisition date which resulted in an increase of $15 million (US$12 million) and $5 million (US$4 million) to Regulatory assets and Other long-term liabilities, respectively, and a decrease of $14 million (US$11 million) and $2 million (US$2 million) to Intangible and other assets and Regulatory liabilities, respectively.

Temporary differences created as a result of the fair value changes described above resulted in deferred income tax assets and liabilities that were recorded at the Company's then U.S. effective tax rate of 39 per cent.

The fair value of Columbia's non-controlling interests was based on the approximately 53.8 million CPPL common units outstanding to the public as of June 30, 2016, and valued at the June 30, 2016 closing price of US$15.00 per common unit. On February 17, 2017, TransCanada acquired all outstanding publicly held common units of CPPL. Refer to Note 19, Non-controlling interests, for further information.

In 2016, acquisition expenses of approximately $36 million were included in Plant operating costs and other in the Consolidated statement of income.

Upon completion of the acquisition, the Company began consolidating Columbia. Columbia's significant accounting policies were consistent with TransCanada's and continued to be applied. Columbia contributed $929 million to the Company's Revenues and $132 million to the Company's net income from July 1, 2016 to December 31, 2016.

The following supplemental pro forma consolidated financial information of the Company for the years ended December 31, 2016 and 2015 includes the results of operations for Columbia as if the acquisition had been completed on January 1, 2015.

year ended December 31		
(millions of Canadian $)	**2016**	**2015**
Revenues	**13,404**	13,007
Net Income/(Loss)	**627**	(820)
Net Income/(Loss) Attributable to Common Shares	**234**	(971)

Energy

Cartier Wind

On October 24, 2018, the Company completed the sale of its 62 per cent interest in the Cartier Wind power facilities to Innergex Renewable Energy Inc for proceeds of $630 million, before post-closing adjustments. As a result, the Company recorded a gain on sale of $170 million ($143 million after tax) which is included in Gain/(loss) on assets held for sale/sold in the Consolidated statement of income.

Ontario Solar Assets

On December 19, 2017, the Company completed the sale of its Ontario solar assets to a third party for proceeds of $541 million, before post-closing adjustments. As a result, the Company recorded a gain on sale of $127 million ($136 million after tax) which is included in Gain/(loss) on assets held for sale/sold in the Consolidated statement of income.

U.S. Northeast Power Assets

In 2018, upon finalizing its 2017 annual tax return for its U.S. operations, the Company recorded a $27 million income tax recovery related to the sale of its U.S. Northeast power generation assets.

On April 19, 2017, the Company completed the sale of TC Hydro for proceeds of approximately US$1.07 billion, before post-closing adjustments. As a result, in 2017 the Company recorded a gain on sale of $715 million ($440 million after tax) including the impact of $5 million of foreign currency translation gains which were reclassified from AOCI to net income.

On June 2, 2017, TransCanada completed the sale of Ravenswood, Ironwood, Kibby Wind and Ocean State Power for proceeds of approximately US$2.029 billion, before post-closing adjustments. In 2016, the Company recorded a loss of $829 million ($863 million after tax) which included the impact of $70 million of foreign currency translation gains that were reclassified from AOCI to net income on close. The Company recorded an additional loss on sale of $211 million ($167 million after tax) in 2017 which included $2 million in foreign currency translation gains. This additional loss primarily related to adjustments to the purchase price and repair costs for an unplanned outage at Ravenswood prior to close of the sale.

Gains and losses from these sales are included in Gain/(loss) on assets held for sale/sold in the Consolidated statement of income. The proceeds received from the sale of the U.S. Northeast Power assets were used to repay the outstanding balances on the Company's acquisition bridge facilities that partially funded the acquisition of Columbia.

Ironwood

In February 2016, TransCanada acquired the Ironwood natural gas fired, combined cycle power plant forUS$653 million in cash after post-closing adjustments. The evaluation of assigned fair value of acquired assets and liabilities did not result in the recognition of goodwill. The Company began consolidating Ironwood as of the date of acquisition which did not have a material impact on the Revenues and Net income of the Company. In addition, the pro forma incremental impact of Ironwood on the Company's Revenues and Net income from the date of acquisition to the date of sale was not material.

27. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Operating leases

Future annual payments under the Company's operating leases for various premises, services and equipment, net of sublease receipts, are approximately as follows:

year ended December 31 (millions of Canadian $)	Minimum Lease Payments	Amounts Recoverable under Subleases	Net Payments
2019	81	7	74
2020	78	7	71
2021	76	4	72
2022	69	3	66
2023	67	3	64
2024 and thereafter	390	8	382
	761	32	729

The operating lease agreements for premises, services and equipment expire at various dates through 2052, with an option to renew certain lease agreements for periods of one year to 25 years. Net rental expense on operating leases in2018 was $84 million (2017 – $93 million; 2016 – $145 million).

Other commitments

TransCanada 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.

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, 2018, TransCanada had the following capital expenditure commitments:

- approximately $4.6 billion for its Canadian natural gas pipelines, primarily related to construction costs associated with the construction of the Coastal GasLink and NGTL System pipeline projects
- approximately $0.1 billion for its U.S. natural gas pipelines, primarily related to construction costs associated with Columbia Gas and Columbia Gulf growth projects
- approximately $0.3 billion for its Mexico natural gas pipelines, primarily related to construction of the Sur de Texas, Villa de Reyes and Tula pipeline projects
- approximately $0.4 billion for its Liquids pipelines, primarily related to the development of Keystone XL and construction of White Spruce
- approximately $0.7 billion for its Energy business, primarily related to its proportionate share of commitments for Bruce Power's life extension program
- approximately $0.1 billion for its Corporate segment related to various information technology services agreements.

Contingencies

TransCanada is subject to laws and regulations governing environmental quality and pollution control. Asat December 31, 2018, the Company had accrued approximately $40 million (2017 – $34 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.

TransCanada 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 will not have a material impact on the Company's consolidated financial position or results of operations.

Guarantees

TransCanada and its partner on the Sur de Texas pipeline, IEnova, have jointly guaranteed the financial performance of this entity. Such agreements include a guarantee and a letter of credit which are primarily related to construction services and the delivery of natural gas.

TransCanada and its joint venture partner on Bruce Power, BPC Generation Infrastructure Trust, have each severally guaranteed certain contingent financial obligations of Bruce Power related to a lease agreement and contractor and supplier services.

The Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities. Such agreements include guarantees and letters of credit which are primarily related to delivery of natural gas, construction services and the payment of liabilities. For certain of these entities, any payments made by TransCanada 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 is as follows:

at December 31 (millions of Canadian $)	Term	2018 Potential Exposure[1]	2018 Carrying Value	2017 Potential Exposure[1]	2017 Carrying Value
Sur de Texas	ranging to 2020	**183**	**1**	315	2
Bruce Power	ranging to 2021	**88**	**—**	88	1
Other jointly owned entities	ranging to 2059	**104**	**11**	104	13
		375	**12**	507	16

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

28. CORPORATE RESTRUCTURING COSTS

In mid-2015, the Company commenced a business restructuring and transformation initiative to reduce overall costs and maximize the effectiveness and efficiency of its existing operations. The Company incurred corporate restructuring costs and recorded a provision to allow for planned severance costs in future years, as well as expected future losses under lease commitments.

Cumulatively to December 31, 2018, the Company has incurred costs of $86 million for employee severance and $60 million for lease commitments, net of $157 million related to costs that were recoverable through regulatory and tolling structures. The Company recorded additional provisions in 2018 to reflect the changes in expected future losses under lease commitments. The remaining lease commitments provision at December 31, 2018 is expected to be fully realized by 2027.

Changes in the restructuring liability were as follows:

(millions of Canadian $)	Employee Severance	Lease Commitments	Total
Restructuring liability as at December 31, 2016	36	63	99
Restructuring charges[1]	—	6	6
Accretion expense	—	1	1
Cash payments	(27)	(17)	(44)
Restructuring liability as at December 31, 2017	9	53	62
Restructuring charges[1]	**—**	**42**	**42**
Accretion expense	**—**	**1**	**1**
Cash payments	**(9)**	**(15)**	**(24)**
Restructuring Liability as at December 31, 2018	**—**	**81**	**81**

1 At December 31, 2018, the Company recorded an additional $21 million in Plant operating costs and other in the Consolidated statement of income and $21 million as a regulatory asset on the Consolidated balance sheet related to costs that are recoverable through regulatory and tolling structures in future periods (2017 – $3 million and $3 million, respectively).

29. 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 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 a100 per cent voting interest, the VIE meets the definition of a business and the VIE's assets can be used for general corporate purposes. The Consolidated VIEs whose assets cannot be used for purposes other than for the settlement of the VIE's obligations are as follows:

at December 31 (millions of Canadian $)	2018	2017
ASSETS		
Current Assets		
Cash and cash equivalents	**45**	41
Accounts receivable	**79**	63
Inventories	**24**	23
Other	**13**	11
	161	138
Plant, Property and Equipment	**3,026**	3,535
Equity Investments	**965**	917
Goodwill	**453**	490
Intangible and Other Assets	**8**	3
	4,613	5,083
LIABILITIES		
Current Liabilities		
Accounts payable and other	**88**	137
Dividends payable	**—**	1
Accrued interest	**24**	23
Current portion of long-term debt	**79**	88
	191	249
Regulatory Liabilities	**43**	34
Other Long-Term Liabilities	**3**	3
Deferred Income Tax Liabilities	**13**	13
Long-Term Debt	**3,125**	3,244
	3,375	3,543

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 are as follows:

at December 31 (millions of Canadian $)	2018	2017
Balance sheet		
Equity investments	**4,575**	4,372
Off-balance sheet		
Potential exposure to guarantees	**170**	171
Maximum exposure to loss	**4,745**	4,543

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We, KPMG LLP, consent to the use of our reports, each dated February 13, 2019, 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, KPMG LLP, 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 and No. 333-227114 on Form S-8 of TransCanada Corporation;

- Registration Statements No. 33-13564 and No. 333-6132 on Form F-3 of TransCanada Corporation;

- Registration Statements No. 333-151781, No. 333-161929, No. 333-208585, No. 333-214971, No. 333-218711, No. 333-225941 and No. 333-228848 on Form F-10 of TransCanada Corporation; and,

- Registration Statement No. 333-221898 on Form F-10 of TransCanada PipeLines Limited.

/s/ KPMG LLP
Chartered Professional Accountants

February 14, 2019
Calgary, Canada

Exhibit 31.1

Certifications

I, Russell K. Girling, certify that:

1. I have reviewed this annual report on Form 40-F of TransCanada 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.

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 14, 2019

/s/ RUSSELL K. GIRLING

Russell K. Girling

President and Chief Executive Officer

Certifications

I, Russell K. Girling, 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.

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 14, 2019

/s/ RUSSELL K. GIRLING

Russell K. Girling

President and Chief Executive Officer

Exhibit 31.2

Certifications

I, Donald R. Marchand, certify that:

1. I have reviewed this annual report on Form 40-F of TransCanada 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.
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 14, 2019

/s/ DONALD R. MARCHAND

Donald R. Marchand
Executive Vice-President and
Chief Financial Officer

Certifications

I, Donald R. Marchand, 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.
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 14, 2019

/s/ DONALD R. MARCHAND

Donald R. Marchand
Executive Vice-President and
Chief Financial Officer

Exhibit 32.1

TRANSCANADA 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, Russell K. Girling, the Chief Executive Officer of TransCanada 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 ending December 31, 2018 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/ RUSSELL K. GIRLING

Russell K. Girling
Chief Executive Officer
February 14, 2019

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, Russell K. Girling, 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 the Company's Annual report as filed on Form 40-F for the fiscal year ending December 31, 2018 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/ RUSSELL K. GIRLING

Russell K. Girling
Chief Executive Officer
February 14, 2019

Exhibit 32.2

TRANSCANADA 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, Donald R. Marchand, the Chief Financial Officer of TransCanada 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 ending December 31, 2018 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/ DONALD R. MARCHAND

Donald R. Marchand
Chief Financial Officer
February 14, 2019

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, Donald R. Marchand, 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 the Company's Annual report as filed on Form 40-F for the fiscal year ending December 31, 2018 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/ DONALD R. MARCHAND

Donald R. Marchand
Chief Financial Officer
February 14, 2019