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, 2017 Commission File Number **1-31690**

TRANSCANADA CORPORATION

(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
(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)	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: **None**

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, 2017, 881,375,600 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
were issued and outstanding.

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the file number assigned to the Registrant in connection with such Rule. Yes ¨ 82-_____ No x

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 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 us 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) 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
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

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 Corporation 2017 Management's discussion and analysis and audited consolidated financial statements to shareholders, except as otherwise specifically incorporated by reference in the TransCanada Corporation 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 109 through 184 of the TransCanada Corporation 2017 Management's discussion and analysis and audited consolidated financial statements to shareholders included herein.

B. Management's Discussion and Analysis

For management's discussion and analysis, see pages 5 through 108 of the TransCanada Corporation 2017 Management's discussion and analysis and audited consolidated financial statements to shareholders 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 109 of the TransCanada Corporation 2017 Management's discussion and analysis and audited consolidated financial statements to shareholders included herein.

UNDERTAKING

The 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 90 of the TransCanada Corporation 2017 Management's discussion and analysis and audited consolidated financial statements to shareholders.

AUDIT COMMITTEE FINANCIAL EXPERT

The 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, Mr. Kevin E. Benson 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 the Registrant. The Commission has indicated that the designation of Mr. Lowe, Mr. Benson and Mr. Vandal as audit committee financial experts does not make Mr. Lowe, Mr. Benson or Mr. Vandal "experts" for any purpose, impose any duties, obligations or liability on Mr. Lowe, Mr. Benson 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 Registrant has adopted a code of business ethics ("Code") for its directors, officers, employees and contractors. In 2017, the Code was amended to reflect the safety value change, amend provisions relating to accepting gifts, invitations, and entertainment from suppliers, and amend provisions related to personal relationship disclosure.

The Registrant's Code is available on its website at www.transcanada.com. No waivers have been granted from any provision of the Code during the 2017 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 36 of the TransCanada Corporation Annual information form.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant has 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 79 of the TransCanada Corporation 2017 Management's discussion and analysis and audited consolidated financial statements to shareholders.

IDENTIFICATION OF THE AUDIT COMMITTEE

The Registrant has a separately-designated standing Audit committee. The members of the Audit committee as of February 14, 2018 (unless otherwise indicated) are:

Chair:	**J.E. Lowe**
Members:	**K.E. Benson**
	D.H. Burney (retiring April 27, 2018)
	S. Crétier
	I. Samarasekera
	D.M.G. Stewart
	T. Vandal (as of November 8, 2017)

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:

- planned changes in our business
- our financial and operational performance, including the performance of our subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows and future financing options available to us
- expected dividend growth
- expected costs for planned projects, including projects under construction, permitting and in development
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future accounting changes, commitments and contingent liabilities
- the expected impact of H.R. 1, the Tax Cuts and Jobs Act (U.S. Tax Reform)
- 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

- planned wind-down of our U.S. Northeast power marketing business
- inflation rates and commodity prices
- nature and scope of hedging
- regulatory decisions and outcomes
- interest, tax and foreign exchange rates, including the impact of U.S. Tax Reform
- planned and unplanned outages and the use of our pipeline and energy assets
- integrity and reliability of our assets
- access to capital markets
- anticipated construction costs, schedules and completion dates.

Risks and uncertainties

- our ability to successfully implement our strategic priorities and whether they will yield the expected benefits
- the operating performance of our pipeline and energy assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the availability and price of energy commodities
- the amount of capacity payments and revenues from our energy business
- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration and insurance claims
- performance and credit risk of our counterparties
- changes in market commodity prices
- changes in the political environment
- changes in environmental and other laws and regulations
- competitive factors in the pipeline and energy sectors
- construction and completion of capital projects
- costs for labour, equipment and materials
- access to capital markets
- interest, tax and foreign exchange rates, including the impact of U.S. Tax Reform
- weather
- cyber security
- technological developments
- economic conditions in North America as well as globally.

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.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the 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

Per: /s/ DONALD R. MARCHAND

DONALD R. MARCHAND

Executive Vice-President and Chief Financial Officer

Date: February 15, 2018

DOCUMENTS FILED AS PART OF THIS REPORT

EXHIBITS

13.1	TransCanada Corporation Annual information form for the year ended December 31, 2017.
13.2	Management's discussion and analysis (included on pages 5 through 108 of the TransCanada Corporation 2017 Management's discussion and analysis and audited consolidated financial statements to shareholders).
13.3	2017 Audited consolidated financial statements (included on pages 109 through 184 of the TransCanada Corporation 2017 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, 2017.
23.1	Consent of KPMG LLP, Chartered Professional Accountants, Independent Registered Public Accounting Firm.
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 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.
99.1	A copy of the Registrant's Code of Business Ethics Policy as amended (filed with the Securities and Exchange Commission as part of a Form 6-K report on February 2, 2018 and incorporated by reference herein).
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.

EXHIBIT 13.1

TransCanada Corporation

2017 Annual information form

February 14, 2018

Contents

PRESENTATION OF INFORMATION 2
FORWARD-LOOKING INFORMATION 2
TRANSCANADA CORPORATION 4
Corporate structure 4
Intercorporate relationships 4
GENERAL DEVELOPMENT OF THE BUSINESS 5
Natural Gas Pipelines 5
Liquids Pipelines 13
Energy 16
BUSINESS OF TRANSCANADA 18
Natural Gas Pipelines 18
Liquids Pipelines 18
Regulation of Natural Gas Pipelines and Liquids Pipelines 19
Energy 20
GENERAL 21
Employees 21
Corporate restructuring and business transformation 21
Health, safety and environmental protection and social policies 21
RISK FACTORS 23
DIVIDENDS 23
DESCRIPTION OF CAPITAL STRUCTURE 23
Share capital 23
CREDIT RATINGS 26
Moody's 26
S&P 27
Fitch 27
DBRS 27
MARKET FOR SECURITIES 28
Common shares 28
Preferred shares 29
DIRECTORS AND OFFICERS 30
Directors 30
Board committees 32
Officers 33
Conflicts of interest 34
CORPORATE GOVERNANCE 34
AUDIT COMMITTEE 35
Relevant education and experience of members 35
Pre-approval policies and procedures 36
External auditor service fees 36
LEGAL PROCEEDINGS AND REGULATORY ACTIONS 37
TRANSFER AGENT AND REGISTRAR 37
MATERIAL CONTRACTS 37
INTEREST OF EXPERTS 37
ADDITIONAL INFORMATION 37
GLOSSARY 38
SCHEDULE A 39
SCHEDULE B 40

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, 2017 (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 14, 2018 (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 document include information about the following, among other things:

- planned changes in our business
- our financial and operational performance, including the performance of our subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows and future financing options available to us
- expected dividend growth
- expected costs for planned projects, including projects under construction, permitting and in development
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future accounting changes, commitments and contingent liabilities
- the expected impact of H.R. 1, the Tax Cuts and Jobs Act (U.S. Tax Reform)
- 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

- planned wind-down of our U.S. Northeast power marketing business
- inflation rates and commodity prices
- nature and scope of hedging
- regulatory decisions and outcomes
- interest, tax and foreign exchange rates, including the impact of U.S. Tax Reform
- planned and unplanned outages and the use of our pipeline and energy assets
- integrity and reliability of our assets
- access to capital markets
- anticipated construction costs, schedules and completion dates.

Risks and uncertainties

- our ability to successfully implement our strategic priorities and whether they will yield the expected benefits
- the operating performance of our pipeline and energy assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the availability and price of energy commodities
- the amount of capacity payments and revenues from our energy business
- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration and insurance claims
- performance and credit risk of our counterparties
- changes in market commodity prices
- changes in the political environment
- changes in environmental and other laws and regulations
- competitive factors in the pipeline and energy sectors
- construction and completion of capital projects
- costs for labour, equipment and materials
- access to capital markets
- interest, tax and foreign exchange rates, including the impact of U.S. Tax Reform
- weather
- cyber security
- technological developments
- economic conditions in North America as well as globally.

You can read more about these factors and others in 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.

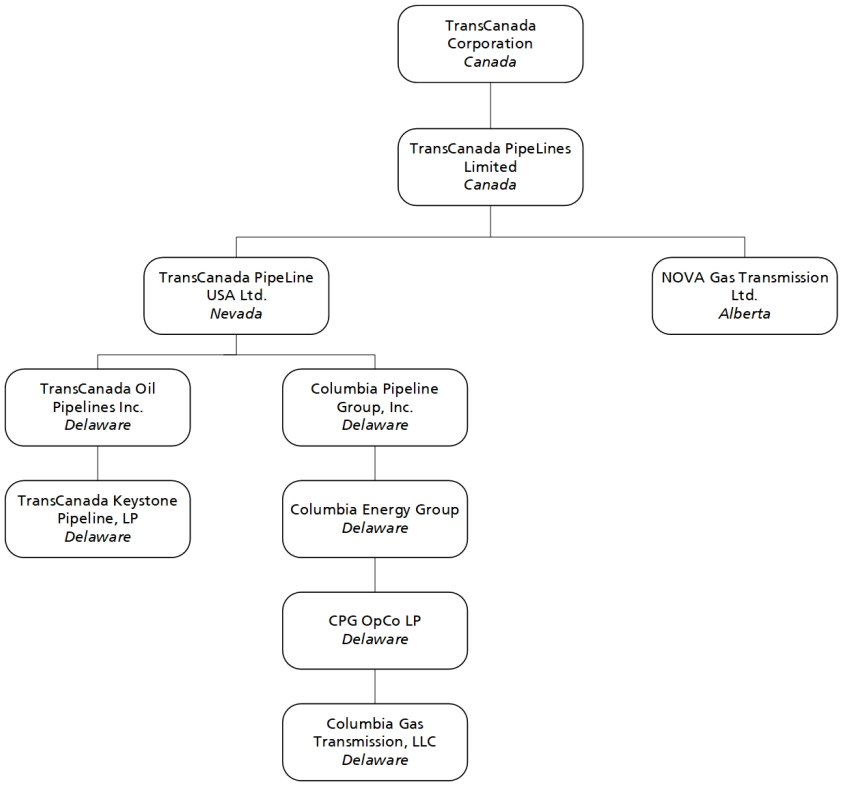
TransCanada Corporation

CORPORATE STRUCTURE

Our head office and registered office are located at 450 – 1st 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 as at Year End.

General development of the business

We operate in three core businesses – Natural Gas Pipelines, Liquids Pipelines and Energy. As a result of our acquisition of Columbia Pipeline Group, Inc. (Columbia) on July 1, 2016 and the sale of the U.S. Northeast power business, we determined that a change in our operating segments was appropriate. Accordingly, we consider ourselves to be operating in the following five segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines and Energy. This provides information that is aligned with how management decisions about our business are made and how performance of our business is assessed. We also have a non-operational Corporate segment consisting of corporate and administrative functions that provide governance and other support to our operational 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 the non-regulated 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 2018. 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	
2015	The NGTL System had approximately $6.7 billion of new supply and demand facilities under development and we continued to advance several of these capital expansion projects by filing the regulatory applications with the National Energy Board (Canada) (NEB). In 2015, we placed approximately $0.35 billion of facilities in service.
2016	In 2016, the NGTL System continued to develop new supply and demand facilities. We had approximately $2.3 billion of facilities that received regulatory approval and approximately $0.45 billion under construction. On October 6, 2016, the NEB recommended government approval of the Towerbirch Project and the continued use of the existing rolled-in toll methodology for the project. On October 31, 2016, the Government of Canada also 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 December 2016, we announced the $0.6 billion Saddle West expansion of the NGTL System to increase natural gas transportation capacity on the northwest portion of our system, consisting of 29 km (18 miles) of 36-inch pipeline looping of existing mainlines, the addition of five compressor units at existing station sites and new metering facilities. The project is underpinned by incremental firm service contracts and is expected to be in-service in 2019. In 2016, we placed approximately $0.5 billion of facilities in service.
2017	In March 2017, the Government of Canada approved the $0.4 billion Towerbirch Project, which consists of a 55 km (34 mile), 36-inch pipeline loop and a 32 km (20 mile), 30-inch pipeline extension of the NGTL System in northwest Alberta and northeast British Columbia (B.C.), which was subsequently placed in service in November 2017. In June 2017, we announced a new $2 billion expansion program on our NGTL System based on new contracted customer demand for approximately 3.2 PJ/d (3 Bcf/d) of incremental firm receipt and delivery services, subject to regulatory approvals. In 2017, we placed approximately $1.7 billion of new facilities in service on the NGTL System, and reduced project estimates by $0.6 billion.
2018	In February 2018, we announced a new NGTL System expansion totaling $2.4 billion, with in-service dates between 2019 and 2021. The new expansion program includes approximately 375 km (233 miles) of 16- to 48-inch pipeline, four compressor units totaling 120 MW, and associated metering stations and facilities. We anticipate incremental firm receipt contracts of 664 TJ/d (620 MMcf/d) and firm delivery contracts to our major border export and intra-basin delivery locations of 1.1 PJ/d (1.0 Bcf/d).

Date	Description of development
NGTL Revenue Requirement Settlements	
2015	In February 2015, we received NEB approval for our revenue requirement settlement with our shippers on the NGTL System. The terms of the settlement included the continuation of the 2014 return on equity (ROE) of 10.1 per cent on 40 per cent deemed equity, continuation of the 2014 depreciation rates and a mechanism for sharing variances above and below a fixed operating, maintenance and administration (OM&A) expense amount that was based on an escalation of 2014 actual costs. In December 2015, we reached a two-year revenue requirement agreement (2016-2017 Settlement) with customers and other interested parties on the annual costs, including ROE and depreciation required to operate the NGTL System for 2016 and 2017. The 2016-2017 Settlement fixed ROE at 10.1 per cent on 40 per cent deemed 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.
2017	The 2016-2017 Settlement expired on December 31, 2017. We continue to work with interested parties towards a new revenue requirement arrangement for 2018 and longer. While these discussions are underway, NGTL is operating under interim tolls for 2018 that were approved by the NEB on November 24, 2017.
North Montney	
2015	In June 2015, the NEB approved the $1.7 billion North Montney Mainline (NMML) project, subject to certain terms and conditions. Under one of these conditions, construction on the NMML project was only to begin after a positive final investment decision (FID) had been made on the Pacific North West liquefied natural gas (LNG) project (PNW LNG). The NMML project provides substantial new capacity on the NGTL System to meet the transportation requirements associated with rapidly increasing development of natural gas resources in the Montney supply basin in northeastern B.C. The NMML project connects Montney and other Western Canadian Sedimentary Basin (WCSB) supply to existing and new natural gas markets, including LNG markets. The project also includes an interconnection with our Prince Rupert Gas Transmission Project (PRGT) to provide natural gas supply to the proposed PNW LNG liquefaction and export facility near Prince Rupert, B.C.
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, 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 on the NGTL System to remove the condition that the NMML project could only proceed once a positive FID was made for the PNW LNG project. The NMML project is now underpinned by restructured 20-year commercial contracts with shippers and is not dependent on PNW LNG project proceeding. A hearing on the matter began the week of January 22, 2018 and a decision from the NEB is anticipated in second quarter 2018.
Sundre Crossover Project	
2017	On December 28, 2017, the NEB approved the Sundre Crossover project on the NGTL System. The approximate $100 million, 21 km (13 mile), 42-inch pipeline project will increase delivery of 245 TJ/d (229 MMcf/d) to the Alberta/ B.C. border to connect with TransCanada downstream pipelines. In-service is planned for April 1, 2018.
Canadian Mainline – Kings North and Station 130 Facilities	
2016	In fourth quarter 2016, we placed in service the approximate $310 million Kings North Connector and the approximate $75 million compressor unit addition at Station 130 on the Canadian Mainline system. These two projects are consistent with our current LDC Settlement (defined below) with our shippers and provide optionality to access alternative supply sources while contracting for increased short-haul transportation service within the Eastern Triangle area of the Canadian Mainline system.
Canadian Mainline – Eastern Mainline Project	
2015	In August 2015, we announced that we had reached an agreement with eastern local distribution companies (LDCs) that resolved their issues with the Energy East pipeline project and the Eastern Mainline project. Application amendments were filed in December 2015 that reflected the agreement. The agreement provided gas consumers in eastern Canada with sufficient natural gas transmission capacity and provides for reduced natural gas transmission costs.
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.

Date	Description of development
Canadian Mainline – Other Expansions	
2016	In addition to the Eastern Mainline Project, new facilities investments totaling approximately $700 million over the 2016-2017 period in the Eastern Triangle portion of the Canadian Mainline were required to meet contractual commitments from shippers. In third quarter 2016, we launched an open season for the Canadian Mainline, seeking binding commitments on our new long-term, fixed-price proposal to transport WCSB supply from the Empress receipt point in Alberta to the Dawn hub in Southern Ontario. The open season for the proposed service resulted in bids that fell short of the volumes required to make the proposal viable. On November 15, 2016 we announced we would not proceed with the service offering. Refer to the *Canadian Mainline – Kings North and Station 130 Facilities* section above.
2017	Including the Vaughan Loop, which was placed in service in November 2017, we had approximately $245 million of additional investment to meet contractual commitments from shippers that went into service in 2017 on the Canadian Mainline. The Canadian Mainline also received requests for expansion capacity to the southern Ontario market plus delivery to Atlantic Canada via the Trans-Québec & Maritimes and PNGTS (defined below) systems. The requests for approximately 86 TJ/d (80 MMcf/d) of firm service underpin the need for new compression at the existing Maple compressor site. Customers have executed 15-year precedent agreements to proceed with the project, which has an estimated cost of $110 million. An application to the NEB seeking project approval was filed on November 2, 2017. We have requested a decision by the NEB to proceed with the project in first quarter 2018 to meet an anticipated in-service date of November 1, 2019.
Dawn Long-Term Fixed-Price Service	
2017	On November 1, 2017, we began offering a new NEB-approved service on the Mainline referred to as the Dawn Long-Term Fixed-Price (LTFP) service. This LTFP 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.
Canadian Mainline Settlement	
2015	In 2015, the Canadian Mainline began operating under the NEB-approved Canadian Mainline's 2015-2030 Tolls and Tariff Application.
2017	While the 2015-2030 settlement (LDC Settlement) specified tolls for 2015 to 2020, the NEB ordered a toll review halfway through this six-year period, to be filed by December 31, 2017. The 2018-2020 toll review must include costs, forecast volumes, contracting levels, the deferral account balance, and any other material changes. A supplemental agreement for the 2018-2020 period was executed between TransCanada and eastern LDCs on December 8, 2017, and filed for approval with the NEB on December 18, 2017 (the Supplemental Agreement). The Supplemental Agreement, supported by a majority of Canadian Mainline stakeholders, proposes lower tolls, preserves an incentive arrangement that provides an opportunity for 10.1 per cent, or greater return, on a 40 per cent deemed equity and describes the revenue requirements and billing determinants for the 2018-2020 period. We anticipate the NEB will provide directions and process to adjudicate the application in first quarter 2018. Interim tolls for 2018, as established by the Supplemental Agreement, were filed and subsequently approved by the NEB on December 19, 2017.
LNG PIPELINE PROJECTS	
Prince Rupert Gas Transmission	
2015	In June 2015, PNW LNG announced a positive FID for its proposed liquefaction and export facility, subject to two conditions. The first condition, approval by the Legislative Assembly of B.C. of a project development agreement between PNW LNG and the Province of B.C., was satisfied in July 2015. The second condition was a positive regulatory decision on PNW LNG's environmental assessment by the Government of Canada. Environmental permits for the project were received in November 2014 from the B.C. Environmental Assessment Office (BCEAO). In third quarter 2015, we received all remaining permits from the B.C. Oil and Gas Commission (OGC). With these permits, PRGT received all of the primary regulatory permits required for the project.
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.

Date	Description of development
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 LNG 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 September 2017, an approximate $80 million payment was received related to costs incurred since inception of the project. Following a payment of $8 million in fourth quarter 2017, additional quarterly payments of approximately $7 million will be received until further notice. We continue to work with LNG Canada under the agreement towards an FID. Coastal GasLink filed an amendment to the Environmental Assessment Certificate in November 2017 for an alternate route on a portion of the pipeline. A decision from the BCEAO is expected in 2018. Should the project not proceed, our project costs, including carrying charges are fully recoverable.

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.
Leach XPress	
2015	The Federal Energy Regulatory Commission (U.S.) (FERC) 7(C) application for this Columbia Gas project was filed in June 2015. 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. The project 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.
2016	The Final Environmental Impact Statement (FEIS) for the project was received in September 2016.
2018	The US$1.6 billion project was placed in service on January 1, 2018.
Mountaineer XPress	
2016	The FERC 7(C) application for this Columbia Gas project was filed in April 2016. The project is designed to transport approximately 2.9 PJ/d (2.7 Bcf/d) of Marcellus and Utica gas supply to delivery points along the pipeline 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 on December 29, 2017. The project is expected to have a US$0.6 billion increase in its capital project cost due to increased construction cost estimates. As a result of a cost sharing mechanism, overall project returns are not anticipated to be materially affected. The US$2.6 billion project is expected to be placed in service in fourth quarter 2018.
Rayne XPress	
2015	The FERC 7(C) application for this Columbia Gulf project was filed in July 2015. 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.
2016	The FEIS for the project was received in September 2016.
2017	The US$0.4 billion project was placed in service on November 2, 2017.
Gulf XPress	
2016	The FERC 7(C) application for this Columbia Gulf project was filed in April 2016. The project is designed to transport approximately 0.9 Bcf/d associated with the Mountaineer XPress expansion to various delivery points on Columbia Gulf and the Gulf Coast. The project consists of adding seven greenfield midpoint compressor stations along the Columbia Gulf route totaling 182.7 MW (245,000 hp).
2017	The FERC certificate for Gulf Xpress project was received on December 29, 2017. We expect this project, with an estimated capital investment of US$0.6 billion, to be placed in service in 2018.
Cameron Access Project	
2015	The FERC certificate for this Columbia Gulf project was received in September 2015. The project is designed to transport approximately 0.8 Bcf/d of gas supply to the Cameron LNG export terminal in Louisiana. The project consists of 55 km (34 miles) of 36-inch greenfield pipeline, 11 km (seven miles) of 30-inch looping and 9.7 MW (13,000 hp) of greenfield compression. We expect this project, with an estimated capital investment of US$0.3 billion, to be in service in first quarter 2018.

Date	Description of development
WB XPress	
2015	The FERC 7(C) application for both segments of this Columbia Gas project was filed in December 2015. The project is designed to transport approximately 1.3 Bcf/d of Marcellus gas supply westbound (0.8 Bcf/d) to the Gulf Coast via an interconnect with the Tennessee Gas Pipeline, and eastbound (0.5 Bcf/d) to Mid-Atlantic markets. The project consists of 47 km (29 miles) of various diameter pipeline, 338 km (210 miles) of restoring and uprating maximum operating pressure of existing pipeline, 29.8 MW (40,000 hp) of greenfield compression and 99.9 MW (134,000 hp) of brownfield compression.
2017	The FERC certificate for the WB XPress project was received in November 2017. We expect this project, with an estimated capital investment of US$0.8 billion, to be fully in service in 2018.
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 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.
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.
Gibraltar	
2016	The first phase of the multi-phase project was completed in December 2016.
2017	The US$0.3 billion Midstream project to construct an approximate 1,000 TJ/d (934 MMcf/d) dry gas header pipeline in southwest Pennsylvania was placed in service on November 1, 2017.
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	
2015	We test goodwill for impairment annually or more frequently if events or changes in circumstances lead us to believe it might be impaired. Our share of the goodwill related to Great Lakes, net of non-controlling interests, was US$386 million at December 31, 2015.
2016	Our share of the goodwill related to Great Lakes, net of non-controlling interests, was US$382 million at December 31, 2016.
2017	On October 30, 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. The settlement, if approved by the FERC, will decrease Great Lakes' maximum transportation rates by 27 per cent effective October 1, 2017. Great Lakes expects that the impact from other changes, including the recent long-term transportation contract with the Canadian Mainline as described below, other revenue opportunities on the system and the elimination of the revenue sharing mechanism with its customers, will essentially offset the full year impact of the reduction in Great Lakes' rates beginning in 2018. In conjunction with the Canadian Mainline's LTFP service (see *Canadian Regulated Pipelines – Dawn Long-Term Fixed-Price Service* above), Great Lakes entered into a new ten-year gas transportation contract with the Canadian Mainline. This contract received NEB approval in September 2017, effective November 1, 2017, and contains volume reduction options up to full contract quantity beginning in year three.

Date	Description of development
2017 (continued)	In relation to goodwill impairment, 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$379 million at Year End. At Year End, the estimated fair value of Great Lakes exceeded its carrying value by less than ten per cent. Further information about impairment of goodwill can be found in the MD&A in the *Other Information – Critical Accounting Estimates – Impairment of long-lived assets, equity investments and goodwill* section, which section of the MD&A is incorporated by reference herein.
Northern Border	
2017	Northern Border filed a rate settlement with the FERC on December 4, 2017, reflecting a settlement-in-principle with its shippers, which precludes the need to file a general rate case as contemplated by its previous 2012 settlement. Northern Border anticipates that the FERC will accept the settlement agreement and that it will be unopposed. This is expected to provide Northern Border with rate stability over the longer term. We have a 12.9 per cent indirect ownership interest in Northern Border though TC PipeLines, LP (TCLP).
Portland Natural Gas Transmission System (PNGTS)	
2016	In January 2016, we closed the sale of our 49.9 per cent of our total 61.7 per cent interest in PNGTS to 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 PNGTS 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 PNGTS 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 PNGTS debt. In December 2017, PNGTS 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 PNGTS 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 (PXP) will proceed concurrently with upstream capacity expansions. The in-service dates of PXP are being phased-in over a three-year period beginning November 1, 2018.
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. On March 31, 2016, we acquired an additional 4.87 per cent interest in Iroquois for an aggregate purchase price of US$54 million and on May 1, 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 PNGTS to TCLP. Refer to the *Portland Natural Gas Transmission System* section above.
Gas Transmission Northwest LLC (GTN)	
2015	In April 2015, we closed the sale of our remaining 30 per cent interest in GTN to TCLP for an aggregate purchase price of US$457 million. Proceeds were comprised of US$246 million in cash, the assumption of US$98 million of debt, being proportional GTN debt and US$95 million of new Class B units of TCLP.
TC Offshore LLC (TC Offshore)	
2015	We entered into an agreement to sell TC Offshore to a third party. As a result, at December 31, 2015, the related assets and liabilities were classified as held for sale and were recorded at their fair values less costs to sell. This resulted in a pre-tax loss provisions of $125 million recorded in 2015.
2016	We completed the sale of TC Offshore in March 2016.
LNG PIPELINE PROJECTS	
Alaska LNG Project	
2015	In November 2015, we sold our interest in the Alaska LNG project to the State of Alaska. The proceeds of US$65 million from this sale provide a full recovery of costs incurred to advance the project since January 1, 2014 including a carrying charge. With this sale, our involvement in developing a pipeline system for commercializing Alaska North Slope natural gas ceased.

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 Transportation Service Agreement (TSA) for 717 TJ/d (670 MMcf/d) with the Comisión Federal de Electricidad (Mexico) (CFE). The Topolobampo project is a 560 km (348 mile), 30-inch pipeline that will receive gas from the upstream pipelines near El Encino, in the state of Chihuahua, and deliver natural gas from these interconnecting pipelines to delivery points along the pipeline route including our Mazatlán pipeline at El Oro, in the state of Sinaloa.
2017	The Topolobampo project is substantially complete, excluding a 20 km (12 mile) section due to delays experienced by the Secretary of Energy, the government department which conducts indigenous consultations in Mexico. The issue has been resolved and construction on this final section is expected to be completed in second quarter 2018. 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 estimate is approximately US$1.2 billion, an increase of US$0.2 billion from the original estimate, due to the delays.
Mazatlán	
2015	The Mazatlán project is a 430 km (267 mile), 24-inch pipeline running from El Oro to Mazatlán, in the state of 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.
2016	Physical construction was completed in 2016 and was awaiting natural gas supply from upstream interconnecting pipelines. We met our obligations and have been collecting revenue as per provisions in the contract and per the original TSA service commencement date of December 2016.
2017	The Mazatlán project was commissioned and brought into full service in July 2017.
Tula	
2015	In November 2015, we were awarded the contract to build, own and operate the US$0.7 billion, 36-inch, 300 km (186 mile) pipeline with a 16-inch, 24 km (15 mile) 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, Querétaro 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. Project completion has been revised to late 2019 due to delays experienced by the Secretary of Energy, the governmental department which conducts indigenous consultations in Mexico. The delay has been recognized by the CFE as a force majeure event and we are finalizing amending agreements to formalize the schedule and payment impacts. As a result of the delay and increased cost of land and permitting, estimated project costs have increased by US$0.1 billion from the original estimate. Full completion of the project has been revised to the end of 2019.
Villa de Reyes	
2016	In April 2016, we were awarded the contract to build, own and operate the Villa de Reyes pipeline in Mexico. Construction of the pipeline is supported by a 25-year natural gas TSA for 949 TJ/d (886 MMcf/d) with the CFE. We expect to invest approximately US$0.6 billion to construct 36- and 24-inch pipelines totaling 420 km (261 miles). The bi-directional pipeline will transport natural gas between Tula, in the state of Hidalgo, and Villa de Reyes, in the state of San Luis Potosí. The project will interconnect with our Tamazunchale and Tula pipelines as well as with other transporters in the region.
2017	Construction of the project has commenced, however, delays due to archeological investigations by state authorities have caused the in-service date to be revised to late 2018. The delay has been recognized as a force majeure event by the CFE and we are finalizing amending agreements to formalize the schedule and payment impacts. As a result of the delay and increased cost of land and permitting, estimated project costs have increased by US$0.2 billion from the original estimate.
Sur de Texas	
2016	The US$2.1 billion 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, approximately 800 km (497 mile) pipeline will start offshore in the Gulf of Mexico, at the border point near Brownsville, Texas, and end in Tuxpan in the state of Veracruz. The project will deliver natural gas to our Tamazunchale and Tula pipelines and to other transporters in the region.
2017	Pipeline construction is progressing toward an anticipated in-service date of late 2018, with approximately 60 per cent of the off-shore construction completed as at Year End.

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	
2015	In 2015, we entered into an agreement with CITGO Petroleum (CITGO) to construct a US$65 million pipeline connection between the Keystone Pipeline and CITGO's Sour Lake, Texas terminal, which supplies their 425,000 Bbl/d Lake Charles, Louisiana refinery. We secured additional long-term contracts bringing our total contract position up to 545,000 Bbl/d.
2016	In January 2016, we entered into an agreement with Magellan Midstream Partners L.P. (Magellan) to connect our Houston Terminal to Magellan's Houston and Texas City, Texas delivery system. We will own 50 per cent of this US$50 million pipeline project which will enhance connections for our Keystone Pipeline to the Houston market. On April 2, 2016, we shut down the Keystone Pipeline after a leak was detected along the pipeline right-of-way in Hutchinson County, South Dakota. We reported the total volume of the release of 400 barrels to the National Response Centre (NRC) and the Pipeline and Hazardous Materials Safety and Administration (PHMSA). Temporary repairs were completed and the Keystone Pipeline was restarted by mid-April 2016. Shortly thereafter in early May 2016, permanent pipeline repairs were completed and restoration work was completed by early July 2016. Corrective measures required by PHMSA were completed in September 2016. This shutdown did not significantly impact our 2016 earnings. 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 Sour Lake pipeline connection between the Keystone Pipeline and CITGO's Sour Lake, Texas terminal was placed into 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. On November 16, 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. Further investigative activities and corrective measures required by PHMSA are planned for 2018. This shutdown did not have a significant impact on our 2017 earnings.
Keystone XL	
2015	In January 2015, the Nebraska State Supreme Court vacated a lower court's ruling, which had given the state Public Service Commission (PSC) rather than the governor, the authority to approve an alternative route through Nebraska for Keystone XL, as unconstitutional. As a result, the Governor's January 2013 approval of the alternate route through Nebraska for Keystone XL remained valid. Landowners filed lawsuits in two Nebraska counties seeking to enjoin Keystone XL from condemning easements on state constitutional grounds. The decision on the Keystone XL Presidential permit application was delayed throughout 2015 by the U. S. Department of State (DOS) and was ultimately denied in November 2015. At December 31, 2015, as a result of the denial of the Presidential permit, we evaluated our investment in Keystone XL and related projects, including Keystone Hardisty Terminal, for impairment. As a result of our analysis, we determined that the carrying amount of these assets was no longer recoverable, and recognized a total non-cash impairment charge of $3.7 billion ($2.9 billion after-tax). The impairment charge was based on the excess of the carrying value of $4.3 billion over the fair value of $621 million, which includes $93 million fair value for Keystone Hardisty Terminal. The calculation of this impairment is discussed further in the Other information – Critical accounting estimates section of the MD&A, which section is incorporated by reference herein. In November 2015, we withdrew our application to the PSC for approval of the route for Keystone XL in the state. The application was initially filed in October 2015. The withdrawal was made without prejudice to potentially refile if we elect to pursue the project.
2016	On January 5, 2016, the South Dakota Public Utilities Commission (PUC) accepted Keystone XL's certification that it continued to comply with the conditions in its existing 2010 permit authority in the state. On January 6, 2016, we filed a Notice of Intent to initiate a claim under Chapter 11 of North American Free Trade Agreement (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. On January 5, 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.

Date	Description of development
2017	On January 24, 2017, the U.S. President signed a Presidential Memorandum inviting TransCanada to refile an application for the U.S. Presidential Permit. On January 26, 2017, we filed a Presidential Permit application with the DOS for the project. In February 2017, we filed an application with the PSC to seek approval for the Keystone XL pipeline route through the state. In March 2017, the DOS issued a U.S. Presidential Permit authorizing construction of the U.S./ Canada border crossing facilities of the Keystone XL project. We discontinued our claim under Chapter 11 of NAFTA and withdrew the U.S. Constitutional challenge. Later 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 on November 22, 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 the Keystone XL project from Hardisty, Alberta to Cushing, Oklahoma and the U.S. Gulf Coast. The successful open season concluded on October 26, 2017. On November 20, 2017, we received PSC approval for the alternative mainline route. On November 24, 2017, 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 on December 19, 2017. On December 27, 2017, opponents of the Keystone XL project and intervenors in the Keystone XL 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. In January 2018, we secured sufficient commercial support to commence construction preparation for the Keystone XL project. Subject to certain conditions, we expect to commence primary construction in 2019, and once commenced, construction is anticipated to take approximately two years to complete.
Energy East	
2015	In April 2015, we announced that the proposed marine terminal and associated tank terminal in Cacouna, Québec would not be built as a result of the recommended reclassification of the beluga whale, indigenous to the site, as an endangered species. In November 2015, following consultation with stakeholders and shippers, we announced the intention to amend the Energy East pipeline application to remove a port in Québec and proceed with a single marine terminal in Saint John, New Brunswick. In December 2015, we filed an amendment to the existing project application with the NEB that adjusted the proposed route, scope and capital cost of the project reflecting refinement and scope change including the removal of the port in Québec.
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. The Chair of the NEB and the Vice-Chair, who is also a panel member, recused themselves of any further duties related to the project. As a result, all hearings for the project were adjourned until further notice.
2017	On January 9, 2017, the NEB appointed three new permanent panel members to undertake the review of the Energy East and Eastern Mainline projects. On January 27, 2017, the new NEB panel members voided all decisions made by the previous hearing panel members and all decisions were removed from the official hearing record. We were not required to refile the application and parties were not required to reapply for intervener status. On September 7, 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 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. On October 5, 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 Développement durable, de l'Environnement et la Lutte contre les changements climatiques (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 allowance of funds used during construction (AFUDC) capitalized since inception, and recorded a $954 million after-tax non-cash 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.

Date	Description of development
Grand Rapids	
2015	In August 2015, we announced a joint venture between Grand Rapids and Keyera Corp. (Keyera) for provision of diluent transportation service on the 20-inch pipeline between Edmonton and Fort Saskatchewan, Alberta. The joint venture was incorporated into Grand Rapids to provide enhanced diluent supply alternatives to our shippers.
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 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 late August 2017, the Grand Rapids pipeline, jointly owned by TransCanada and PetroChina Canada Ltd. (formerly Brion), was placed in service. The 460 km (287 mile) crude oil transportation system connects producing areas northwest of Fort McMurray, Alberta to terminals in the Edmonton/ Heartland region.
Northern Courier	
2016	Construction continued on the Northern Courier pipeline to transport 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	In November 2017, the Northern Courier pipeline, a 90 km (56 mile) pipeline system, achieved commercial in-service.
White Spruce	
2016	In December 2016, we finalized a long-term transportation agreement to develop and construct the 20-inch White Spruce pipeline, which would transport crude oil from Canadian Natural Resources Limited's Horizon facility in northeast Alberta, to the Grand Rapids pipeline system. The total capital cost for the project amounts to approximately $200 million.
2018	In first quarter 2018, we anticipate receiving a decision from the AER on the regulatory permit to construct the $200 million White Spruce pipeline. Due to the delay in the regulatory process, we expect the White Spruce pipeline to be in-service in 2019.
Upland Pipeline	
2015	In April 2015, we filed an application to obtain a U.S. Presidential permit for the Upland pipeline, which would provide crude oil transportation from and between multiple points in North Dakota and interconnect with the Energy East pipeline system at Moosomin, Saskatchewan. The commercial contracts that we executed for Upland pipeline were conditioned on the Energy East pipeline project proceeding.
2016	We reviewed the Canadian federal government's interim measures for pipeline reviews to assess their impact to Upland Pipeline.
2017	On October 5, 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 notified 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 on October 5, 2017, that we would no longer be pursuing the U.S. Presidential Permit application for that project. Refer to the *Energy East* section above.
Liquids Marketing	
2015	We established a liquids marketing business to expand into other areas of the liquids business value chain. Our liquids marketing business provides customers with a variety of crude oil marketing services including transportation, storage and crude oil supply, primarily transacted through purchase and sale of physical crude oil.

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	
2015	In June 2015, the Alberta government announced a renewal and change to the Specified Gas Emitters Regulation (SGER) in Alberta. Since 2007, under the SGER, established industrial facilities with greenhouse gas (GHG) emissions above a certain threshold are required to reduce their emissions by 12 per cent below an average intensity baseline, and a carbon levy of $15 per tonne is placed on emissions above this target. The changes to the SGER included an increase in the emissions reductions target to 15 per cent in 2016 and 20 per cent in 2017, along with an increase in the carbon levy to $20 per tonne in 2016 and $30 per tonne in 2017. Starting in 2018, coal-fired generators will pay $30 per tonne of CO2 on emissions above what Alberta's cleanest natural gas-fired plant would emit to produce an equivalent amount of electricity.
2016	On March 7, 2016, we issued notice to the Balancing Pool to terminate our Alberta PPAs. On July 22, 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. The outcome of this court application could have affected resolution of the arbitration of the Sheerness, Sundance A and Sundance B 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.
Ontario Cap and Trade	
2016	Legislation enabling Ontario's cap and trade program came into force effective July 1, 2016. This regulation set a limit on annual province-wide GHG emissions beginning in January 2017 and introduced a market to administer the purchase and trading of emissions allowances. The regulation places the compliance obligation for emissions from our natural gas-fired power facilities on local gas distributors, with the distributors then flowing the associated costs to the facilities themselves. The IESO has proposed contract amendments for contract holders to address costs and other issues associated with this change in law. We do not expect a significant overall impact to our Energy business as a result of this new regulation.
Napanee	
2015	In January 2015, we began construction activities on our 900 MW natural gas-fired power plant at Ontario Power Corporation's (OPG) Lennox site in in the town of Greater Napanee.
2017	Construction continued on the power plant. We expect to invest approximately $1.3 billion in the Napanee facility during construction and commercial operations are expected to begin in fourth quarter 2018. Costs have increased due to delays in the construction schedule. Once in service, production from the facility is fully contracted with IESO for a 20-year period.
Bécancour	
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.
2016	In November 2016, HQ released a new ten-year supply plan indicating additional peak winter capacity from Bécancour is not required at this time. Prior to this development, the regulator in Québec, Régie de l'énergie, reversed its initial decision to approve this agreement. Management does not expect further developments at Bécancour until November 2019 when the next ten-year supply plan is filed.
Bruce Power	
2015	Bruce Power entered into an agreement with the IESO 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, effective January 1, 2016, allows Bruce Power to immediately invest in life extension activities for Units 3 through 8. Our estimated share of investment in the Asset Management program to be completed over the life of the agreement is approximately $2.5 billion (2014 dollars). Our estimated share of investment in the Major Component Replacement (MCR) work that is expected to begin in 2020 is approximately $4 billion (2014 dollars). Under certain conditions, Bruce Power and the IESO can elect to not proceed with the remaining MCR investments should the cost exceed certain thresholds or prove to not provide sufficient economic benefits. The agreement was structured to account for changing cost inputs over time, including ongoing operating costs and additional capital investments.

Date	Description of development
2015 (continued)	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 and MCR capital 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. In 2015, we recognized a $36 million charge, representing our proportionate share on the retirement of Bruce Power debt in conjunction with this merger.
2016	Bruce Power issued bonds and borrowed under its bank credit facility as part of a financing program to fund its capital program and make distributions to its partners. Distributions received by us from Bruce Power in second quarter 2016 included $725 million from this financing program.
2017	In February 2017, Bruce Power issued senior notes in capital markets under its financing program and distributed $362 million to TransCanada.
Ontario Solar	
2017	On October 24, 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 resulting in a gain of $127 million ($136 million after-tax).
U.S. POWER	
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) 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. The transaction is expected to close in first quarter 2018, subject to regulatory and other approvals.
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. Refer to the *Monetization of U.S. Northeast Power Business* section above.

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 *About our business – Our strategy, 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

We are a leading North American energy infrastructure company focused on Natural Gas Pipelines, Liquids Pipelines and Energy. Refer to the *About our business – Three core businesses – 2017 Financial highlights – Consolidated results* section of the MD&A for our revenues from operations by segment, for the years ended December 31, 2017 and 2016, 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 and individual facilities, interconnecting pipelines and other businesses across Canada, the U.S. and Mexico. 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 and Oklahoma, as well as connecting U.S. crude oil supplies from the Cushing, Oklahoma hub to refining and export markets in the U.S. Gulf Coast. We also provide intra-Alberta liquids transportation. Our proposed future pipeline infrastructure would expand capacity for Canadian and U.S. crude oil to access key markets. We will also pursue enhancing our transportation service offerings to other areas of the liquids pipelines business value chain.

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, the **Systems**) 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 Canadian Mainline, however, operates under a fixed toll arrangement for its longer term firm transportation service and has the flexibility to price its shorter term and discretionary services in order to maximize its revenue. A Supplemental Agreement for the 2018-2020 period for the Canadian Mainline was filed for approval with the NEB in December 2017. Further information relating to the Canadian Mainline LDC Settlement and Supplemental Agreement can be found in the *General developments of the business – Natural Gas Pipelines – Developments in the Canadian Natural Gas Pipelines Segment – Canadian Mainline Settlement* section above. In addition, the NGTL System concluded its two-year settlement arrangement in 2017 and is currently working with interested parties for a new arrangement for 2018 and longer.

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 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 are considered *natural gas companies* operating under the provisions of the *Natural Gas Act of 1938* and the *Natural Gas Policy Act of 1978*, and are 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.

TransCanada holds certificates of public convenience and necessity issued by the FERC, authorizing us to operate pipelines, facilities and properties now in operation and to transport and store natural gas in interstate commerce. Our regulated natural gas storage business also has facilities that are regulated by the FERC. The Company is also subject to the *Natural Gas Pipeline Safety Act of 1968* and the *Pipeline Safety Improvement Act of 2002*, which regulate the safety of natural gas pipelines.

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 (CRE) 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 6,100 MW of operating generation capacity that we own, and approximately 900 MW of generation capacity under development. Our power generation assets are located in Alberta, Ontario, Québec, New Brunswick and Arizona, and are powered by natural gas, nuclear, and wind. A substantial 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.

Our U.S. Northeast power generation assets were sold in second quarter 2017, and 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. The transaction is expected to close in first quarter 2018, subject to regulatory and other approvals.

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 6,779employees, 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)	2,530
Western Canada (excluding Calgary)	547
Eastern Canada	319
Houston (includes Canadian employees working in the U.S.)	759
U.S. Midwest	708
U.S. Northeast	277
U.S. Southeast/ Gulf Coast (excluding Houston)	1,296
U.S. West Coast	75
Mexico	268
Total	6,779

CORPORATE RESTRUCTURING AND BUSINESS TRANSFORMATION

In mid-2015, we commenced a business restructuring and transformation initiative. While there is no change to our corporate strategy, we undertook this 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 AND ENVIRONMENTAL PROTECTION AND SOCIAL POLICIES

The Health, Safety and Environment (HSE) committee of the Board oversees operational risk, people and process safety, security of personnel and environmental risks, and monitors compliance with our HSE programs 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 HSE committee reviews HSE performance and operational risk management. It receives detailed reports on:

- overall HSE 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.

The HSE 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 – Risks and Risk Management – Health, safety and environment* section, which section of the MD&A is incorporated by reference herein. Generally, each year the committee or the committee Chair tours one of our existing assets or projects under development as part of its responsibility to monitor and review our HSE practices. Additionally, the Board and the 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 energy and pipeline infrastructure, is a top priority. All new assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are brought 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, including risks related to climate change. 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, but not limited to, 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, the imposition of remedial requirements and/or the issuance of orders respecting future operations.

Through the implementation of our Environment Program, we continually monitor our facilities to ensure compliance with all environmental requirements. We routinely monitor the 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 policies, guiding principles and practices in place to help manage Indigenous and stakeholder relations. We have adopted a Code of Business Ethics (Code) which applies to all employees, officers and directors as well as contract workers 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 the Code.

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 – Natural Gas Pipelines – Business risks, Liquids Pipelines – Business risks, Energy – Business risks* and *Other information – Risks and 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 to which TCPL is a party restrict TCPL's ability to declare and pay dividends to TransCanada under certain circumstances and, if such restrictions apply, they may, in turn, have an impact on our ability to declare and pay dividends. 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. Further information about such trust notes can be found in the *Financial condition – Junior subordinated notes issued* section of the MD&A, which section of the MD&A is incorporated by reference herein. In the opinion of TransCanada's management, such provisions do not currently restrict TransCanada's ability to declare or pay dividends.

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, 2018, are set out in the MD&A under the heading *About our business – 2017 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 and make optional cash payments 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 Toronto Stock Exchange (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 percent, 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 stable outlook, S&P has assigned a long-term corporate credit rating of A- with a negative 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	A-	A-	A (low)
Medium-term notes	A3	A-	A-	A (low)
TCPL - Junior subordinated notes	Baa1	BBB	BBB	BBB
TransCanada Trust - Subordinated trust notes	Baa2	BBB	BBB	Not rated
TransCanada Corporation - Preferred shares	Not Rated	P-2	BBB	Pfd-2 (low)
Commercial paper (U.S.) (TCPL and TCPL guaranteed)	P-2	A-2	F2	Not rated
Commercial paper (Canadian) (TCPL and TCPL guaranteed)	P-2	Not Rated	F2	R-1 (low)
Trend/ rating outlook	Stable	Negative	Stable	Stable

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

Each of the Company, TCPL, TransCanada Trust and 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, and 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 and Baa2 ratings assigned to TCPL's junior subordinated notes and to the TransCanada Trust subordinated trust notes, respectively, 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 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 the obligor's capacity to meet its financial commitment is strong; however, the obligation is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rated categories. TCPL's and TCPL guaranteed U.S. commercial paper programs are each rated A-2 which is the second highest of six rating categories for short-term debt issuers. Short-term debt issuers rated A-2 have satisfactory capacity to meet their financial commitments, however they are somewhat more susceptible to adverse effects of changes in circumstances and economic conditions than obligors in the higher rating 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. The P-2 rating assigned to TransCanada's preferred shares is the second highest of eight rating categories for Canadian preferred shares. There is a direct correspondence between the specific ratings assigned on S&P's Canadian preferred share ratings scale and the global debt ratings scale. The BBB and P-2 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.

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 considered strong; however, the obligation is 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 U.S. 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 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. The BBB ratings assigned to TransCanada's preferred shares, TCPL's junior subordinated notes and the TransCanada Trust subordinated trust notes indicate that expectations of default risk are currently 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 ten 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 ten 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 ten 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 New York Stock Exchange (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 2017	$63.29	$60.61	$61.18	27,863,394	$49.26	$47.70	$48.64	16,561,792
November 2017	$65.18	$60.80	$61.88	33,552,507	$51.07	$47.38	$48.03	25,361,655
October 2017	$63.40	$59.23	$61.25	25,907,314	$50.65	$46.24	$47.48	19,148,833
September 2017	$63.42	$60.61	$61.67	30,997,671	$51.85	$49.14	$49.43	16,885,509
August 2017	$65.11	$61.59	$63.41	23,489,338	$51.77	$48.88	$50.80	16,106,392
July 2017	$64.81	$61.19	$63.70	25,912,413	$51.81	$47.06	$51.12	20,227,907
June 2017	$64.35	$61.32	$61.82	37,258,302	$48.49	$46.42	$47.67	41,976,981
May 2017	$64.69	$61.33	$62.71	31,563,490	$47.73	$45.07	$46.45	23,775,659
April 2017	$64.40	$60.78	$63.38	28,179,483	$48.20	$45.38	$46.44	15,720,604
March 2017	$62.80	$60.54	$61.37	43,585,590	$47.02	$45.16	$46.15	23,525,317
February 2017	$62.88	$60.35	$61.06	34,410,621	$48.29	$45.75	$45.99	18,004,202
January 2017	$65.24	$60.28	$61.39	30,801,086	$49.77	$44.90	$47.22	22,301,648

TransCanada Corporation ATM Issuance Program

In June 2017, we established an at-the-market (ATM) distribution 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 U.S. The ATM program, which is effective for a 25-month period, will be utilized as appropriate to manage our capital structure over time. Further information about the ATM program can be found in the *Financial condition – TransCanada Corporation ATM issuance 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 2017											
High	$ 20.40	$ 19.75	$ 16.43	$ 16.09	$ 17.45	$ 17.43	$ 23.04	$ 23.73	$ 24.50	$ 26.75	$ 26.21
Low	$ 19.48	$ 18.69	$ 15.70	$ 15.23	$ 16.57	$ 16.64	$ 22.15	$ 22.50	$ 23.85	$ 26.27	$ 25.75
Close	$ 20.11	$ 19.72	$ 16.43	$ 15.61	$ 17.20	$ 16.90	$ 22.65	$ 23.46	$ 24.50	$ 26.66	$ 26.15
Volume traded	107,740	95,907	92,605	91,082	160,152	63,363	205,651	137,985	116,915	594,841	296,027
November 2017											
High	$ 20.92	$ 20.20	$ 16.60	$ 16.30	$ 17.57	$ 17.45	$ 23.15	$ 23.34	$ 24.80	$ 27.05	$ 26.65
Low	$ 20.13	$ 19.50	$ 16.19	$ 15.64	$ 16.90	$ 16.86	$ 22.75	$ 22.76	$ 23.94	$ 26.59	$ 26.16
Close	$ 20.56	$ 19.77	$ 16.30	$ 15.82	$ 17.53	$ 17.35	$ 22.99	$ 23.30	$ 24.35	$ 26.63	$ 26.22
Volume traded	69,727	87,507	63,309	39,835	196,487	37,104	295,310	532,773	123,619	817,319	711,368
October 2017											
High	$ 20.44	$ 20.49	$ 16.66	$ 16.50	$ 17.40	$ 17.37	$ 23.19	$ 23.25	$ 24.57	$ 26.90	$ 26.15
Low	$ 20.00	$ 19.70	$ 15.80	$ 15.40	$ 16.75	$ 16.49	$ 22.01	$ 22.34	$ 23.95	$ 26.60	$ 25.94
Close	$ 20.43	$ 20.09	$ 16.49	$ 15.80	$ 17.20	$ 17.00	$ 23.00	$ 23.23	$ 24.04	$ 26.72	$ 26.15
Volume traded	110,739	216,388	114,783	42,806	552,356	24,562	210,297	189,813	174,291	915,285	1,109,588
September 2017											
High	$ 20.21	$ 20.25	$ 16.01	$ 15.80	$ 16.89	$ 16.75	$ 22.52	$ 22.55	$ 24.34	$ 26.79	$ 26.10
Low	$ 19.02	$ 19.28	$ 15.00	$ 15.00	$ 16.01	$ 16.40	$ 21.75	$ 22.03	$ 23.72	$ 26.35	$ 25.70
Close	$ 20.01	$ 20.05	$ 15.93	$ 15.50	$ 16.81	$ 16.58	$ 22.19	$ 22.35	$ 24.00	$ 26.56	$ 25.95
Volume traded	113,495	52,001	308,974	29,751	391,934	6,989	326,801	421,503	348,017	632,004	836,498
August 2017											
High	$ 20.36	$ 20.50	$ 15.97	$ 15.84	$ 17.16	$ 17.05	$ 22.85	$ 23.31	$ 24.89	$ 27.07	$ 26.25
Low	$ 19.09	$ 19.28	$ 15.05	$ 15.00	$ 16.19	$ 16.24	$ 21.40	$ 21.66	$ 23.56	$ 26.50	$ 24.74
Close	$ 19.50	$ 19.39	$ 15.19	$ 15.05	$ 16.44	$ 16.50	$ 22.39	$ 22.40	$ 23.81	$ 26.78	$ 25.99
Volume traded	108,599	42,106	39,245	41,059	107,413	18,991	445,621	185,971	77,702	838,430	791,083
July 2017											
High	$ 20.60	$ 20.75	$ 15.98	$ 15.68	$ 17.22	$ 17.22	$ 22.87	$ 23.25	$ 24.97	$ 27.19	$ 26.28
Low	$ 19.32	$ 19.15	$ 14.87	$ 14.42	$ 15.99	$ 15.60	$ 22.10	$ 22.36	$ 24.06	$ 26.75	$ 25.86
Close	$ 20.36	$ 20.70	$ 15.92	$ 15.68	$ 17.13	$ 17.03	$ 22.73	$ 23.20	$ 24.85	$ 26.94	$ 26.22
Volume traded	388,352	60,358	169,375	23,750	162,582	12,217	1,054,905	212,533	70,480	721,215	498,610
June 2017											
High	$ 19.49	$ 19.30	$ 15.00	$ 14.52	$ 16.22	$ 15.84	$ 22.27	$ 22.49	$ 24.50	$ 27.23	$ 26.40
Low	$ 17.81	$ 17.69	$ 13.86	$ 13.20	$ 14.98	$ 14.83	$ 20.00	$ 20.25	$ 22.50	$ 26.51	$ 25.85
Close	$ 19.49	$ 19.17	$ 14.96	$ 14.44	$ 16.06	$ 15.60	$ 22.17	$ 22.40	$ 24.42	$ 26.99	$ 26.21
Volume traded	300,355	176,734	167,884	69,863	161,550	51,256	559,961	370,252	112,731	354,415	498,096
May 2017											
High	$ 19.19	$ 19.24	$ 14.87	$ 14.10	$ 15.85	$ 15.50	$ 21.70	$ 22.19	$ 23.69	$ 27.33	$ 26.30
Low	$ 18.32	$ 18.18	$ 14.14	$ 13.43	$ 15.34	$ 15.00	$ 20.51	$ 20.85	$ 22.51	$ 26.65	$ 25.81
Close	$ 18.33	$ 18.41	$ 14.36	$ 13.43	$ 15.69	$ 15.01	$ 20.60	$ 22.86	$ 22.80	$ 26.75	$ 26.08
Volume traded	77,511	173,915	127,101	62,880	134,603	40,390	466,568	171,850	275,647	270,212	628,148
April 2017											
High	$ 19.87	$ 19.44	$ 15.08	$ 14.37	$ 16.57	$ 15.55	$ 22.49	$ 22.85	$ 24.34	$ 27.42	$ 26.48
Low	$ 19.06	$ 18.68	$ 14.40	$ 13.70	$ 15.55	$ 15.27	$ 21.43	$ 21.94	$ 23.65	$ 26.62	$ 25.92
Close	$ 19.07	$ 18.89	$ 14.41	$ 13.80	$ 15.60	$ 15.39	$ 21.55	$ 22.10	$ 23.65	$ 27.28	$ 26.27
Volume traded	291,423	341,202	319,778	163,112	145,831	8,965	369,494	449,997	146,307	181,851	1,103,086
March 2017											
High	$ 19.65	$ 19.04	$ 15.17	$ 13.78	$ 16.25	$ 15.54	$ 22.40	$ 23.16	$ 23.92	$ 26.77	$ 26.18
Low	$ 18.30	$ 17.54	$ 14.30	$ 12.99	$ 15.59	$ 14.50	$ 21.70	$ 22.35	$ 22.86	$ 26.37	$ 25.61
Close	$ 19.40	$ 18.90	$ 14.67	$ 13.72	$ 15.92	$ 15.54	$ 22.37	$ 22.58	$ 23.90	$ 26.71	$ 26.00
Volume traded	276,109	294,227	218,414	76,900	156,735	5,348	304,622	455,353	98,207	527,184	1,048,057
February 2017											
High	$ 18.99	$ 18.13	$ 14.99	$ 13.47	$ 16.31	$ 15.39	$ 22.37	$ 23.10	$ 23.94	$ 26.64	$ 25.90
Low	$ 17.59	$ 16.50	$ 14.00	$ 12.60	$ 15.19	$ 14.75	$ 20.36	$ 21.30	$ 22.74	$ 26.37	$ 25.46
Close	$ 18.32	$ 17.84	$ 14.48	$ 13.10	$ 16.00	$ 14.75	$ 22.01	$ 22.74	$ 23.05	$ 26.48	$ 25.73
Volume traded	139,957	97,323	205,242	140,335	152,188	3,163	249,246	275,553	247,326	234,969	1,750,501
January 2017											
High						$ 14.76					
Low	$ 17.82	$ 17.25	$ 14.60	$ 13.40	$ 15.54	$ 13.10	$ 20.75	$ 21.51	$ 23.52	$ 26.85	$ 25.92
Close	$ 15.78	$ 15.02	$ 13.19	$ 11.96	$ 13.78	$ 14.76	$ 18.62	$ 19.51	$ 22.01	$ 26.28	$ 25.32
Volume traded	$ 17.61	$ 16.81	$ 14.35	$ 13.11	$ 15.29	12,495	$ 20.42	$ 21.39	$ 22.80	$ 26.60	$ 25.45
	234,433	108,774	304,127	68,818	301,751		1,226,439	806,021	132,391	529,655	4,283,769

Directors and officers

As of February 14, 2018, the directors and officers of TransCanada as a group beneficially owned, or exercised control or direction over, directly or indirectly, an aggregate of 588,310 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 14, 2018 (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 Heritage Point, Alberta Canada	Corporate director. Director, Winter Sport Institute (non-profit) since February 2015. Director, Calgary Airport Authority from January 2010 to December 2013.	2005
Derek H. Burney, O.C. Ottawa, Ontario Canada	Senior strategic advisor, Norton Rose Fulbright (law firm). Chairman, GardaWorld International Advisory Board (risk management and security services) since April 2008. Advisory Board member, Paradigm Capital Inc. (investment dealer) since May 2011. Director (Chair), Liquor Stores N.A. Ltd. since June 2017.	2005
Stéphan Crétier Dubai, United Arab Emirates	Chairman, President and Chief Executive Officer of Garda World Security Corporation (Garda World) (private security services) and director of a number of Garda World's direct and indirect subsidiaries, since 1999. Director, ORTHOsoft Inc. (formerly ORTHOsoft Holdings Inc.) (medical software technology) from August 2004 to November 2004. Director, BioEnvelop Technologies Corp. (manufacturing) from 2001 to 2003. Director, President and Chief Executive Officer, Rafale Capital Corp. (manufacturing) from 1999 to 2001.	2017
Russell K. Girling[1] Calgary, Alberta Canada	President and Chief Executive Officer, TransCanada since July 2010. Chief Operating Officer from July 2009 to June 2010, and President, Pipelines from June 2006 to June 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. (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
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.	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. Director, United States Enrichment Corporation (basic materials, nuclear) from December 2011 to October 2012.	2013
Indira Samarasekera Vancouver, British Columbia Canada	Senior Advisor, Bennett Jones LLP (law firm) since September 2015. 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. Director, C&C Energia Ltd. (oil and gas) from May 2010 to December 2012.	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, 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 infrastucture Inc. since 2015. Director, Royal Bank of Canada (chartered bank) since 2015. Member, International Advisory Board of École des Hautes Etudes Commerciales Montréal from 2006 to October 2017.	2017[2]
Richard E. Waugh Calgary, Alberta Canada	Corporate director. Advisor, Acasta Enterprises Inc. (asset management/investment) since June 2015. President and Chief Executive Officer, Scotiabank from March 2003 to November 2013 and Deputy Chairman from November 2013 to January 2014. Director, Catalyst Inc. (non-profit) from February 2007 to November 2013 and Chair, Canadian Advisory Board, Catalyst Canada Inc. from February 2007 to October 2013.	2012

Notes:
(1) 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.
(2) Effective November 6, 2017.

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.

Canwest Global Communications Corp. voluntarily entered into the *Companies' Creditors Arrangement Act* (CCAA) and obtained an order from the Ontario Superior Court of Justice to start proceedings on October 6, 2009. Although no cease trade orders were issued, Canwest shares were de-listed by the TSX after the filing and started trading on the TSX Venture Exchange. Canwest emerged from CCAA protection and Postmedia Network acquired its newspaper business on July 13, 2010 while Shaw Communications Inc. acquired its broadcast media business on October 27, 2010. Mr. Burney was a director of Canwest from April 2005 to October 2010.

Laricina Energy (Laricina) voluntarily entered into the 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.

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 and Environment committee and the Human Resources committee. The voting members of each of these committees, as of February 14, 2018 (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 & Environment committee	Human Resources committee
Kevin E. Benson	ü	Chair		
Derek H. Burney	ü	ü		
Stéphan Crétier	ü		ü	
S. Barry Jackson		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	
Richard E. Waugh			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	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	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 1, 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 and President, Liquids Pipelines	Prior to March 2014, Senior Vice-President, Oil Pipelines.
Dean C. Patry	Senior Vice-President, Liquids Pipelines	Prior to November 2017, Senior Vice-President, Liquids Pipelines (TCPL). Prior to February 2017, Senior Vice-President, Business Transformation (TCPL). Prior to October 2015, Vice-President, Major Projects Development (TCPL). Prior to July 2014, Vice-President, U.S. Natural Gas Pipelines Central (TCPL). Prior to March 2014, Vice-President, U.S. Pipelines Central (TCPL).
Francois L. Poirier	Executive Vice-President, Strategy and Corporate Development	Prior to February 1, 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	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.

Corporate officers

Name	Present position held	Principal occupation during the five preceding years
Sean M. Brett	Vice-President, Risk Management	Prior to August 2015, Vice-President and Treasurer.
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 (TCPL).
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. Prior to March 2012, Vice-President, Finance Law.
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. The Code 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.

Our Code 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 14, 2018 are John E. Lowe (Chair), Kevin E. Benson, Derek H. Burney, Stéphan Crétier, Indira Samarasekera, D. Michael G. Stewart and Thierry Vandal. Mr. Vandal joined the committee effective November 8, 2017.

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, Mr. Benson 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 Agrium Inc. and DCP Midstream LLC. He has also held various executive and management positions with ConocoPhillps for more than 25 years.

Kevin E. Benson

Mr. Benson is a Chartered Accountant (South Africa) and was a member of the South African Society of Chartered Accountants. He serves as a director of the Winter Sport Institute, and was the President and Chief Executive Officer of Laidlaw International, Inc. until October 2007. In prior years, he has held several executive positions including as President and Chief Executive Officer of The Insurance Corporation of British Columbia and has served on other public company boards and on the audit committees of all of those boards.

Derek H. Burney

Mr. Burney earned a Bachelor of Arts (Honours) and Master of Arts from Queen’s University. He is currently a senior strategic advisor at Norton Rose Fulbright. He has also been the Chairman of GardaWorld's International Advisory Board since April 2008, a member of the Paradigm Capital Inc. Advisory Board since May 2011, and has served as Chair of the board of directors of Liquor Stores N.A. Ltd. since June 2017. He previously served as President and Chief Executive Officer of CAE Inc. and as Chair and Chief Executive Officer of Bell Canada International Inc. Mr. Burney was the lead director at Shell Canada Limited from April 2001 until May 2007 and was the Chair of Canwest Global Communications Corp. from August 2006 until October 2010. He has served on one other organization’s audit committee and has participated in Financial Reporting Standards Training offered by KPMG.

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. 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.

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 the Bank of Nova Scotia, Magna International Inc.,

Asia-Pacific Foundation, and the Rideau Hall Foundation. 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.

D. Michael G. Stewart

Mr. Stewart earned a Bachelor of Science in Geological Sciences with First Class Honours from Queen's University. He currently serves on the board of directors of Pengrowth Energy Corporation and CES Energy Solutions Corp. He has also previously served on the board of directors of several other public companies and organizations and was on the audit committee and the Chair of the audit committee of certain of those boards. Mr. Stewart held a number of senior executive positions with Westcoast Energy Inc. including Executive Vice-President, Business Development. He has been active in the Canadian energy industry for over 40 years.

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 the Royal Bank of Canada (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)	2017	2016
Audit fees	$9.7(1)	$8.2
• audit of the annual consolidated financial statements		
• services related to statutory and regulatory filings or engagements		
• review of interim consolidated financial statements and information contained in various prospectuses and other securities offering documents		
Audit-related fees	$0.1	$0.1
• services related to the audit of the financial statements of certain TransCanada post-retirement and post-employment plans, and pipeline abandonment trusts		
Tax fees(2)	$0.8	$0.6
• 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	–
• French translation services		
Total fees	**$10.8**	**$8.9**

Notes:
(1) The increase in audit fees from 2016 reflects the transfer of the Columbia audit to KPMG, following TransCanada's acquisition of Columbia in 2016.
(2) The tax fees principally related to fees incurred on account of compliance matters.

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

Other than as disclosed in the MD&A, which is incorporated by reference herein, TransCanada did not enter into any material contracts outside the ordinary course of business during the year ended December 31, 2017, nor has it entered into any material contracts outside the ordinary course of business prior to the year ended December 31, 2017 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

AFUDC	Allowance of funds used during construction
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
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
investment base	Includes rate base as well as assets under construction
LDC	Local distribution company
LNG	Liquefied natural gas
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	Our annual average investment used
WCSB	Western Canada Sedimentary Basin
Year End	Year ended December 31, 2017

Accounting terms

AFUDC	Allowance for funds used during construction
DRP	Dividend reinvestment plan
GAAP	U.S. generally accepted accounting principles
OM&A	Operating, maintenance & administration
ROE	Rate of return on common equity

Government and regulatory bodies terms

AER	Alberta Energy Regulator
BCEAO	Environmental Assessment Office (British Columbia)
CCAA	*Companies' Creditors Arrangement Act*
CBCA	*Canada Business Corporations Act*
CFE	Comisión Federal de Electricidad (Mexico)
CRE	Comisión Reguladora de Energía (Mexico)
CQDE	Québec Environmental Law Centre/ Centre québécois du droit de l'environnement
DOS	U.S. Department of State
FERC	Federal Energy Regulatory Commission (U.S.)
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	Nebraska Public Service Commission
PUC	Public Utilities Commission
SEC	U.S. Securities and Exchange Commission
SGER	Specified Gas Emitters Regulations
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 14, 2018

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, 2017.

This MD&A should be read with our accompanyingDecember 31, 2017 audited consolidated financial statements and notes for the same period, which have been prepared in accordance with U.S. generally accepted accounting principles (GAAP).

Contents

ABOUT THIS DOCUMENT **6**

ABOUT OUR BUSINESS **10**

- Three core businesses 11
- Our strategy 12
- Impact of U.S. Tax Reform 13
- 2016 Acquisition of Columbia Pipeline Group, Inc. 14
- Capital program 15
- 2017 Financial highlights 17
- Outlook 23

NATURAL GAS PIPELINES BUSINESS **24**

CANADIAN NATURAL GAS PIPELINES **31**

U.S. NATURAL GAS PIPELINES **35**

MEXICO NATURAL GAS PIPELINES **40**

NATURAL GAS PIPELINES BUSINESS RISKS **43**

LIQUIDS PIPELINES **45**

ENERGY **55**

CORPORATE **65**

FINANCIAL CONDITION **70**

OTHER INFORMATION **83**

- Risks and risk management 83
- Controls and procedures 90
- Critical accounting estimates 91
- Financial instruments 94
- Accounting changes 97
- Reconciliation of comparable EBITDA and comparable EBIT to segmented earnings 100
- Quarterly results 101

GLOSSARY **108**

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 108. All information is as of February 14, 2018 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:

- planned changes in our business
- our financial and operational performance, including the performance of our subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows and future financing options available to us
- expected dividend growth
- expected costs for planned projects, including projects under construction, permitting and in development
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future accounting changes, commitments and contingent liabilities
- the expected impact of U.S. Tax Reform
- 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

- planned wind-down of our U.S. Northeast power marketing business
- inflation rates and commodity prices
- nature and scope of hedging
- regulatory decisions and outcomes
- interest, tax and foreign exchange rates, including the impact of U.S. Tax Reform
- planned and unplanned outages and the use of our pipeline and energy assets
- integrity and reliability of our assets
- access to capital markets
- anticipated construction costs, schedules and completion dates.

Risks and uncertainties

- our ability to successfully implement our strategic priorities and whether they will yield the expected benefits
- the operating performance of our pipeline and energy assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the availability and price of energy commodities
- the amount of capacity payments and revenues from our energy business
- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration and insurance claims
- performance and credit risk of our counterparties
- changes in market commodity prices
- changes in the political environment
- changes in environmental and other laws and regulations
- competitive factors in the pipeline and energy sectors
- construction and completion of capital projects
- costs for labour, equipment and materials
- access to capital markets
- interest, tax and foreign exchange rates, including the impact of U.S. Tax Reform
- weather
- cyber security
- technological developments
- economic conditions in North America as well as globally.

You can read more about these factors and others in 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 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 earnings
- comparable earnings per common share
- comparable EBITDA
- comparable EBIT
- 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 similar to measures presented by other entities.

Comparable measures

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. 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 and changes 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 equivalent GAAP measures.

Comparable measure	Original measure
comparable earnings	net income/(loss) attributable to common shares
comparable earnings per common share	net income/(loss) per common share
comparable EBITDA	segmented earnings
comparable EBIT	segmented earnings
comparable funds generated from operations	net cash provided by operations
comparable distributable cash flow	net cash provided by operations

Comparable earnings and comparable earnings per share

Comparable earnings represents earnings or loss 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 and non-controlling interests adjusted for the specific items. See the Financial highlights section for a reconciliation of net income/(loss) attributable to common shares and net income/(loss) per common share.

Comparable EBIT and comparable EBITDA

Comparable EBIT represents segmented earnings adjusted for the specific items described above. We use comparable EBIT as a measure of our earnings from ongoing operations as it is a useful measure of our performance and an effective tool for evaluating trends in each segment. Comparable EBITDA is calculated the same way as comparable EBIT but excludes the non-cash charges for depreciation and amortization. See the Other information section for a reconciliation to segmented earnings.

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. See the Financial condition section for a reconciliation to net cash provided by operations.

Comparable distributable cash flow and comparable distributable cash flow per share

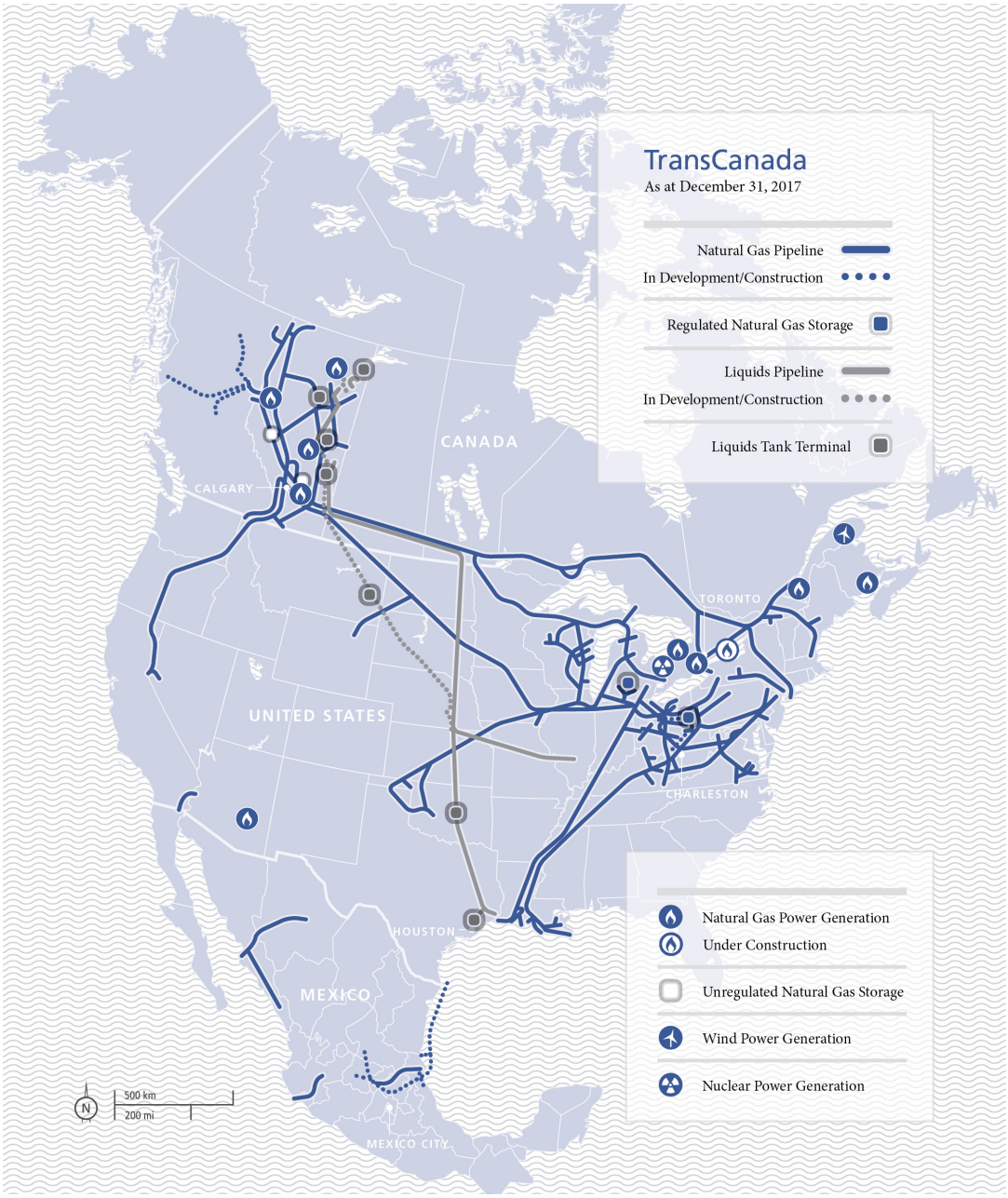
We believe comparable distributable cash flow is a useful supplemental measure of performance that defines cash available to common shareholders before capital allocation. Comparable distributable cash flow is defined as comparable funds generated from operations less preferred share dividends, distributions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

Although we deduct maintenance capital expenditures in determining comparable distributable cash flow, we have the ability to recover the majority of these costs in Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Liquids Pipelines. Canadian natural gas pipelines maintenance capital expenditures are reflected in rate bases, on which we earn a regulated return and subsequently recover in tolls. The majority of our U.S. natural gas pipelines can seek to recover maintenance capital expenditures through rates established in future rate cases or rate settlements. As such, these maintenance capital expenditures are effectively recovered in the same manner as expansion capital expenditures. Tolling arrangements in Liquids Pipelines provide for recovery of maintenance capital.

Effective December 31, 2017, we amended our presentation of comparable distributable cash flow and comparable distributable cash flow per share to illustrate the impact of excluding recoverable maintenance capital expenditures from their respective calculations. We have included comparable distributable cash flow and comparative distributable cash flow per share for 2016 and 2015 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 business are made and how performance of our business 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 non-operational Corporate segment consisting of corporate and administrative functions that provide governance and other support to our operational business segments.

Year at a glance

at December 31 (millions of $)	2017	2016
Total assets		
Canadian Natural Gas Pipelines	**16,904**	15,816
U.S. Natural Gas Pipelines	**35,898**	34,422
Mexico Natural Gas Pipelines	**5,716**	5,013
Liquids Pipelines	**15,438**	16,896
Energy[1]	**8,503**	13,169
Corporate	**3,642**	2,735
	86,101	88,051

1 2016 includes U.S. Northeast power assets held for sale.

year ended December 31 (millions of $)	2017	2016
Total revenues		
Canadian Natural Gas Pipelines	**3,693**	3,682
U.S. Natural Gas Pipelines[1]	**3,584**	2,526
Mexico Natural Gas Pipelines	**570**	378
Liquids Pipelines	**2,009**	1,755
Energy[2]	**3,593**	4,206
	13,449	12,547

1 Includes Columbia effective July 2016.
2 Includes U.S. Northeast power and Ontario solar assets until sold in 2017.

year ended December 31 (millions of $)	2017	2016
Comparable EBITDA		
Canadian Natural Gas Pipelines	**2,144**	2,182
U.S. Natural Gas Pipelines[1]	**2,357**	1,682
Mexico Natural Gas Pipelines	**519**	332
Liquids Pipelines	**1,348**	1,152
Energy[2]	**1,030**	1,281
Corporate	**(21)**	18
	7,377	6,647

1 Includes Columbia effective July 2016.
2 Includes U.S. Northeast power and Ontario solar assets until sold in 2017.

OUR STRATEGY

Our energy infrastructure business is made up of pipeline 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 long-life 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 $47 billion capital program, comprised of $23 billion in near-term projects and $24 billion in commercially-supported medium to long-term projects. These will contribute incremental earnings and cash flow over the near, medium and long terms as our investments 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 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.

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 management to ensure we provide maximum shareholder value over the short, medium and long terms.

A competitive advantage

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

- Strong leadership: scale, presence, operating capabilities and strategy development; expertise in regulatory, legal, commercial and financing support.
- High quality portfolio: 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 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 dividend on our common shares 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.

U.S. TAX REFORM

On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act (U.S. Tax Reform or the Act) 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 of this change, we have remeasured existing deferred income tax assets and deferred income tax liabilities related to our U.S. businesses to reflect the new lower income tax rate as at December 31, 2017.

For our businesses in the U.S. not subject to rate-regulated accounting (RRA), the reduction in enacted tax rates has been recorded as a decrease in net deferred income tax liabilities and income tax expense, resulting in an increase in net income attributable to common shares for the year ended December 31, 2017 in the amount of $816 million.

For our businesses in the U.S. subject to RRA, we expect the lower income tax rates to impact future rate setting processes and have therefore recognized a net regulatory liability with a corresponding reduction in net deferred income tax liabilities in the amount of $1,686 million. These regulatory liabilities will be amortized to earnings over time.

Net deferred income tax liabilities related to the cumulative remeasurements of employee post-retirement benefits included in accumulated other comprehensive income have also been adjusted with a corresponding increase in deferred income tax expense of $12 million.

Given the significance of the legislation, the SEC issued guidance which allows registrants to record provisional amounts which may be adjusted as information becomes available, prepared or analyzed during a measurement period not to exceed one year.

The SEC guidance summarizes 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 tax laws in effect prior to the enactment of the Act.

At December 31, 2017, we consider all amounts recorded related to U.S. Tax Reform to be reasonable estimates. Amounts related to businesses subject to RRA are provisional as our interpretation, assessment and presentation of the impact of the tax law change may be further clarified with additional guidance from regulatory, tax and accounting authorities. Should additional guidance be provided by these authorities or other sources during the one-year measurement period, we will review the provisional amounts and adjust as appropriate.

As a result of the lower U.S. income tax rates included as part of the Act, we expect a modest increase to 2018 earnings. In addition to the reduction in statutory rates, longer-term there are several other provisions in the new legislation which may impact us prospectively, including changes to the expensing of depreciable property, limitations to interest deductions, the creation of Base Erosion Anti-Abuse Tax along with certain exemptions for rate-regulated businesses. We continue to evaluate the impact of these and other provisions of the Act.

2016 ACQUISITION OF COLUMBIA PIPELINE GROUP, INC.

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, were exchanged into 96.6 million TransCanada common shares.

At the date of acquisition, Columbia operated approximately 24,500 km (15,200 miles) of regulated natural gas pipelines, 285 Bcf of natural gas storage facilities and related midstream assets. We acquired Columbia to expand our natural gas business in the U.S. market, positioning ourselves for additional long-term growth opportunities. The acquisition also included a large portfolio of new capital growth projects including seven significant pipeline expansions designed to transport growing supply from the Marcellus/Utica production basins to markets, as well as a scheduled program for modernization of existing infrastructure through 2020 to ensure the continuation of a safe, reliable and efficient system.

While Columbia Pipeline Group, Inc. was the overall corporate entity we acquired, we now make reference to specific businesses obtained through the acquisition including: Columbia Gas, Columbia Gulf, Millennium, Crossroads, Midstream and Columbia Storage.

As part of the financing plan for the Columbia acquisition, we announced the planned monetization of our U.S. Northeast power business, including our U.S. Northeast power marketing business. Subsequently, we issued additional common shares to support the permanent financing of the acquisition and announced an agreement to acquire all of the outstanding publicly held common units of Columbia Pipeline Partners LP (CPPL).

Common shares and subscription receipts issued under public offerings

On April 1, 2016, we issued 96.6 million subscription receipts entitling each holder to receive one common share upon closing of the Columbia acquisition to partially fund the Columbia acquisition at a price of $45.75 each for gross proceeds of $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.

On November 16, 2016, we issued 60.2 million common shares at a price of $58.50 each for gross proceeds of approximately $3.5 billion. Proceeds from the offering were used to repay a portion of the US$6.9 billion acquisition bridge facilities which were drawn to partially finance the closing of the Columbia acquisition.

Columbia Pipeline Partners LP

In February 2017, we completed the acquisition, for cash, of all outstanding publicly held common units of CPPL for an aggregate transaction value of US$921 million. See the U.S. Natural Gas Pipelines Significant events section for further information.

Monetization of U.S. Northeast power business

In April 2017, we closed the sale of TC Hydro for US$1.07 billion, before post-closing adjustments, and in June 2017, we closed the sale of Ravenswood, Ironwood, Ocean State Power and Kibby Wind for US$2.029 billion, before post-closing adjustments. Proceeds from these sales were used to fully retire the remaining bridge facilities that partially funded the acquisition of Columbia.

In December 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. The transaction is expected to close in the first quarter of 2018 subject to regulatory and other approvals.

See the Energy Significant events section for further information.

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 flow.

Our capital program consists of approximately $23 billion of near-term projects and approximately $24 billion of commercially supported medium to longer-term projects. Amounts presented exclude maintenance capital expenditures, capitalized interest and AFUDC.

All projects are subject to cost adjustments due to market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits.

Near-term projects

(billions of $)	Expected in-service date	Estimated project cost	Carrying value at December 31, 2017
Canadian Natural Gas Pipelines			
Canadian Mainline	2018 - 2021	0.2	—
NGTL System	2018	0.6	0.2
	2019	2.3	0.3
	2020	1.6	0.1
	2021	2.7	—
U.S. Natural Gas Pipelines			
Columbia Gas			
Leach XPress[1]	2018	US 1.6	US 1.5
WB XPress	2018	US 0.8	US 0.4
Mountaineer XPress	2018	US 2.6	US 0.5
Modernization II	2018 - 2020	US 1.1	US 0.1
Buckeye XPress	2020	US 0.2	—
Columbia Gulf			
Cameron Access	2018	US 0.3	US 0.3
Gulf XPress	2018	US 0.6	US 0.2
Other[2]	2018 - 2020	US 0.3	—
Mexico Natural Gas Pipelines			
Sur de Texas[3]	2018	US 1.3	US 1.0
Villa de Reyes	2018	US 0.8	US 0.5
Tula	2019	US 0.7	US 0.5
Liquids Pipelines			
White Spruce	2019	0.2	—
Energy			
Napanee	2018	1.3	0.9
Bruce Power – life extension[4]	up to 2020	0.9	0.3
		20.1	**6.8**
Foreign exchange impact on near-term projects[5]		**2.6**	**1.3**
Total near-term projects (billions of Cdn$)		**22.7**	**8.1**

1 Leach XPress was placed in service in January 2018.
2 Reflects our proportionate share of costs related to Portland Xpress and various expansion projects.
3 Our proportionate share.
4 Amount reflects our proportionate share of the remaining capital costs that Bruce Power expects to incur on its life extension investment programs in advance of the Unit 6 major refurbishment outage which is expected to begin in 2020.
5 Reflects U.S./Canada foreign exchange rate of 1.25 at December 31, 2017.

Medium to longer-term projects

The medium to longer-term projects have greater uncertainty with respect to timing and estimated project costs. The expected in-service dates of these projects are post-2020, and costs provided in the schedule below reflect the most recent costs for each project as filed with the applicable regulatory authorities or otherwise determined. These projects are subject to approvals that include FID and/or complex regulatory processes; however, each project has commercial support except where noted. Please refer to each business segment's Significant events section for further information on these projects.

(billions of $)	Segment	Estimated project cost	Carrying value at December 31, 2017
Heartland and TC Terminals[1]	Liquids Pipelines	0.9	0.1
Grand Rapids Phase 2[2]	Liquids Pipelines	0.7	—
Bruce Power – life extension[2]	Energy	5.3	—
Keystone projects			
Keystone XL[3]	Liquids Pipelines	US 8.0	US 0.3
Keystone Hardisty Terminal[1,3]	Liquids Pipelines	0.3	0.1
BC west coast LNG-related projects			
Coastal GasLink	Canadian Natural Gas Pipelines	4.8	0.4
NGTL System – Merrick	Canadian Natural Gas Pipelines	1.9	—
		21.9	**0.9**
Foreign exchange impact on medium to longer-term projects[4]		**2.0**	**0.1**
Total medium to longer-term projects (billions of Cdn$)		**23.9**	**1.0**

1 Regulatory approvals have been obtained; additional commercial support is being pursued.
2 Our proportionate share.
3 Carrying value reflects amount remaining after impairment charge recorded in 2015.
4 Reflects U.S./Canada foreign exchange rate of 1.25 at December 31, 2017.

2017 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 similar to 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 72 and 100 for reconciliations to the GAAP equivalents.

year ended December 31 (millions of $, except per share amounts)	2017	2016	2015
Income			
Revenues	**13,449**	12,547	11,353
Net income/(loss) attributable to common shares	**2,997**	124	(1,240)
per common share – basic	**$3.44**	$0.16	($1.75)
– diluted	**$3.43**	$0.16	($1.75)
Comparable EBITDA	**7,377**	6,647	5,908
Comparable earnings	**2,690**	2,108	1,755
per common share	**$3.09**	$2.78	$2.48
Cash flows			
Net cash provided by operations	**5,230**	5,069	4,384
Comparable funds generated from operations	**5,641**	5,171	4,815
Comparable distributable cash flow			
– reflecting all maintenance capital expenditures	**3,599**	3,541	3,457
– reflecting only non-recoverable maintenance capital expenditures	**4,963**	4,482	4,243
Comparable distributable cash flow per common share			
– reflecting all maintenance capital expenditures	**$4.13**	$4.67	$4.88
– reflecting only non-recoverable maintenance capital expenditures	**$5.69**	$5.91	$5.98
Capital spending[1]	**9,210**	6,067	4,922
Acquisitions, net of cash acquired	**—**	13,608	236
Proceeds from sales of assets, net of transaction costs	**5,317**	6	—
Balance sheet			
Total assets	**86,101**	88,051	64,398
Long-term debt	**34,741**	40,150	31,456
Junior subordinated notes	**7,007**	3,931	2,409
Preferred shares	**3,980**	3,980	2,499
Non-controlling interests	**1,852**	1,726	1,717
Common shareholders' equity	**21,059**	20,277	13,939
Dividends declared[2]			
per common share	**$2.50**	$2.26	$2.08
Basic common shares (millions)			
– weighted average	**872**	759	709
– issued and outstanding	**881**	864	703

1 Includes capital expenditures, capital projects in development and contributions to equity investments.

2 See financial condition on page 78 for details on preferred share dividends.

Consolidated results

year ended December 31 (millions of $, except per share amounts)	2017	2016	2015
Segmented earnings/(losses)			
Canadian Natural Gas Pipelines	**1,236**	1,307	1,367
U.S. Natural Gas Pipelines	**1,760**	1,190	597
Mexico Natural Gas Pipelines	**426**	287	169
Liquids Pipelines	**(251)**	806	(2,661)
Energy	**1,552**	(1,157)	781
Corporate	**(39)**	(120)	(152)
Total segmented earnings	**4,684**	2,313	101
Interest expense	**(2,069)**	(1,998)	(1,370)
Allowance for funds used during construction	**507**	419	295
Interest income and other	**184**	103	(132)
Income/(loss) before income taxes	**3,306**	837	(1,106)
Income tax recovery/(expense)	**89**	(352)	(34)
Net income/(loss)	**3,395**	485	(1,140)
Net income attributable to non-controlling interests	**(238)**	(252)	(6)
Net income/(loss) attributable to controlling interests	**3,157**	233	(1,146)
Preferred share dividends	**(160)**	(109)	(94)
Net income/(loss) attributable to common shares	**2,997**	124	(1,240)
Net income/(loss) per common share			
–basic	**$3.44**	$0.16	($1.75)
–diluted	**$3.43**	$0.16	($1.75)

Net income attributable to common shares in 2017 was $2,997 million or $3.44 per share (2016 – $124 million or $0.16 per share; 2015 – loss of $1,240 million or $1.75 per share). Net income per common share increased by $3.28 per share in 2017 compared to 2016 due to the changes in net income described below, as well as the dilutive effect of issuing 161 million common shares in 2016 and common shares issued under our DRP and corporate ATM program in 2017.

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

2017

- an $804 million recovery of deferred income taxes as a result of U.S. Tax Reform
- a $307 million after-tax net gain related to the monetization of our U.S. Northeast power business, which included a $440 million after-tax gain on the sale of TC Hydro, an incremental after-tax loss of $190 million recorded on the sale of the thermal and wind package, $23 million of after-tax third-party insurance proceeds related to a 2017 Ravenswood outage, $14 million of after-tax disposition costs, and income tax adjustments
- a $136 million after-tax gain related to the sale of our Ontario solar 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 $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 which were expensed pending further advancement of the project
- a $7 million income tax recovery related to the realized loss on a third party sale of Keystone XL project assets. A provision for the expected pre-tax loss on these assets was included in our 2015 impairment charge, but the related income tax recoveries could not be recorded until realized.

2016

- a $656 million after-tax impairment of Ravenswood goodwill. 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
- an $873 million after-tax loss on U.S. Northeast power assets held for sale which included an $863 million after-tax loss on the thermal and wind package held for sale and $10 million of after-tax disposition costs
- a $176 million after-tax impairment charge on the carrying value of our Alberta PPAs (both directly and through our equity investment in ASTC Power Partnership) as a result of our decision to terminate the PPAs and a $68 million after-tax loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the PPA terminations
- costs associated with the acquisition of Columbia resulting in an after-tax charge of $273 million which included $109 million of dividend equivalent payments on the subscription receipts issued as part of the permanent financing of the transaction, $90 million of retention, severance and integration costs, $36 million of acquisition costs and a $44 million deferred income tax adjustment upon closing of the acquisition, partially offset by $6 million of interest earned on the subscription receipt funds held in escrow prior to their conversion to common shares
- $28 million of income tax recoveries related to the realized loss on a third party sale of Keystone XL project assets. A provision for the expected pre-tax loss on these assets was included in our fourth quarter 2015 impairment charge, but the related income tax recoveries could not be recorded until realized
- an after-tax charge of $42 million related to Keystone XL costs for the maintenance and liquidation of project assets which were expensed pending further advancement of the project
- an after-tax charge of $16 million for restructuring mainly related to expected future losses under lease commitments. These charges formed part of a restructuring initiative, which commenced in 2015, to maximize the effectiveness and efficiency of our existing operations and reduce overall costs
- an additional $3 million after-tax loss on the sale of TC Offshore which closed in early 2016.

2015

- a $2,891 million after-tax impairment charge on the carrying value of our investment in Keystone XL and related projects
- an $86 million after-tax loss provision related to the sale of TC Offshore which closed in early 2016
- a net charge of $74 million after tax for restructuring comprised of $42 million mainly related to 2015 severance costs and a provision of $32 million for 2016 planned severance costs and expected future losses under lease commitments. These charges formed part of a restructuring initiative, which commenced in 2015, to maximize the effectiveness and efficiency of our existing operations and reduce overall costs
- a $43 million after-tax charge relating to an impairment in value of turbine equipment held for future use in our Energy business
- a $34 million adjustment to income tax expense due to the enactment of a two per cent increase in the Alberta corporate income tax rate in June 2015
- a charge of $27 million after tax related to Bruce Power's retirement of debt in conjunction with the merger of the Bruce A and Bruce B partnerships
- a $199 million positive income adjustment related to the impact on our net income from non-controlling interests of TC PipeLines, LP's impairment of their equity investment in Great Lakes.

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/(loss) attributable to common shares to comparable earnings is shown in the following table.

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

Reconciliation of net income/(loss) to comparable earnings

year ended December 31 (millions of $, except per share amounts)	2017	2016	2015
Net income/(loss) attributable to common shares	**2,997**	124	(1,240)
Specific items (net of tax):			
U.S. Tax Reform adjustment	**(804)**	—	—
Net (gain)/loss on sales of U.S. Northeast power assets	**(307)**	873	—
Gain on sale of Ontario solar assets	**(136)**	—	—
Energy East impairment charge	**954**	—	—
Integration and acquisition related costs – Columbia	**69**	273	—
Keystone XL asset costs	**28**	42	—
Keystone XL income tax recoveries	**(7)**	(28)	—
Ravenswood goodwill impairment	**—**	656	—
Alberta PPA terminations and settlement	**—**	244	—
Restructuring costs	**—**	16	74
TC Offshore loss on sale	**—**	3	86
Keystone XL impairment charge	**—**	—	2,891
Turbine equipment impairment charge	**—**	—	43
Alberta corporate income tax rate increase	**—**	—	34
Bruce Power merger – debt retirement charge	**—**	—	27
Non-controlling interests (TC PipeLines, LP – Great Lakes impairment)	**—**	—	(199)
Risk management activities[1]	**(104)**	(95)	39
Comparable earnings	**2,690**	2,108	1,755
Net income/(loss) per common share	**$3.44**	$0.16	($1.75)
Specific items (net of tax):			
U.S. Tax Reform adjustment	**(0.92)**	—	—
Net (gain)/loss on sales of U.S. Northeast power assets	**(0.34)**	1.15	—
Gain on sale of Ontario solar assets	**(0.16)**	—	—
Energy East impairment charge	**1.09**	—	—
Integration and acquisition related costs – Columbia	**0.08**	0.37	—
Keystone XL asset costs	**0.03**	0.06	—
Keystone XL income tax recoveries	**(0.01)**	(0.04)	—
Ravenswood goodwill impairment	**—**	0.86	—
Alberta PPA terminations and settlement	**—**	0.32	—
Restructuring costs	**—**	0.02	0.10
TC Offshore loss on sale	**—**	—	0.12
Keystone XL impairment charge	**—**	—	4.08
Turbine equipment impairment charge	**—**	—	0.06
Alberta corporate income tax rate increase	**—**	—	0.05
Bruce Power merger – debt retirement charge	**—**	—	0.04
Non-controlling interests (TC PipeLines, LP – Great Lakes impairment)	**—**	—	(0.28)
Risk management activities	**(0.12)**	(0.12)	0.06
Comparable earnings per common share	**$3.09**	$2.78	$2.48

year ended December 31 (millions of $)	2017	2016	2015
Canadian Power	**11**	4	(8)
U.S. Power	**39**	113	(30)
Liquids marketing	**—**	(2)	—
Natural Gas Storage	**12**	8	1
Interest rate	**(1)**	—	—
Foreign exchange	**88**	26	(21)
Income taxes attributable to risk management activities	**(45)**	(54)	19
Total unrealized gains/(losses) from risk management activities	**104**	95	(39)

Comparable earnings

Comparable earnings per share in 2017 and 2016 were impacted by the dilutive effect of issuing 161 million common shares in 2016 and common shares issued under our DRP and corporate ATM program in 2017. See the Financial condition section of this MD&A for further information on common share issuances.

Comparable earnings in 2017 were $582 million higher than 2016, resulting in an increase of $0.31 per common share. The 2017 increase in comparable earnings was primarily the net result of:

- 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
- 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
- higher AFUDC on our rate-regulated U.S. natural gas pipelines, as well as 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 recovery of certain Coastal GasLink project costs and the termination of the PRGT project
- lower contribution from U.S. Power due to the monetization of our U.S. Northeast power generation assets in second quarter 2017 and the continued wind-down of our U.S. power marketing operations
- 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 note issuances in 2017, net of maturities.

Comparable earnings in 2016 were $353 million higher than 2015, resulting in an increase of $0.30 per common share. The 2016 increase in comparable earnings was primarily the net result of:

- higher contribution from U.S. Natural Gas Pipelines primarily due to incremental earnings following the July 1, 2016 Columbia acquisition, higher ANR transportation revenues resulting from a FERC-approved rate settlement effective August 1, 2016, new contracts on ANR Southeast Mainline and lower OM&A expenses
- higher interest expense from debt issuances and lower capitalized interest
- higher interest income and other due to realized gains in 2016 compared to realized losses in 2015 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar denominated income
- lower earnings from Liquids Pipelines due to the net effect of higher contracted and lower uncontracted volumes on Keystone, as well as lower volumes on Marketlink
- higher AFUDC on our rate-regulated projects including those for the NGTL System, Energy East, Columbia and Mexico pipelines
- higher contribution from Mexico Natural Gas Pipelines primarily due to earnings from Topolobampo beginning in July 2016
- higher earnings from Natural Gas Storage due to higher realized natural gas storage price spreads.

Cash flows

Net cash provided by operations of $5.2 billion and comparable funds generated from operations of $5.6 billion were three per cent and nine per cent higher, respectively, in 2017 compared to 2016, 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 the impact of all maintenance capital expenditures, was $3.6 billion in 2017 compared to $3.5 billion in 2016, primarily due to higher comparable funds generated from operations partially offset by higher maintenance capital. Comparable distributable cash flow, reflecting only non-recoverable maintenance capital, was $5.0 billion in 2017 compared to $4.5 billion in 2016 due primarily to higher comparable funds generated from operations. Comparable distributable cash flow per common share was also impacted by common share issuances in 2016 and 2017. See 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 $)	2017	2016	2015
Canadian Natural Gas Pipelines	**2,181**	1,525	1,596
U.S. Natural Gas Pipelines	**3,830**	1,522	537
Mexico Natural Gas Pipelines	**1,954**	1,142	566
Liquids Pipelines	**529**	1,137	1,601
Energy	**675**	708	558
Corporate	**41**	33	64
	9,210	6,067	4,922

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

We invested $9.2 billion in capital projects in 2017 to optimize the value of our existing assets and 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.

Proceeds from sales of assets

In 2017, we completed the sales of TC Hydro, Ravenswood, Ironwood, Kibby Wind and Ocean State Power for net proceeds of approximately 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 $21.7 billion since 2015. At December 31, 2017, common shareholders' equity represented 33 per cent (31 per cent in 2016) of our capital structure, while other subordinated capital, in the form of junior subordinated notes and preferred shares, represented an additional 16 per cent (12 per cent in 2016). See Financial condition for more information about our capital structure.

Dividends

We increased the quarterly dividend on our outstanding common shares by 10.4 per cent to $0.69 per common share for the quarter ending March 31, 2018 which equates to an annual dividend of $2.76 per common share. This is the 18th 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 at the upper end of eight to ten per cent through 2020 and an additional eight to ten per cent in 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 $)	2017	2016	2015
Common shares	**1,339**	1,436	1,446
Preferred shares	**155**	100	92

OUTLOOK

Earnings

Our 2018 earnings, after excluding specific items, are expected to be higher than 2017 primarily due to the impact of the following:

- contributions from new Columbia Gas and Columbia Gulf projects coming into service
- full year of earnings from Grand Rapids and Northern Courier placed in service in the latter half of 2017
- completion of the Napanee power plant in Ontario
- growth in the average investment base for the NGTL System
- benefit of lower U.S. income tax rates. See U.S. Tax Reform section for further information.

Partially offset by:

- lower Energy earnings due to the monetization of the U.S. Northeast power generation assets in second quarter 2017, the sale of the Ontario solar assets in late-2017 and the continued wind-down of our U.S. power marketing operations
- lower Bruce Power equity income due to a higher number of planned outage days
- discontinuation of AFUDC on Energy East and related projects
- decrease in Canadian Mainline average investment base.

See relevant business segment outlook for additional details.

Consolidated capital spending and equity investments

We expect to spend approximately $9 billion in 2018 on growth projects, maintenance capital and contributions to equity investments. The majority of the anticipated 2018 capital program will be focused on U.S., Canadian and Mexico natural gas pipeline growth projects and maintenance, with additional capital spend attributable to completing construction on Napanee and contributions to the Bruce Power life extension program and maintenance.

NATURAL GAS PIPELINES BUSINESS

Our natural gas pipeline network transports natural gas from supply basins to local distribution companies, power generation and individual facilities, interconnecting pipelines and other businesses across Canada, the U.S. and Mexico. Our network of pipelines taps into virtually every major supply basin and transports over 25 per cent of continental daily natural gas needs through:

- wholly-owned natural gas pipelines – 80,800 km (50,100 miles)
- partially-owned natural gas pipelines – 11,100 km (7,000 miles).

In addition to our interstate 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 services 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, LDC, LNG export, interconnect and electric power generation markets
- connections to growing Canadian and U.S. shale gas and other supplies
- additional new pipeline developments within Mexico
- greenfield development projects, such as infrastructure for LNG exports from the west coast of Canada and the Gulf of Mexico

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

Highlights

- In 2017, we placed into service approximately $3.3 billion of new facilities including $1.7 billion on the NGTL System, $0.2 billion on the Canadian Mainline and $1.4 billion related to U.S. Natural Gas Pipelines
- In 2017, we originated an additional US$0.3 billion of capital projects related to U.S. Natural Gas Pipelines
- In June 2017, we announced a new $2 billion expansion program on our NGTL System based on new contracted customer demand for approximately 3 Bcf/d of incremental firm receipt and delivery services
- In July 2017, we were notified that Pacific Northwest (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 Prince Rupert Gas Transmission (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.
- In November 2017, we began delivering volumes under the new Dawn Long-Term Fixed-Price (LTFP) service on the Canadian Mainline
- In December 2017, we filed, subject to NEB approval, a Supplemental Agreement for the Canadian Mainline to address 2018 to 2020 tolls, to meet a condition of the NEB approval for the 2015 - 2030 Tolls and Tariff Application
- In January 2018, the Columbia Gas Leach XPress project was placed in service
- In February 2018, we announced an additional $2.4 billion expansion program on our NGTL System.

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

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. It is these two supply areas, along with growing demand for firm transportation in the oil sands area and to our major export points at Empress and Alberta/B.C. delivery locations, that is driving our large capital program for new pipeline facilities. The NGTL System is also well positioned to connect WCSB supply to potential LNG export facilities on the Canadian west coast.

Canadian Mainline: This is a major pipeline that was originally designed as a long haul delivery system transporting supply from the WCSB across Canada to Ontario and Québec to deliver gas to downstream Canadian and U.S. markets. The Canadian Mainline continues this role and is also growing to accommodate additional supply connections closer to its markets.

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 assets are very well positioned to connect growing supply and market 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 Pipeline System: ANR is our pipeline system that 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 is our pipeline system 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 is now transitioning to a north-to-south flow and expanding to accommodate new supply in the Appalachian Basin and its interconnects with Columbia Gas and other pipelines to deliver gas to various Gulf Coast markets.

Mexico Pipeline Network: We also have a growing network of natural gas pipelines coupled with a large portfolio of projects under construction in Mexico, including Tula and Villa de Reyes and the 60 per cent-owned Sur de Texas pipeline project through our joint venture with IEnova.

Regulation of tolls and cost recovery

Our natural gas pipelines are generally regulated by the NEB in Canada, by the 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 the 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 us 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 105 Bcf/d by 2020, reflecting an increase of approximately 10 Bcf/d from 2017 levels.

This expected increased demand for natural gas, coupled with the annual decline rate of 15 per cent to 20 per cent for natural gas production, implies up to 25 Bcf/d of new production per year will be required, 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
- the production of Alberta oil sands, despite new greenfield oil sands projects that have not yet begun construction or have been delayed in the recent low oil price environment
- exports to Mexico to fuel power generation facilities.

Natural gas producers continue to progress opportunities to sell natural gas to global markets which involves connecting natural gas supplies to proposed LNG export terminals along the U.S. Gulf Coast and the west coast of 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 exploration 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.

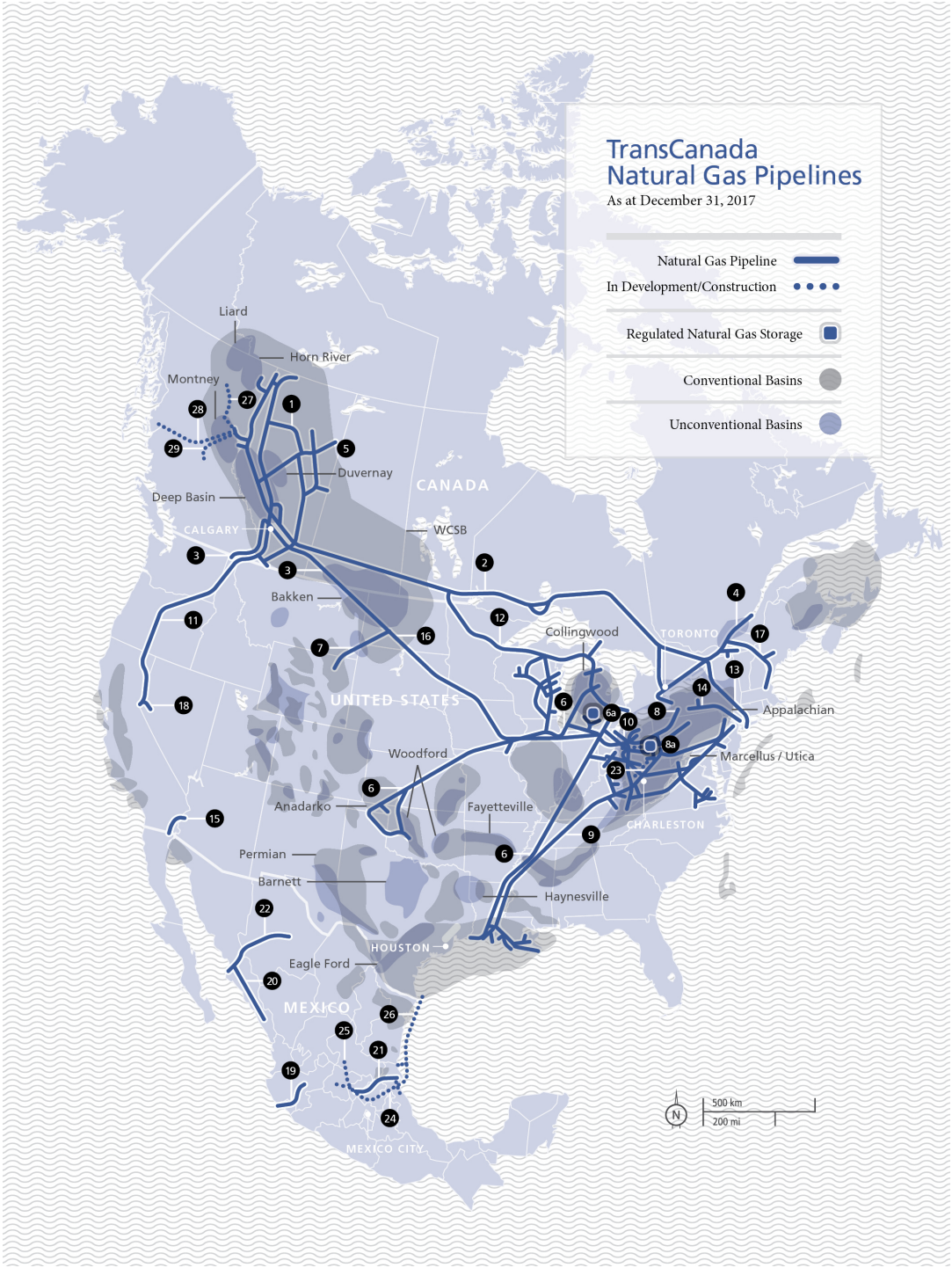
More competition

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

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 2018, one of our key focus areas will be the continued execution of our existing capital program that includes further expansion of the NGTL System as well as concluding several projects on the Columbia Gas and Gulf systems 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, 2017
Natural Gas Pipeline
In Development/Construction
Regulated Natural Gas Storage
Conventional Basins
Unconventional Basins
Liard
Horn River
Montney
Duvernay
Deep Basin
CALGARY
WCSB
CANADA
Bakken
Collingwood
TORONTO
UNITED STATES
Appalachian
Marcellus / Utica
Woodford
Anadarko
Fayetteville
CHARLESTON
Permian
Barnett
Haynesville
HOUSTON
Eagle Ford
MEXICO
MEXICO CITY
500 km
200 mi
N

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	24,320 km (15,112 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	14,077 km (8,747 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)	572 km (355 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 that serves the northeast U.S.	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 mile) pipeline supplying natural gas to a petrochemical complex at Joffre, Alberta.	100%
*	Great Lakes Canada	58 km (36 miles)	Transports natural gas from the Great Lakes system in the U.S. to Ontario, near Dawn, through a connection at the U.S. border underneath the St. Clair River.	100%
	U.S. pipelines			
6	ANR	15,109 km (9,388 miles)	Transports natural gas from various supply basins to markets throughout the 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 25.7 per cent of the system through our interest in TC PipeLines, LP.	25.7%
8	Columbia Gas	18,113 km (11,255 miles)	Transports natural gas from supply primarily in the Appalachian Basin to markets 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	5,377 km (3,341 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 25.7 per cent of the system through our interest in TC PipeLines, LP.	25.7%
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 65.5 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 25.7 per cent interest in TC PipeLines, LP.	65.5%
13	Iroquois	669 km (416 miles)	Connects with the Canadian Mainline and serves markets in New York. We effectively own 13.4 per cent of the system through a 0.7 per cent direct ownership and our 25.7 per cent interest in TC PipeLines, LP.	13.4%

		Length	Description	Effective ownership
14	Millennium	407 km (253 miles)	Natural gas pipeline supplied by local production, storage fields and interconnecting upstream pipelines to serve markets along its route and to the U.S. Northeast.	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 25.7 per cent of the system through our interest in TC PipeLines, LP.	25.7%
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 12.9 per cent of the system through our 25.7 per cent interest in TC PipeLines, LP.	12.9%
17	Portland (PNGTS)	475 km (295 miles)	Connects with TQM near East Hereford, Québec to deliver natural gas to customers in the U.S. Northeast. We effectively own 15.9 per cent of the system through our 25.7 per cent interest in TC PipeLines, LP.	15.9%
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 25.7 per cent of the system through our interest in TC PipeLines, LP.	25.7%
	Mexican pipelines			
19	Guadalajara	315 km (196 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, Sinaloa in Mexico. Connects to the Topolobampo Pipeline at El Oro.	100%
21	Tamazunchale	375 km (233 miles)	Transports natural gas from Naranjos, Veracruz in east central Mexico to Tamazunchale, San Luis Potosi and on to El Sauz, Querétaro.	100%
22	Topolobampo	560 km (348 miles)	Transports natural gas to Topolobampo, Sinaloa, from interconnects with third-party pipelines in El Oro, Sinaloa and El Encino, Chihuahua in Mexico.	100%
	Under construction			
	Canadian pipelines			
*	NGTL 2018 Facilities	68 km** (42 miles)	An expansion program on the NGTL System including pipeline and compression additions with expected in-service dates by November 2018.	100%
	U.S. pipelines			
23	Mountaineer XPress	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%
*	Leach XPress[1]	260 km** (160 miles)	A Columbia Gas project designed to transport supply from the Marcellus and Utica shale plays to points along the system and to an interconnect with Columbia Gulf.	100%
*	Cameron Access	55 km** (34 miles)	A Columbia Gulf project to deliver natural gas from points along the Columbia Gulf system to the Cameron LNG facility.	100%
*	WB XPress	47 km** (29 miles)	A Columbia Gas project designed to transport Marcellus supply both eastbound (to interconnects and mid-Atlantic markets) and westbound (to interconnect pipelines).	100%
*	Gulf XPress	N/A	A Columbia Gulf project associated with the Mountaineer XPress expansion and consisting of the addition of seven greenfield mid-point compressor stations along Columbia Gulf.	100%

	Under construction (continued)	Length	Description	Effective ownership
	Mexican pipelines			
24	Tula	300 km** (186 miles)	The pipeline will originate in Tuxpan in the state of Veracruz and extend through the states of Puebla and Hidalgo, supplying natural gas to CFE combined-cycle power generating facilities in each of those jurisdictions as well as to the central and western regions of Mexico.	100%
25	Villa de Reyes	420 km** (261 miles)	The pipeline will deliver natural gas from Tula, Hildago to Villa de Reyes, San Luis Potosi, connecting to the Tamazunchale and Tula pipelines.	100%
26	Sur de Texas	800 km** (497 miles)	The pipeline will begin offshore in the Gulf of Mexico at the border point near Brownsville, Texas and end in Tuxpan, in the state of Veracruz, connecting with the Tamazunchale and Tula pipelines.	60%
	Permitting and pre-construction phase			
	Canadian pipelines			
27	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	138 km** (86 miles)	An expansion program on the NGTL System including multiple pipeline projects and compression additions with expected in-service dates by November 2019.	100%
*	NGTL 2020 Facilities	125 km** (78 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	401 km** (249 miles)	An expansion program on the NGTL System including multiple pipeline projects and compression additions with expected in-service dates by November 2021.	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%
*	Portland XPress	N/A	A PNGTS project to expand the system through the construction of compression and related facilities at existing compressor stations.	15.9%
	In development			
	Canadian pipelines			
28	Coastal GasLink	670 km** (416 miles)	To deliver natural gas from the Montney gas producing region at an expected interconnect with the NGTL System near Dawson Creek, B.C. to LNG Canada's proposed facility near Kitimat, B.C.	100%
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%

1 Leach XPress was placed in service in January 2018.

* 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 business is subject to regulation by various federal and provincial governmental agencies. The NEB, however, has comprehensive jurisdiction over our Canadian natural gas business. The NEB approves tolls and services that are in the public interest and provides 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 concluded its two-year settlement arrangement in 2017 and is currently working with interested parties for a new arrangement for 2018 and longer. The Mainline system is entering the fourth 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 service, 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

NGTL System

In February 2018, we announced a new NGTL System expansion totaling $2.4 billion, with in-service dates between 2019 and 2021. The new expansion program includes approximately 375 km (233 miles) of 16- to 48-inch pipeline, four compression units totaling 120 MW and associated meter stations and facilities. We anticipate incremental firm receipt contracts of 664 TJ/d (620 MMcf/d) and firm delivery contracts to our major border export and intra-basin delivery locations of 1.1 PJ/d (1.0 Bcf/d).

In June 2017, we announced a new $2 billion expansion program on our NGTL System based on new contracted customer demand for approximately 3.2 PJ/d (3.0 Bcf/d) of incremental firm receipt and delivery services.

With the 2021 expansion program, NGTL now has a $7.2 billion capital program, excluding the $1.9 billion Merrick pipeline project.

In 2017, we placed approximately $1.7 billion of facilities in service and reduced remaining project estimates by $0.6 billion.

Towerbirch Expansion

In March 2017, the Government of Canada approved the $0.4 billion Towerbirch Project. This project consists of a 55 km (34 mile), 36-inch pipeline loop and a 32 km (20 mile), 30-inch pipeline extension of the NGTL System in northwest Alberta and northeast B.C. The NEB approval included the continued use of the existing rolled-in tolling methodology for this project. The project was placed in service in November 2017.

North Montney

In March 2017, we filed an application with the NEB for a variance to the existing approvals for the North Montney Project on the NGTL System to remove the condition that the project could only proceed once a positive FID was made for the PNW LNG project. The North Montney project is now underpinned by restructured 20-year commercial contracts with shippers and is not dependent on the LNG project proceeding. A hearing on the matter began the week of January 22, 2018 and a decision from the NEB is anticipated in second quarter 2018.

Sundre Crossover Project
On December 28, 2017, the NEB approved the Sundre Crossover Project on the NGTL System. The approximate $100 million, 21 km (13 mile), 42-inch pipeline project will increase delivery of 245 TJ/d (229 MMcf/d) to the Alberta / B.C. border to connect with TransCanada downstream pipelines. In-service is planned for April 1, 2018.

NGTL 2018 Revenue Requirement
NGTL's 2016-2017 Settlement, which established revenue requirements for the system, expired on December 31, 2017. We continue to work with interested parties towards a new revenue requirement arrangement for 2018 and longer. While these discussions are underway, NGTL is operating under interim tolls for 2018 that were approved by the NEB on November 24, 2017.

Canadian Mainline
The Canadian Mainline currently has a near-term capital program of approximately $0.2 billion for completion to 2021. In 2017, we placed approximately $0.2 billion of facilities in service, consisting primarily of the Vaughan Loop in November.

Dawn Long-Term Fixed-Price Service
On November 1, 2017, we began offering the new Dawn LTFP service on the Canadian Mainline. This NEB-approved 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 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.

Canadian Mainline 2018-2020 Toll Review
Tolls for the Canadian Mainline were previously established for 2015 to 2017 in accordance with the terms of the 2015-2030 LDC Settlement. While the settlement specified tolls for 2015 to 2020, the NEB ordered a toll review halfway through the six-year period, to be filed by December 31, 2017. The 2018-2020 toll review must include costs, forecast volumes, contract levels, deferral balances and any other material changes. A Supplemental Agreement for the 2018 to 2020 period was executed between TransCanada and the Eastern LDCs on December 8, 2017 and filed for approval with the NEB on December 18, 2017. The Agreement, supported by a majority of Canadian Mainline stakeholders, proposes lower tolls, preserves an incentive arrangement that provides the opportunity for a 10.1 per cent or greater return on a 40 percent deemed equity and describes the revenue requirements and billing determinants for the 2018-2020 period.

We anticipate the NEB will provide direction and process to adjudicate the application in first quarter 2018. Interim tolls for 2018, as established by the Supplemental Agreement, were filed and subsequently approved by the NEB on December 19, 2017.

Maple Compressor Expansion Project
In 2017, the Canadian Mainline received requests for expansion capacity to the southern Ontario market plus delivery to Atlantic Canada via the TQM and PNGTS systems. The requests for approximately 86 TJ/d (80 MMcf/d) of firm service underpin the need for new compression at the existing Maple compressor site. Customers have executed 15-year precedent agreements to proceed with the project which has an estimated cost of $110 million. An application to the NEB seeking project approval was filed November 2, 2017. We have requested a decision by the NEB to proceed with the project in the first quarter of 2018 to meet an anticipated in-service date of November 1, 2019.

Eastern Mainline Project
The $2 billion Eastern Mainline project that was conditioned on the approval and construction of the Energy East pipeline will not be proceeding. See the Liquids Pipelines Significant events section for further discussion on Energy East.

LNG Pipeline Projects

Prince Rupert Gas Transmission (PRGT)
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 pipeline. In accordance with the terms of the agreement, all project costs incurred to advance PRGT, including carrying charges, were fully recoverable upon termination and, as a result, we received a payment of $0.6 billion from Progress in October 2017.

Coastal GasLink

The continuing delay in the FID for the LNG Canada project triggered a restructuring of 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 September 2017, an approximate $80 million payment was received related to costs incurred since inception of the project. Following a payment of $8 million in fourth quarter 2017, additional quarterly payments of approximately $7 million will be received until further notice. We continue to work with LNG Canada under the agreement towards an FID. Coastal GasLink filed an amendment to the Environmental Assessment Certificate in November 2017 for an alternate route on a portion of the pipeline. A decision from the B.C. Environmental Assessment Office is expected in 2018.

Coastal GasLink is a 670 km (416 mile) pipeline that will deliver natural gas from the Dawson Creek, B.C. area to LNG Canada's proposed gas liquefaction facility near Kitimat, B.C. Should the project not proceed, our project costs, including carrying charges, are fully recoverable.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 and 2015 results have been adjusted to reflect this change.

year ended December 31 (millions of $)	2017	2016	2015
NGTL System	**996**	968	900
Canadian Mainline	**1,043**	1,105	1,193
Other Canadian pipelines[1]	**110**	116	131
Business development	**(5)**	(7)	(8)
Comparable EBITDA	**2,144**	2,182	2,216
Depreciation and amortization	**(908)**	(875)	(849)
Comparable EBIT and segmented earnings	**1,236**	1,307	1,367

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

Canadian Natural Gas Pipelines comparable EBIT and segmented earnings decreased by $71 million in 2017 compared to 2016 and by $60 million in 2016 compared to 2015.

Net income and comparable EBITDA for our rate-regulated Canadian 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.

year ended December 31 (millions of $)	2017	2016	2015
Net income			
NGTL System	**352**	318	269
Canadian Mainline	**199**	208	213
Average investment base			
NGTL System	**8,385**	7,451	6,698
Canadian Mainline	**4,184**	4,441	4,784

Net income for the NGTL System was $34 million higher in 2017 compared to 2016 mainly due to a higher average investment base, partially offset by higher carrying charges on regulatory deferrals. Net income in 2016 was $49 million higher than 2015 due to a higher average investment base and increased OM&A incentive earnings recorded in 2016. The two-year 2016-2017 Revenue Requirement Settlement included an ROE of 10.1 per cent on 40 per cent deemed equity and a mechanism for sharing variances above and below a fixed annual OM&A amount with flow-through treatment of all other costs. The 2015 NGTL Settlement included a 10.1 per cent ROE on deemed common equity of 40 per cent and a mechanism for sharing variances between actual and a fixed OM&A cost amount.

Canadian Mainline's net income in 2017 decreased by $9 million compared to 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. Net income in 2016 was $5 million lower than 2015 mainly due to a lower average investment base and higher carrying charges to shippers on the 2016 net revenue surplus, partially offset by higher incentive earnings in 2016. The lower average investment base in 2017 and 2016 was mainly due to depreciation and the inclusion of the 2016 and 2015 net revenue surpluses in the investment base.

The Canadian Mainline operated under the NEB 2014 Decision throughout 2015 to 2017. 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 a six-year fixed toll term from 2015 to 2020.

Depreciation and amortization

Depreciation and amortization was $33 million higher in 2017 compared to 2016, and $26 million higher in 2016 compared to 2015, primarily due to new 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 or other toll proposals approved by the NEB.

Canadian Natural Gas Pipelines earnings in 2018 are expected to be modestly lower than 2017 due to a declining Canadian Mainline investment base and lower incentive earnings, partially offset by continued growth in the NGTL System. We expect the NGTL System investment base to continue to grow as we extend and expand the northwest supply facilities, northeast delivery facilities and incremental service at our major border delivery locations in response to requests for both receipt and delivery firm service on the system.

In accordance with the terms of the 2015-2030 LDC Settlement, the Canadian Mainline is subject to a toll review for 2018 to 2020. A Supplemental Agreement for the 2018 to 2020 period was executed and filed for approval with the NEB in December 2017. Interim tolls were filed and subsequently approved by the NEB in December 2017.

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 $2.2 billion in 2017 for our Canadian Natural Gas Pipelines and expect to spend approximately $1.7 billion in 2018 primarily on the NGTL System expansion projects, Canadian Mainline capacity projects and maintenance capital which are all immediately reflected in investment base.

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. The FERC, however, has comprehensive jurisdiction over our U.S. natural gas business. The 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.

The 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 the FERC for a new determination of rates, subject to any moratorium in effect. Similarly, the 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 the 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 300 km (186 miles) of pipeline ranging in size from 16 to 36 inches. Midstream also manages our small mineral rights positions in the Marcellus and Utica shale areas.

TransCanada's Master Limited Partnership

We own, through subsidiaries, a 25.7 per cent effective ownership in TC PipeLines, LP,a MLP which trades on the New York Stock Exchange under the symbol TCP. TC PipeLines, LP has ownership interests in the GTN, Northern Border, Bison, Great Lakes, North Baja, Tuscarora, Iroquois, and PNGTS 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 28.

SIGNIFICANT EVENTS

Leach XPress

Leach XPress was placed in service January 1, 2018. This Columbia Gas project transports approximately 1.6 PJ/d (1.5 Bcf/d) of Marcellus and Utica gas supply to delivery points along the system.

Rayne XPress

Rayne Xpress was placed in service November 2, 2017. This Columbia Gulf project transports approximately 1.1 PJ/d (1.0 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.

Modernization I & II

Columbia Gas and its customers have 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 to control systems. The US$1.5 billion Modernization I arrangement was completed under the terms of the 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 in 2020. As per terms of the arrangements, facilities in service by October 31 collect revenues effective February 1 of the following year.

Buckeye XPress

The Buckeye XPress project (BXP) 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 290 TJ/d (275 MMcf/d) of incremental pipeline capacity to accommodate growing Appalachian production. We expect BXP to be placed in service in late-2020.

Mountaineer XPress Project
The Mountaineer XPress project (MXP), a Columbia Gas project designed to transport approximately 2.9 PJ/d (2.7 Bcf/d) of Marcellus and Utica gas supply to delivery points along the pipeline and to the Leach interconnect with Columbia Gulf, is expected to be placed in service in fourth quarter 2018. The current estimated project cost of US$2.6 billion reflects an increase in construction cost estimates of US$0.6 billion.As a result of a cost sharing mechanism, overall project returns are not anticipated to be materially affected.

Gibraltar
Gibraltar, a Midstream project to construct a 1,000 TJ/d (934 MMcf/d) dry gas header pipeline in southwest Pennsylvania, was placed in service November 1, 2017.

Portland XPress
PNGTS has 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 PNGTS system to bring its certificated capacity from 222 TJ/d (210 MMcf/d) to 290 TJ/d (275 MMcf/d). The approximately US$80 million Portland XPress Project (PXP) will proceed concurrently with upstream capacity expansions. The in-service dates of PXP are being phased-in over a three-year period beginning November 1, 2018.

FERC Update
The FERC regained a quorum of three commissioners in August 2017 and two additional commissioners were approved by the U.S. Senate on November 2, 2017. The FERC has stated that it intends to expeditiously address the resulting backlog of pending applications. The FERC certificate for WB XPress was received in November 2017 and the FERC certificates for MXP and Gulf XPress projects were received on December 29, 2017.

Great Lakes
Rate Case
On October 30, 2017, Great Lakes filed a rate settlement with the FERC to satisfy its obligations from its 2013 rate settlement for new rates to be in effect by January 1, 2018. The 2017 Great Lakes Settlement, if approved by the FERC, will decrease Great Lakes' maximum transportation rates by 27 per cent beginning October 1, 2017. Great Lakes expects that the impact from other changes, including the recent long-term transportation contract with the Canadian Mainline as described below, other revenue opportunities on the system and the elimination of the revenue sharing mechanism with its customers, will essentially offset the full year impact of the reduction in Great Lakes' rates beginning in 2018.

Impact of Dawn LTFP
In conjunction with the Canadian Mainline's LTFP service, Great Lakes entered into a new ten-year gas transportation contract with the Canadian Mainline. This contract received NEB approval in September 2017, effective November 1, 2017, and contains volume reduction options up to full contract quantity beginning in year three.

Northern Border Settlement
Northern Border filed a rate settlement with the FERC on December 4, 2017, reflecting a settlement-in-principle with its shippers, which precludes the need to file a general rate case as contemplated by its previous 2012 settlement. Northern Border anticipates that the FERC will accept the settlement agreement and that it will be unopposed. This is expected to provide Northern Border with rate stability over the longer term. We have a 12.9 per cent indirect ownership interest in Northern Border through TC PipeLines, LP.

Sale of Iroquois and PNGTS to TC PipeLines, LP
In June 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 PNGTS to TC PipeLines, LP. Proceeds from these transactions were US$765 million, before post-closing adjustments. Proceeds were comprised of US$597 million in cash and US$168 million representing a proportionate share of Iroquois and PNGTS debt.

Columbia Pipeline Partners LP
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 payment of US$0.10 per common unit for an aggregate transaction value of US$921 million.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 and 2015 results have been adjusted to reflect this change.

year ended December 31 (millions of US$, unless otherwise noted)	2017	2016	2015
Columbia Gas[1]	**623**	269	—
ANR	**400**	321	220
TC PipeLines, LP[2,3]	**110**	118	106
Midstream[1]	**93**	40	—
Columbia Gulf[1]	**76**	25	—
Great Lakes[3,4]	**64**	60	63
Other U.S. pipelines[1,2,3,5]	**108**	74	87
Non-controlling interests[6]	**341**	365	292
Business development	**(2)**	(3)	(12)
Comparable EBITDA	**1,813**	1,269	756
Depreciation and amortization	**(453)**	(322)	(194)
Comparable EBIT	**1,360**	947	562
Foreign exchange impact	**410**	310	160
Comparable EBIT (Cdn$)	**1,770**	1,257	722
Specific items:			
Integration and acquisition related costs - Columbia	**(10)**	(63)	—
TC Offshore loss on sale	**—**	(4)	(125)
Segmented earnings (Cdn$)	**1,760**	1,190	597

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

2 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 PNGTS to TC PipeLines, LP and the remaining 11.81 per cent to TC PipeLines, LP on June 1, 2017. On April 1, 2015, we sold our remaining 30 per cent direct interest in GTN to TC PipeLines, LP.

3 TC PipeLines, LP periodically conducts at-the-market equity issuances which decrease our ownership in TC PipeLines, LP. The following shows our ownership interest in TC PipeLines, LP and our effective ownership interest of Great Lakes and PNGTS through our ownership interest in TC PipeLines, LP at the dates presented.

	Effective ownership percentage as of		
	December 31, 2017	December 31, 2016	December 31, 2015
TC PipeLines, LP	25.7	26.8	28.0
Effective ownership through TC PipeLines, LP:			
Great Lakes	11.9	12.5	13.0
PNGTS	15.9	13.4	—

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 Includes our direct ownership in Iroquois and PNGTS (until June 1, 2017) and GTN (until April 1, 2015), our effective ownership in Millennium and Hardy Storage, and general and administrative costs related to U.S. natural gas assets.

6 Comparable EBITDA for the portions of TC PipeLines, LP, PNGTS (until June 1, 2017), and CPPL we do not own. Effective February 17, 2017, we acquired the remaining publicly held units of CPPL.

U.S. Natural Gas Pipelines segmented earnings in 2017 increased by $570 million compared to 2016 and increased by $593 million in 2016 compared to 2015. Segmented earnings in 2017 included pre-tax costs of $10 million (2016 - $63 million) mainly related to retention and severance expenses resulting from the Columbia acquisition. Segmented earnings in 2016 and 2015 also included pre-tax losses of $4 million and $125 million, respectively, 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$544 million higher in 2017 than 2016 primarily due to the net effect of:

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

Comparable EBITDA for U.S. Natural Gas Pipelines was US$513 million higher in 2016 than 2015 primarily due to the net effect of:

- incremental earnings from Columbia as a result of the acquisition on July 1, 2016
- higher ANR transportation revenue resulting from a FERC-approved rate settlement, effective August 1, 2016, higher Southeast Mainline transportation revenues and lower pipeline integrity work on ANR, partially offset by lower incidental commodity sales and a one time settlement in 2015 with an owner of adjacent facilities for commercial interruption of ANR's service
- higher contributions from TC PipeLines, LP mainly due to higher GTN transportation revenues.

Depreciation and amortization

Depreciation and amortization was US$131 million higher in 2017 compared to 2016, and US$128 million higher in 2016 compared to 2015, 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 include the impact of 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 2018 than in 2017 due to, among other factors, increased revenues following the completion of expansion projects on the Columbia Gas and Columbia Gulf systems. These projects 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 constrained natural gas production in the Marcellus and Utica producing regions to areas of demand.

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. We expect ANR to provide stable earnings for 2018 compared to 2017.

Great Lakes, Northern Border and GTN have benefited from market conditions through 2017 that have maintained the value of their services. Further, both Great Lakes and Northern Border have filed rate settlements with the FERC on October 30, 2017 and December 4, 2017, respectively. These settlements are expected to provide rate certainty and predictable earnings through 2018 and beyond.

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.

Capital spending

We spent a total of US$3.2 billion in 2017 on our U.S. Natural Gas Pipelines and expect to spend approximately US$4.1 billion in 2018 primarily on Columbia Gas and Columbia Gulf expansion projects as well as ANR and Columbia Gas maintenance capital, the majority of which we expect to recover in future tolls.

Mexico Natural Gas Pipelines

UNDERSTANDING OUR MEXICO NATURAL GAS PIPELINES SEGMENT

For over a decade, Mexico has been undergoing a significant transition from 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 electric utility. The pipeline operator is at risk for the construction and ongoing operating costs and is subject to penalties, excluding force majeure claims, if the project is not ready for in-service by a specific date.

Our Mexican pipelines have approved tariffs, services and related rates for other potential users of the pipeline. Most of the contracts that currently underpin the construction and operation of the facilities in Mexico are long-term, fixed-rate contracts designed to recover the cost of our service.

SIGNIFICANT EVENTS

Topolobampo

The Topolobampo project is substantially complete, excluding a 20 km (12 mile) section due to delays experienced by the Secretary of Energy, the governmental department which conducts indigenous consultations in Mexico. The issue has been resolved and construction on this final section is expected to be completed in the second quarter of 2018.

The overall project is a 560 km (348 mile), 30-inch pipeline with a cost of US$1.2 billion, an increase of US$0.2 billion from the original estimate due to the delays from the force majeure event. The project will receive natural gas from upstream pipelines near El Encino, in the state of Chihuahua, and deliver natural gas from these interconnecting pipelines to delivery points along the pipeline route including our Mazatlán pipeline at El Oro, in the state of Sinaloa. Construction of the pipeline is supported by a 25-year natural gas TSA for 717 TJ/d (670 MMcf/d) with the CFE. Under the terms of the TSA, the delay in the 20 km (12 mile) section was recognized as a force majeure event with provisions allowing for the collection of revenue from the original TSA service commencement date of July 2016.

Mazatlán

The Mazatlán project was commissioned and brought into full service in July 2017. The project is a 430 km (267 mile), 24-inch pipeline running from El Oro to Mazatlán within the state of Sinaloa with a cost of US$0.4 billion. The pipeline is supported by a 25-year natural gas TSA for 214 TJ/d (200 MMcf/d) with the CFE and is awaiting continuous natural gas supply from upstream, third-party interconnecting pipelines, however, our contractual obligations have been met and therefore, the collection and recognition of revenue began under the terms of the TSA in December 2016.

Tula

The Tula project is a US$0.7 billion, 36-inch, 300 km (186 mile) pipeline with a 16-inch, 24 km (15 mile) 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, Querétaro extending through the states of Puebla and Hidalgo. Project completion has been revised to late 2019 due to delays experienced by the Secretary of Energy, the governmental department which conducts indigenous consultations in Mexico. Construction of the Tula pipeline was substantially completed in 2017 with the exception of approximately 90 km (56 miles) of the pipeline. The delay has been recognized by the CFE as a force majeure event and we are finalizing amending agreements to formalize the schedule and payment impacts. As a result of the delay and increased cost of land and permitting, estimated project costs have increased by US$0.1 billion from the original estimate.

Villa de Reyes

The Villa de Reyes project is a US$0.8 billion project with 36- and 24-inch pipelines totaling 420 km (261 miles), 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 between Tula, in the state of Hidalgo, and Villa de Reyes, in the state of San Luis Potosí. The project will interconnect with our Tamazunchale and Tula pipelines as well as with other transporters in the region. Construction of the project has commenced, however, delays due to archeological investigations by federal authorities have caused the in-service date of the project to be revised to late 2018. The delay has been recognized as a force majeure event by the CFE and we are finalizing amending agreements to formalize the schedule and payment impacts. As a result of the delay and increased cost of land and permitting, estimated project costs have increased by US$0.2 billion from the original estimate.

Sur de Texas

The US$2.1 billion 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. Pipeline construction on the 42-inch diameter, approximately 800 km (497 mile) pipeline is progressing toward an anticipated in-service date of late 2018, with approximately 60 per cent of the off-shore construction completed as of the end of 2017. The pipeline will start offshore in the Gulf of Mexico, at the border point near Brownsville, Texas, and end in Tuxpan, in the state of Veracruz. The project will deliver natural gas to our Tamazunchale and Tula pipelines and to other transporters in the region.

TransGas

In 2017, we recognized an impairment charge of $12 million on our 46.5 per cent equity investment in TransGas de Occidente S.A. (TransGas). TransGas constructed and operated a natural gas pipeline in Colombia over a 20-year build-own-transfer 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 impairment charge represents the write-down of the remaining carrying value of our equity investment.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 and 2015 results have been adjusted to reflect this change.

year ended December 31 (millions of US$, unless otherwise noted)	2017	2016	2015
Tamazunchale	**112**	105	108
Topolobampo	**157**	81	(3)
Guadalajara	**68**	67	69
Mazatlán	**65**	5	(2)
Sur de Texas[1]	**8**	—	—
Other	**(11)**	(3)	4
Business development	**—**	(5)	(12)
Comparable EBITDA	**399**	250	164
Depreciation and amortization	**(72)**	(35)	(34)
Comparable EBIT	**327**	215	130
Foreign exchange impact	**99**	72	39
Comparable EBIT and segmented earnings (Cdn$)	**426**	287	169

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 2017increased by $139 million compared to 2016 and increased by $118 million in 2016 compared to 2015.

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. The inter-affiliate loan interest is fully offset in interest income and other in the Corporate segment.
- the impairment of our equity investment in TransGas.

Comparable EBITDA for Mexico Natural Gas Pipelines was US$86 million higher in 2016 than 2015 primarily due the net effect of:

- incremental earnings from Topolobampo. The Topolobampo project experienced a delay in construction which, under the terms of our TSA with the CFE, constitutes a force majeure event with provisions allowing for the collection and recognition of revenue as per the original TSA service commencement date of July 2016
- incremental earnings from Mazatlán. Construction is complete and the collection and recognition of revenue began per the terms of the TSA in December 2016
- lower business development costs expensed in 2016 due to the capitalization of costs for work on projects successfully awarded and under construction.

Depreciation and amortization

Depreciation and amortization increased by US$37 million in 2017 compared to 2016 primarily due to the commencement of depreciation on Topolobampo and Mazatlán. Depreciation and amortization remained consistent in 2016 compared to 2015.

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 project.

We expect 2018 earnings from the Topolobampo, Tamazunchale, Guadalajara and Mazatlán pipelines to remain consistent with 2017 due to the long-term nature of the underlying revenue contracts. Sur de Texas and Villa de Reyes are expected to be in service in late 2018.

Capital spending

We spent a total of US$1.5 billion in 2017 for our Mexican natural gas pipeline capital projects and expect to spend approximately US$0.7 billion in 2018, primarily on construction of Sur de Texas, Villa de Reyes and Tula.

NATURAL GAS PIPELINES – BUSINESS RISKS

The following are risks specific to our natural gas pipelines business. See page 83 for information about general risks that affect the company as a whole, including other operational risks, HSE risks 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 downstream pipes largely depend on Appalachian supply. We continue to monitor any changes in our customers' natural gas production plans and how these changes 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 competing demand 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. Furthermore, as a regulated pipeline business, we can apply for approval with the regulator to set tolls consistent with the level of throughput expected on our pipelines.

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 gas pipeline infrastructure. As well, sustained low gas prices could impact our shippers' financial condition and their ability to meet their transportation service cost obligations.

Regulatory risk

Decisions by regulators 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 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 unfavorable due to the 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 the meters regularly to ensure accuracy, and continuously maintain compression equipment to ensure safe and reliable operation.

Liquids Pipelines

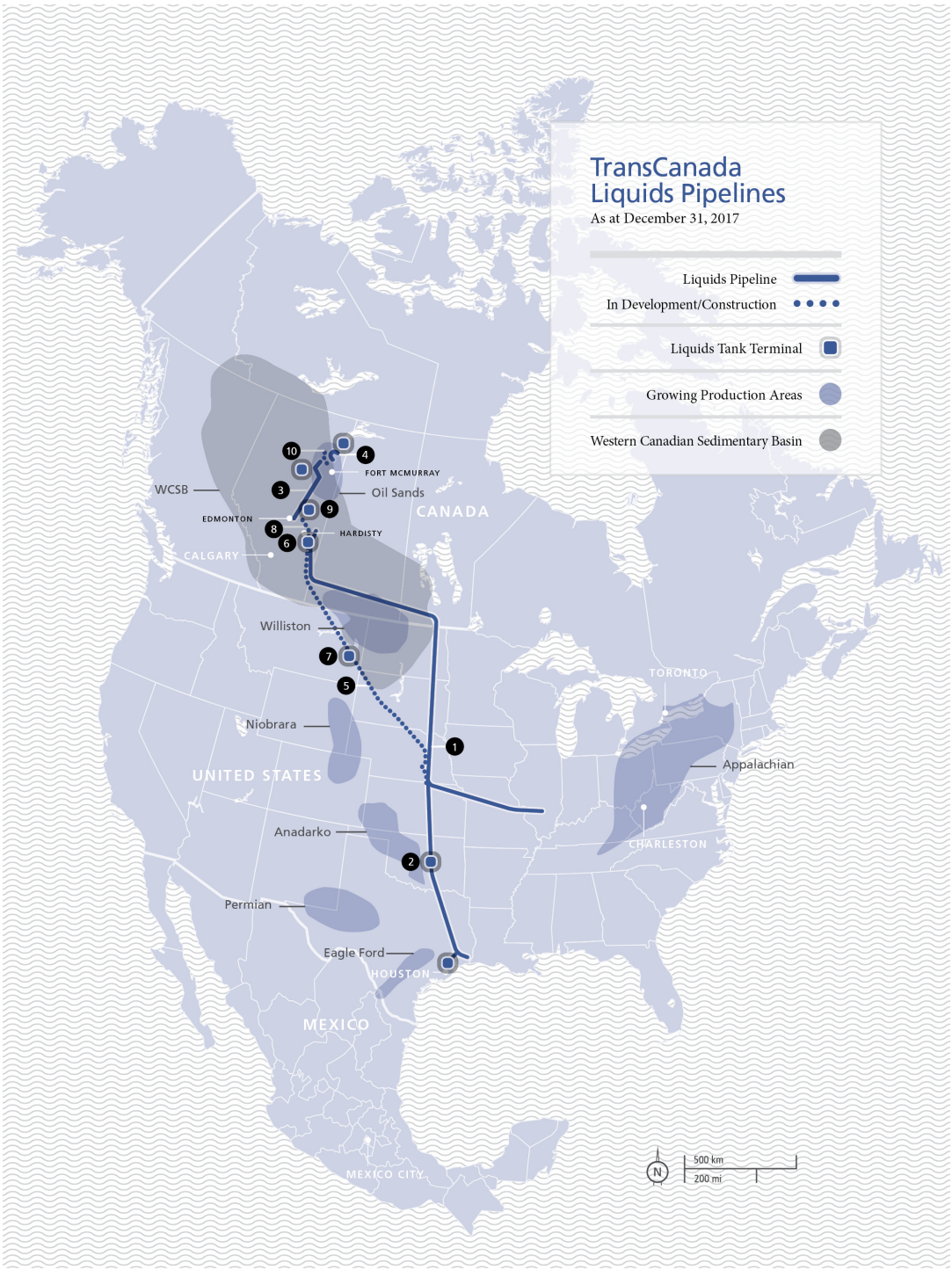
Our existing liquids pipelines infrastructure connects Alberta crude oil supplies to U.S. refining markets in Illinois, Oklahoma, Texas and the U.S. Gulf Coast. Our proposed future pipeline infrastructure would expand capacity for Canadian and U.S. crude oil to access key markets. We will also pursue enhancing our transportation service offerings to other areas of the liquids pipelines business value chain.

Strategy at a glance

- Focus on accessing and delivering growing North American liquids supply to key markets by expanding our liquids pipelines infrastructure to deliver directly from supply regions seamlessly along a contiguous path to market
- Focus on maximizing the value from our current operating assets, securing organic growth around these assets, identifying potential acquisition opportunities and positioning our business development activities to capture growth opportunities
- Expand transportation service offerings to other areas of the liquids pipelines business value chain including condensate transportation and ancillary services, such as short and long term storage of liquids, which complement our pipeline transportation infrastructure
- Continued development and construction of our proposed infrastructure projects to provide North America with a crucial liquids transportation network to transport growing supply directly to key markets and provide opportunities for us to further expand our liquids pipelines business.

Highlights

- Received the U.S. Presidential Permit for the Keystone XL project
- Received approval for a Nebraska pipeline route and secured sufficient commercial support to commence construction preparation for the Keystone XL project
- Secured incremental long-term contractual support following the conclusion of Keystone pipeline and Marketlink open seasons
- Informed the NEB that we will not be proceeding with the Energy East and Eastern Mainline project applications
- Completed construction of Grand Rapids and Northern Courier, two new intra-Alberta liquids pipelines


TransCanada
Liquids Pipelines
As at December 31, 2017
Liquids Pipeline
In Development/Construction
Liquids Tank Terminal
Growing Production Areas
Western Canadian Sedimentary Basin
FORT MCMURRAY
WCSB
Oil Sands
CANADA
EDMONTON
HARDISTY
CALGARY
Williston
TORONTO
Niobrara
Appalachian
UNITED STATES
Anadarko
CHARLESTON
Permian
Eagle Ford
HOUSTON
MEXICO
MEXICO CITY
N
500 km
200 mi

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		Terminal and pipeline facilities to transport crude oil from the market hub at Cushing, Oklahoma to the U.S. Gulf Coast refining markets 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%
	In development			
5	Keystone XL	1,906 km (1,184 miles)	To transport crude oil from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System.	100%
6	Keystone Hardisty Terminal		Crude oil terminal located at Hardisty, Alberta, providing western Canadian producers with crude oil batch accumulation tankage and access to the Keystone Pipeline System.	100%
7	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%
8 9	Heartland Pipeline and TC Terminals	200 km (125 miles)	Terminal and pipeline facilities to transport crude oil from the Edmonton/Heartland, Alberta region to facilities in Hardisty, Alberta.	100%
10	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%

UNDERSTANDING OUR LIQUIDS PIPELINES BUSINESS

Our liquids pipelines business primarily consists of pipelines, which efficiently move crude oil from major supply sources to markets where crude oil can be refined into various petroleum products, and ancillary services such as short and long term storage of liquids at terminals to optimize the value of our assets and expand into other areas of the liquids business value chain.

The Keystone Pipeline System, our largest liquids pipelines asset, moves 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. The Grand Rapids and Northern Courier pipelines, two new intra-Alberta liquids pipelines, are recent additions to our portfolio. Both greenfield pipelines provide transportation solutions for producers in northern and western Athabasca regions.

We provide pipeline capacity to shippers 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. Uncontracted capacity is periodically offered to the market to secure additional contracts or offered to the market on a spot basis which provides opportunities to generate incremental earnings. Storage of liquids 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 terms of service and fixed monthly payments are determined by transportation service arrangements negotiated with shippers. These long-term arrangements provide for the recovery of costs we incur to construct and operate the system.

Our liquids marketing business provides customers with a variety of crude oil marketing services including transportation, storage, and crude oil supply, primarily transacted through the purchase and sale of physical crude oil. In order to provide these services, TransCanada Liquids Marketing (TCLM) holds contractual rights on TransCanada and third-party owned pipelines and tank terminals. TCLM currently captures value in the market based on locational and time differentials.

Business environment

Crude oil continues to drive the modern economy, with people's need for efficient and reliable transportation and products developed from petroleum generating the majority of global crude oil demand. Despite the emergence of new technologies that have made vehicles more fuel efficient, the International Energy Agency projects annual global crude oil demand growth will increase from 94 million Bbl/d in 2016 to 105 million Bbl/d in 2040 driven primarily by growth in Asia and developing countries.

The impact of recent OPEC crude oil production cuts has stabilized global prices, following the severe downturn that began in 2014. Global crude oil inventories are decreasing and are expected to continue to decline. A key driver to near and medium term crude oil pricing going forward will be the production decisions made by OPEC and some non-OPEC producers. Crude oil supply and demand is expected to balance in the near to medium term, as these producing countries extend their current production cuts through 2018. As the market comes into balance, crude oil prices are expected to recover to a range which will support further investment and supply growth.

Our liquids pipelines business is well positioned to endure the impact of short-term commodity price fluctuations and supply adjustments. 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, irrespective of commodity prices or throughput. The cyclical supply and demand nature of commodities and their price movements can have a secondary impact on our business where our shippers may choose to accelerate or delay certain new projects. 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.

Supply and demand outlook

Canada

Canada has the world's third largest crude oil reserves and has the potential to increase its position as a major world supplier as crude oil production from mature oil fields around the world declines. Alberta produces the majority of the crude oil in the WCSB, which is the primary source of crude oil supply for the Keystone Pipeline System. In its 2017 Crude Oil Forecast, Markets and Transportation report, the Canadian Association of Petroleum Producers (CAPP) estimates 2018 WCSB crude oil supply will reach 0.8 million Bbl/d of conventional crude oil and condensate and 3.7 million Bbl/d of oil sands crude oil for a total of approximately 4.5 million Bbl/d, an increase of 0.3 million Bbl/d from 2017 levels. The report also forecasts WCSB crude oil supply will increase to 5.0 million Bbl/d by 2025 and to 5.5 million Bbl/d by 2030.

According to the 2017 Alberta's Energy Reserves and Supply/Demand Outlook, the AER estimates there was approximately 165 billion barrels of economically and technically recoverable conventional and oil sands reserves in Alberta in 2016. Oil sands projects have a long reserve life with steady production after initial ramp up. In its 2014 Responsible Canadian Energy report, CAPP estimates a typical oil sands mine has a 25 to 50-year lifespan, while an in-situ operation will run ten to 15 years on average. This longevity aligns with the producer's desire to secure long term market access for their reserves. The Keystone Pipeline System, Grand Rapids and Northern Courier are all underpinned by long term contracts.

U.S.

The U.S. is among the world's largest crude oil producers, with average production estimated at over 9.3 million Bbl/d in 2017 as a result of significant growth in light tight oil (LTO) production over the last five years. The U.S. EIA forecasts 1.4 million Bbl/d of U.S. production growth from 2017 to 2029, peaking at 10.5 million Bbl/d by 2029. It also forecasts U.S. production to average 10.3 million Bbl/d in 2018, which would mark the highest annual average production in U.S. history, surpassing the previous record of 9.6 million Bbl/d set in 1970.

Most continental U.S. crude oil is produced from the Williston, Eagle Ford, Niobrara, Permian, Anadarko and Appalachian production areas which represent some of the sources of crude oil supply for our Marketlink system at Cushing, Oklahoma. The Marketlink system, with connectivity to the Houston and Port Arthur, Texas and Lake Charles, Louisiana refining markets, is well positioned to transport this growing supply.

The U.S. is the world's largest crude oil consumer. U.S. crude oil demand is forecasted to grow slightly from approximately 16 million Bbl/d to over 17 million Bbl/d by 2040. U.S. Gulf Coast refineries are mainly configured to process heavy and medium crude oil and cannot easily switch to processing LTO in large quantities without significant capital investments. U.S. Gulf Coast refineries currently require approximately 8.6 million Bbl/d of crude oil, of which approximately 3.2 million Bbl/d is heavy and medium supplied primarily by offshore imports. This level of heavy demand is not expected to change significantly in the near or longer term. Our assets are well positioned to deliver Canadian crude oil to this significant market.

Strategic priorities

We remain committed to advancing our portfolio of commercially secured projects to connect growing Canadian and U.S. crude oil supply to key markets, maximizing the value from our existing assets, leveraging existing infrastructure and seeking new opportunities across the liquids pipelines value chain.

In 2017, we made significant progress on our Keystone XL project, which included receiving the U.S. Presidential Permit, approval of a route through Nebraska and securing sufficient commercial support. We have commenced construction preparation and primary construction execution is expected to begin in 2019. Completing the Keystone XL project will be a significant focus in order to augment and expand the Keystone Pipeline System's access in the U.S. Gulf Coast and connect to over 4.3 million Bbl/d of regional refinery capacity in Houston and Port Arthur, Texas and Lake Charles, Louisiana. Expanding the pipeline's market reach is expected to enhance both short and long haul volumes.

Within Alberta, we leveraged our extensive natural gas pipeline footprint and experience to develop an intra-Alberta liquids pipelines business. Resilient growth in oil sands production continues to support the need for intra-Alberta pipelines, such as our recently commissioned, 50 per cent owned, Grand Rapids pipeline that moves crude oil from northwest of Fort McMurray, Alberta to the market hub at Edmonton, Alberta, making it the first major pipeline completed in the west Athabasca region. Our joint venture between Grand Rapids and Keyera Corp. enhances our ability to access a reliable and cost effective source of diluent. The White Spruce pipeline will transport crude oil from Canadian Natural Resources Limited's Horizon facility into Grand Rapids and will further expand our regional footprint. In addition, our recently commissioned Northern Courier pipeline will facilitate supply from the Fort Hills Energy Partners' mine to market. With additional commercial support, the Heartland pipeline, TC Terminals and Keystone Hardisty Terminal projects, which have received regulatory approval, will allow shippers to seamlessly connect with the Keystone Pipeline System and other pipelines that transport crude oil outside of Alberta, and ultimately provide our customers with a contiguous path from production to market.

We will 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 as the business environment recovers.

SIGNIFICANT EVENTS

Keystone Pipeline System

In the fourth quarter of 2017, we concluded open seasons for Keystone pipeline and Marketlink and secured incremental long-term contractual support.

On November 16, 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 National Response Center and the Pipeline and Hazardous Materials Safety Administration (PHMSA). On November 29, 2017, the pipeline was repaired and returned to service at a reduced pressure in the affected section of the pipeline. Further investigative activities and corrective measures required by PHMSA are planned for 2018.

This shutdown did not have a significant impact on our 2017 earnings.

Keystone XL

In February 2017, we filed an application with the Nebraska Public Service Commission (PSC) seeking approval for the Keystone XL pipeline route through that state and received approval for an alternate route on November 20, 2017. On November 24, 2017, we filed a motion with the Nebraska 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. On December 19, 2017, the Nebraska PSC denied this motion. On December 27, 2017, opponents of the Keystone XL project, and intervenors in the Keystone XL Nebraska regulatory proceeding, filed an appeal of the November 20, 2017 PSC decision seeking to have that decision overturned. TransCanada supports the decision of the Nebraska PSC and will actively participate in the appeal process to defend that decision.

In March 2017, the U.S. Department of State issued a U.S. Presidential Permit authorizing construction of the U.S./Canada border crossing facilities of the Keystone XL project. We discontinued our claim under Chapter 11 of the North American Free Trade Agreement and withdrew the U.S. Constitutional challenge. Later 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 law suits which were denied on November 22, 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 the Keystone XL project from Hardisty, Alberta to Cushing, Oklahoma and the U.S. Gulf Coast. The successful open season concluded on October 26, 2017.

In January 2018, we secured sufficient commercial support to commence construction preparation for the Keystone XL project. We expect to commence primary construction in 2019 and construction will take approximately two years to complete.

Energy East

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 carrying value of the projects, including AFUDC capitalized since inception, and recorded a pre-tax, non-cash charge of $1,256 million ($954 million after-tax) in fourth quarter 2017. 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

In late August 2017, the Grand Rapids pipeline, jointly owned by TransCanada and PetroChina Canada Ltd., was placed in service. The 460 km (287 mile) crude oil transportation system connects producing areas northwest of Fort McMurray, Alberta to terminals in the Edmonton/Heartland region.

Northern Courier

In November 2017, the Northern Courier pipeline, a 90 km (56 mile) pipeline system which transports bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta, achieved commercial in-service.

White Spruce

In first quarter 2018, we anticipate receiving a decision from the AER on the regulatory permit to construct 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. Due to the delay in the regulatory process, we expect the White Spruce pipeline to be in-service in 2019.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 and 2015 results have been adjusted to reflect this change.

year ended December 31 (millions of $)	2017	2016	2015
Keystone Pipeline System	**1,283**	1,155	1,332
Intra-Alberta pipelines	**33**	—	—
Other services[1]	**32**	(3)	(24)
Comparable EBITDA	**1,348**	1,152	1,308
Depreciation and amortization	**(309)**	(292)	(283)
Comparable EBIT	**1,039**	860	1,025
Specific items:			
Energy East impairment charge	**(1,256)**	—	—
Keystone XL asset costs	**(34)**	(52)	—
Keystone XL impairment charge	**—**	—	(3,686)
Risk management activities	**—**	(2)	—
Segmented (losses)/earnings	**(251)**	806	(2,661)
Comparable EBIT denominated as follows:			
Canadian dollars	**255**	223	227
U.S. dollars	**604**	482	623
Foreign exchange impact	**180**	155	175
Comparable EBIT	**1,039**	860	1,025

1 Includes primarily liquids marketing and business development activities.

Liquids Pipelines segmented earnings were $1,057 million lower in 2017 compared to 2016 and $3,467 million higher in 2016 than 2015.

Segmented losses in 2017 included a $1,256 million pre-tax impairment charge for the Energy East pipeline and $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 in 2016 also included unrealized losses from changes in the fair value of derivatives related to our liquids marketing business. Segmented losses in 2015 included a $3,686 million pre-tax impairment charge related to Keystone XL and related projects. See Critical accounting estimates on page 91 for more information. These amounts have been excluded from our calculation of comparable EBIT. The remainder of the Liquids Pipelines segmented earnings are equivalent to comparable EBIT, which, along with comparable EBITDA, are discussed below.

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 the liquids marketing business
- new 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
- a weaker U.S. dollar which had a negative impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

Comparable EBITDA for Liquids Pipelines was $156 million lower in 2016 than in 2015 primarily due to the net effect of:

- lower uncontracted volumes on Keystone pipeline
- lower volumes on Marketlink
- higher contracted volumes on Keystone pipeline
- a higher contribution from the liquids marketing business
- lower business development activities
- a stronger U.S. dollar which had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

Depreciation and amortization

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. Depreciation and amortization was $9 million higher in 2016 than in 2015 mainly due to the effect of a stronger U.S. dollar.

OUTLOOK

Earnings

Our 2018 earnings, excluding specific items, are expected to be higher than 2017, primarily as a result of full year earnings from the Northern Courier and Grand Rapids pipelines and incremental long-term contracts on the Keystone Pipeline System.

Capital spending

We spent a total of $0.5 billion in 2017 for our Liquids Pipelines capital projects and expect to spend approximately $0.4 billion in 2018.

BUSINESS RISKS

The following are risks specific to our liquids pipelines business. See page 83 for information about general risks that affect TransCanada as a whole, including other operational risks, HSE risks, and financial risks.

Operational

Optimizing and maintaining availability of our liquids pipelines is essential to the success of our Liquids Pipelines 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 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 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 the 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. 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 develop a competitive position in the North American liquids transportation market to connect growing crude oil and condensate 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 condensate 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 supply, primarily transacted through the purchase and sale of physical crude oil. Volatility in commodity prices and changing market conditions could adversely impact the value of those 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 Other information – Risks and risk management.

Energy

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

The power business includes approximately 7,000 MW of generation capacity that we 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, nuclear, and wind. The majority of these assets are supported by long-term contracts.

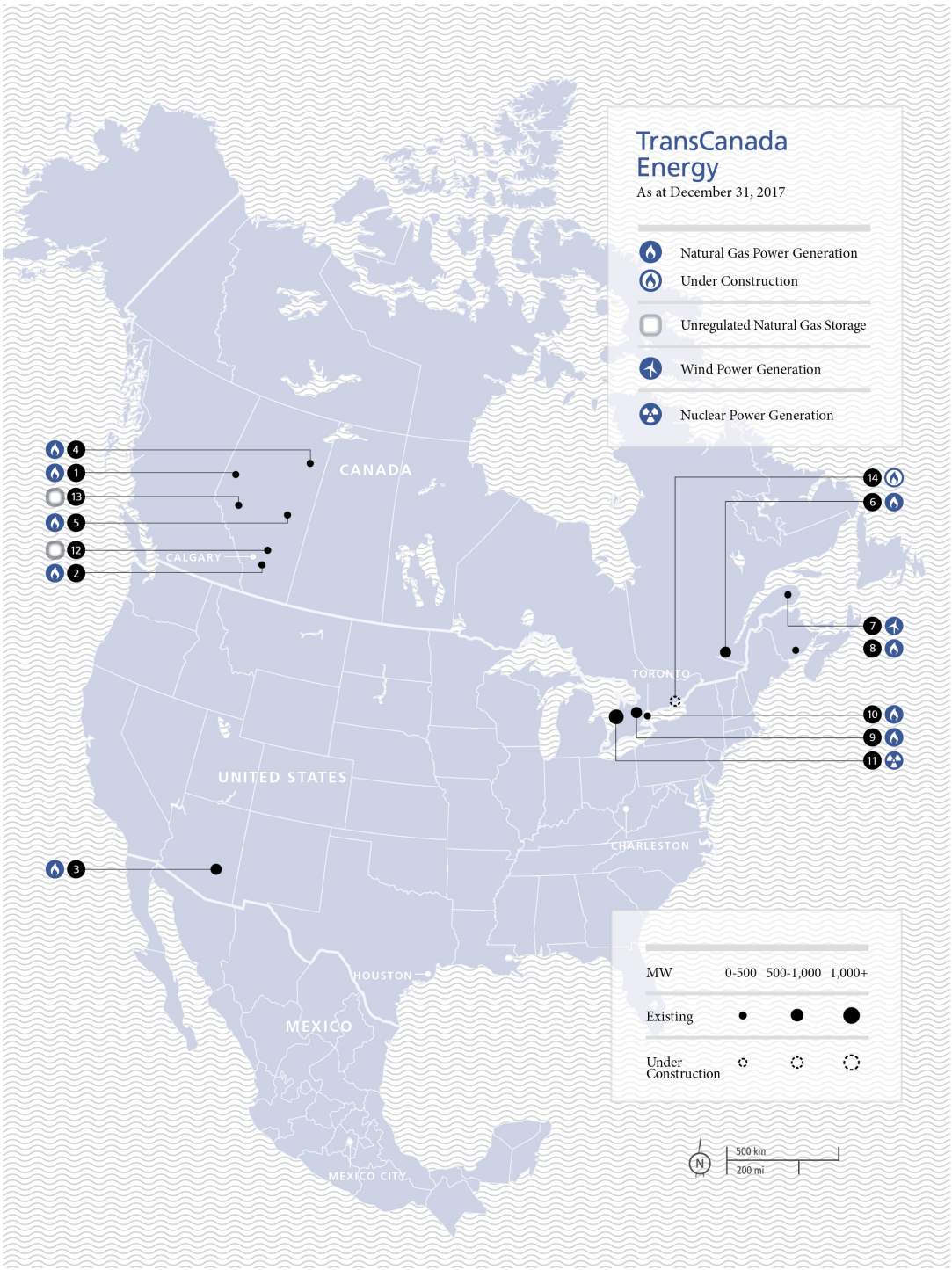
We own and operate approximately 118 Bcf of unregulated natural gas storage capacity in Alberta and hold a contract with a third party for additional storage, in total accounting for approximately one-third of all storage capacity in the province.

Strategy at a glance

- Maximize the value of our diverse portfolio of Energy assets through safe and reliable operations
- Execute capital programs on time and on budget
- Pursue North American growth in contracted power infrastructure as electric systems move to become less carbon intensive and absorb growing amounts of intermittent renewable capacity
- Maximize the value of our existing unregulated Alberta natural gas storage assets in an expanding gas marketplace that requires storage to balance and provide gas system reliability.

Highlights

- Strong financial results from Bruce Power; work is progressing on the life extension program
- Completed monetization of the U.S. Northeast generation assets and entered into an agreement to sell U.S. power retail contracts as part of the continued wind down of our U.S. power marketing operations
- Divestiture of Ontario solar assets to capture robust market value and provide capital to support near-term growth
- Construction continues on the 900 MW Napanee natural gas-fired power plant with expected in service in fourth quarter 2018.


TransCanada Energy
As at December 31, 2017
Natural Gas Power Generation
Under Construction
Unregulated Natural Gas Storage
Wind Power Generation
Nuclear Power Generation
CANADA
CALGARY
TORONTO
UNITED STATES
CHARLESTON
HOUSTON
MEXICO
MEXICO CITY
MW 0-500 500-1,000 1,000+
Existing
Under Construction
N
500 km
200 mi

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

		Generating capacity (MW)	Type of fuel	Description	Ownership
Canadian Power 6,983 MW of power generation capacity (including facilities under construction)					
Western Power 1,021 MW of power generation capacity in Alberta and Arizona					
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	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%
4	Mackay River	205	natural gas	Cogeneration plant in Fort McMurray, Alberta.	100%
5	Redwater	46	natural gas	Cogeneration plant in Redwater, Alberta.	100%
Eastern Power 2,863 MW of power generation capacity (including facilities under construction)					
6	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%
7	Cartier Wind	365[1]	wind	Five wind power facilities in Gaspésie, Québec. Power sold under 20-year PPAs with Hydro-Québec which expire between 2026 and 2032.	62%
8	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%
9	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%
10	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 3,099 MW of power generation capacity					
11	Bruce Power	3,099[1]	nuclear	Eight operating reactors in Tiverton, Ontario. Bruce Power leases the eight nuclear facilities from OPG.	48.4%
Unregulated natural gas storage 118 Bcf of non-regulated natural gas storage capacity					
12	Crossfield	68 Bcf		Underground facility connected to the NGTL System in Crossfield, Alberta.	100%
13	Edson	50 Bcf		Underground facility connected to the NGTL System near Edson, Alberta.	100%
Under construction					
14	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 fourth quarter 2018.	100%

1 Our share of power generation capacity.

UNDERSTANDING OUR ENERGY BUSINESS

Our Energy business is made up of two groups:

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

Our U.S. Northeast Power generation assets were sold in second quarter 2017 and we are continuing to wind down our U.S. power marketing operations. See Significant Events section for more details.

Canadian 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.

A disciplined operational strategy is critical to maximizing revenue at our cogeneration facilities and maximizing Coolidge earnings, where revenue is based on plant availability rather than a function of market price.

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 shorter-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 2,900 MW of power generation capacity in Eastern Canada. All of the power produced by these assets is sold under long-term contracts.

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

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 eight nuclear facilities from OPG. We hold a 48.4 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.

In 2015, Bruce Power entered into an agreement with the IESO to extend the operating life of the Bruce Power facility to 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.

Under the amended agreement, which took economic effect in January 2016, Bruce Power has begun investing in life extension activities for Units 3 through 8 to support the long-term refurbishment program. This early investment in the Asset Management program is designed to result in near-term life extension up to the planned major refurbishment outages and beyond. Major Component Replacement (MCR) planning work is currently underway with the first MCR outage on Unit 6 expected in early 2020 and refurbishment of the remaining units planned to continue through 2033.

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 reduces 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.

Our estimated share of investment related to the Asset Management program to be completed over the life of the agreement is approximately $2.5 billion (2014 dollars). Our estimated share of investment in the MCR work for Units 3 through 8 over the 2020 to 2033 timeframe is approximately a further $4 billion (2014 dollars).

Under certain conditions, Bruce Power and the IESO can elect to not proceed with the remaining MCR investments should the cost exceed certain thresholds or prove to not provide sufficient economic benefits.

Over time, the contract price will be subject to adjustments for the return of and on capital invested at Bruce Power under the Asset Management 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 efficiencies with the IESO for better than planned performance.

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

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 business and our regulated 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 the change 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.

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

Canadian Power

Ontario Solar

On October 24, 2017, we entered into an agreement to sell our Ontario solar assets comprised of eight facilities with a total generating capacity of 76 MW. On December 19, 2017, we closed the sale for $541 million resulting in a pre-tax gain of $127 million ($136 million after tax).

Napanee

Construction continues on our 900 MW natural gas-fired power plant at OPG's Lennox site in eastern Ontario in the town of Greater Napanee. We expect to invest approximately $1.3 billion in the Napanee facility and commercial operations are expected to begin in fourth quarter 2018. Costs have increased due to delays in the construction schedule. Once in service, production from the facility is fully contracted with the IESO for a 20-year period.

U.S. Power

Monetization of U.S. Northeast power business

In April 2017, we closed the sale of TC Hydro for US$1.07 billion, before post-closing adjustments and recorded a gain of approximately $715 million ($440 million after tax).

In June 2017, we closed the sale of Ravenswood, Ironwood, Ocean State Power and Kibby Wind for US$2.029 billion, before post-closing adjustments. In addition to pre-tax losses of approximately $829 million ($863 million after tax) 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. The transaction is expected to close in the first quarter of 2018 subject to regulatory and other approvals.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 and 2015 results have been adjusted to reflect this change.

year ended December 31 (millions of $)	2017	2016	2015
Canadian Power			
Western Power[1]	**100**	74	71
Eastern Power	**344**	349	389
Bruce Power	**434**	293	285
Canadian Power – comparable EBITDA[1,2]	**878**	716	745
Depreciation and amortization	**(138)**	(145)	(193)
Canadian Power – comparable EBIT	**740**	571	552
U.S. Power – comparable EBITDA[3] (US$)	**100**	394	411
Depreciation and amortization[4]	**—**	(109)	(106)
U.S. Power – comparable EBIT (US$)	**100**	285	305
Foreign exchange impact	**30**	92	85
U.S. Power – comparable EBIT (Cdn$)	**130**	377	390
Natural Gas Storage and other operations – comparable EBITDA	**55**	58	14
Depreciation and amortization	**(13)**	(12)	(13)
Natural Gas Storage and other operations – comparable EBIT	**42**	46	1
Business Development and other costs – comparable EBITDA and EBIT[5]	**(33)**	(15)	(30)
Energy – comparable EBIT	**879**	979	913
Specific items:			
Gain/(loss) on sales of U.S. Northeast power assets	**484**	(844)	—
Gain on sale of Ontario solar assets	**127**	—	—
Ravenswood goodwill impairment	**—**	(1,085)	—
Alberta PPA terminations and settlement	**—**	(332)	—
Turbine equipment impairment charge	**—**	—	(59)
Bruce Power merger – debt retirement charge	**—**	—	(36)
Risk management activities	**62**	125	(37)
Segmented earnings/(loss)	**1,552**	(1,157)	781

1 Included 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 TC Hydro earnings included up to April 19, 2017 sale date; Ravenswood, Ironwood, Ocean State Power and Kibby Wind earnings included up to June 2, 2017 sale date.
4 Depreciation of U.S. Northeast power assets ceased effective November 2016 when classified as assets held for sale.
5 Includes a $21 million impairment charge in 2017 related to obsolete equipment.

Energy segmented earnings were $2,709 million higher in 2017 than in 2016 and $1,938 million lower in 2016 than in 2015 and included the following specific items:

- a net gain in 2017 of $484 million (2016 - loss of $844 million) before tax related to the monetization of our U.S. Northeast power 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. See Significant Events section for more details
- a gain in 2017 of $127 million before tax related to the sale of our Ontario solar assets. See Significant Events section for more details
- a $1,085 million 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
- a loss in 2015 of $59 million before tax relating to an impairment in value of turbine equipment previously purchased for a power development project that did not proceed
- a charge in 2015 of $36 million before tax related to Bruce Power's retirement of debt in conjunction with the merger of the Bruce A and Bruce B partnerships
- unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain commodity price risks as follows:

Risk management activities			
(millions of $, pre-tax)	**2017**	**2016**	**2015**
Canadian Power	**11**	4	(8)
U.S. Power	**39**	113	(30)
Natural Gas Storage	**12**	8	1
Total unrealized gains/(losses) from risk management activities	**62**	125	(37)

The variances in these unrealized gains and losses reflect the impact of changes in forward natural gas and power prices and the volume of our positions for these particular derivatives over a certain period of time; however, they do not accurately reflect the gains and losses that will be realized on settlement, or the offsetting impact of other derivative and non-derivative transactions that make up our business as a whole. As a result, we do not consider them representative of our underlying operations.

The specific items noted above have been excluded in our calculation of comparable EBIT. The remainder of the Energy segmented earnings are equivalent to comparable EBIT which, along with comparable EBITDA, are discussed below.

Comparable EBITDA for Energy was $1,030 million in 2017 compared to $1,281 million in 2016, a decrease of $251 million, primarily due to the net effect of:

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

Comparable EBITDA for Energy was $1,281 million in 2016 compared to $1,254 million in 2015, an increase of $27 million, primarily due to the net effect of:

- higher earnings from Natural Gas Storage due to higher realized natural gas storage price spreads
- lower earnings from Eastern Power due to lower contractual earnings at Bécancour and lower contributions from the sale of unused natural gas transportation
- lower earnings from U.S. Power
- lower business development expenses primarily due to decreased business development activity
- higher earnings from Bruce Power mainly due to lower depreciation as a result of the operating life extensions, our increased ownership interest and higher realized sales price, partially offset by lower volumes and higher operating costs from increased outage days
- a stronger U.S. dollar and its positive effect on the foreign exchange impact.

Western and Eastern Power results

Western Power

Western Power comparable EBITDA in 2017 was $26 million higher than in 2016 mainly due to the termination of the Alberta PPAs. Results from the Alberta PPAs are included up to March 7, 2016 when we terminated the PPAs for the Sundance A, Sundance B and Sheerness facilities.

In 2016, Western Power comparable EBITDA was $3 million higher than in 2015 due to higher realized prices on generated volumes offset by PPA losses realized in first quarter 2016.

Eastern Power

Eastern Power comparable EBITDA in 2017 was $5 million lower than 2016 mainly due to lower earnings on the sale of unused natural gas transportation.

In 2016, Eastern Power comparable EBITDA was $40 million lower than 2015 due to lower contractual earnings at Bécancour and lower earnings on the sale of unused natural gas transportation.

Depreciation and amortization

Depreciation and amortization decreased by $7 million in 2017 compared to 2016 and $48 million in 2016 compared to 2015 following the termination of the Alberta PPAs in March 2016.

Bruce Power results

Bruce Power results reflect our proportionate share. Bruce A and B were merged in December 2015 and comparative information for 2015 is reported on a combined basis to reflect the merged entity. Comparable EBITDA and comparable EBIT are non-GAAP measures. See 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)	2017	2016	2015
Equity income included in comparable EBITDA and EBIT comprised of:			
Revenues	**1,626**	1,491	1,317
Operating expenses	**(846)**	(870)	(707)
Depreciation and other	**(346)**	(328)	(325)
Comparable EBITDA and comparable EBIT[1]	**434**	293	285
Bruce Power – other information			
Plant availability[2]	**90%**	83%	87%
Planned outage days	**221**	415	327
Unplanned outage days	**49**	76	45
Sales volumes (GWh)[1]	**24,368**	22,178	19,358
Realized sales price per MWh[3]	**$67**	$68	$66

1 Represents our 48.4 per cent (2016 - 48.5 per cent) ownership interest in Bruce Power after the merger on December 4, 2015 and, prior to this, represents our 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B. Sales volumes include deemed generation. Comparable EBITDA in 2015 excludes a $36 million debt retirement charge.

2 The percentage of time the plant was available to generate power, regardless of whether it was running.

3 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.

Bruce Power comparable EBITDA in 2017 was $141 million higher than 2016 mainly due to higher volumes resulting from fewer outage days.

In 2016, Bruce Power comparable EBITDA was $8 million higher than 2015 mainly due to lower depreciation as a result of the Bruce Power facility's operating life extension, our increased ownership and higher realized sales prices, partially offset by lower volumes and higher operating costs from increased outage days compared to 2015.

U.S. Power results

In second quarter 2017, we completed the sales of our U.S. Power generation assets and initiated the wind down of our U.S. power marketing operations. See Significant Events section for more details.

U.S. Power's comparable EBITDA in 2016 was US$17 million lower than 2015, primarily due to the net effect of:

- lower capacity revenues due to lower realized capacity prices in New York and the impact of lower availability as a result of a unit outage from September 2014 to May 2015, partially offset by insurance recoveries, net of deductibles at Ravenswood
- lower realized power prices and lower generation at our facilities in New England, partially offset by lower fuel costs
- lower margins on sales to wholesale, commercial and industrial customers partially offset by higher sales to customers in the PJM market
- higher earnings due to our acquisition of the Ironwood power plant in February 2016
- insurance recoveries related to an unplanned outage at the Ravenswood facility that occurred in 2008.

Natural Gas Storage and other operating results

Natural Gas Storage comparable EBITDA in 2017 was $3 million lower than 2016 primarily due to lower realized natural gas storage price spreads.

In 2016, Natural Gas Storage comparable EBITDA was $44 million higher than 2015 mainly due to higher realized natural gas storage price spreads.

OUTLOOK

Earnings

Our 2018 comparable earnings for the Energy segment are expected to be lower than 2017 primarily due to the monetization of the U.S. Northeast power generation assets in second quarter 2017 and the Ontario solar assets in late 2017, the continuing wind down of our U.S. Power marketing operations and higher planned outages at Bruce Power, partially offset by incremental earnings from the expected completion of the Napanee power plant in Ontario.

Following the monetization of the U.S. Northeast power business, the vast majority of Energy's remaining output is sold under long-term contracts.

Western Power earnings in 2018 are expected to be slightly higher than in 2017 due to an increase in forecast average spot power prices and a modest increase in generation.

Eastern Power earnings in 2018 are expected to be slightly lower than in 2017 due to the sale of our Ontario solar assets in 2017, partially offset by the completion of our Napanee power plant which is expected to begin commercial operations in fourth quarter 2018.

Bruce Power equity income in 2018 is expected to be lower than in 2017 due to higher planned outages. Planned maintenance is expected to occur on Bruce Units 1 and 4 in the first half of 2018 and Units 3 and 8 in the second half of 2018. The average plant availability percentage in 2018 is expected to be in the high 80 per cent range compared to 90 per cent in 2017.

Natural Gas Storage earnings in 2018 are expected to be lower than in 2017 due to lower expected realized storage spreads.

Capital spending

We spent a total of $0.4 billion in 2017 and expect to spend approximately $0.5 billion on capital projects in Energy in 2018, primarily on Napanee.

We invested $0.3 billion for capital and maintenance projects at Bruce Power in 2017 and expect to invest approximately $0.5 billion in 2018.

BUSINESS RISKS

The following are risks specific to our Energy business. See page 83 for information about general risks that affect the Company as a whole, including other operational risks, HSE risks, and financial risks.

Fluctuating power and natural gas market prices

Our portfolio of assets in Eastern Canada and our Coolidge facility 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 mitigated through long-term contracts and hedging activities. 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.

Plant availability

Optimizing and maintaining plant availability is 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 other weather events 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. Variable wind speeds affect earnings from our wind assets.

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 the greenfield power plant development arena.

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented losses (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. Certain costs previously reported in our Corporate segment are now being reported within the business segments as a result of our 2015 business transformation initiative. 2016 and 2015 results have been adjusted to reflect this change.

year ended December 31 (millions of $)	2017	2016	2015
Comparable EBITDA and EBIT	**(21)**	18	(53)
Specific items:			
Integration and acquisition related costs – Columbia	**(81)**	(116)	—
Foreign exchange gain – inter-affiliate loan[1]	**63**	—	—
Restructuring costs	**—**	(22)	(99)
Segmented losses	**(39)**	(120)	(152)

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

Corporate segmented losses were $81 million lower in 2017 compared to2016 and $32 million lower in 2016 compared to 2015.

Segmented losses in 2017 included pre-tax integration and acquisition costs of $81 million (2016 – $116 million) associated with the acquisition of Columbia and a $63 million foreign exchange gain 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 2016 and 2015 included restructuring costs of $22 million and $99 million, respectively, as described below. These amounts have been excluded from our calculation of comparable EBITDA and EBIT.

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

Comparable EBITDA increased by $71 million in 2016 compared to 2015 primarily due to the 2015 inclusion of the portion of our corporate restructuring costs recovered through our tolling mechanisms.

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 of this initiative, we began to incur restructuring costs, consisting primarily of severance and expected future losses under lease commitments, and recorded a provision of $87 million before tax to allow for planned severance costs for 2016 and 2017, as well as expected future losses under lease commitments. In 2016 and 2017, we recorded additional provisions to reflect changes in our expected future losses under lease commitments. Changes in the restructuring liability were as follows:

(millions of $)	Employee Severance	Lease Commitments	Total
Restructuring liability as at December 31, 2015	60	27	87
Restructuring charges	—	44	44
Cash payments	(24)	(8)	(32)
Restructuring liability as at December 31, 2016	36	63	99
Restructuring charges	—	6	6
Cash payments	(27)	(16)	(43)
Restructuring Liability as at December 31, 2017	**9**	**53**	**62**

The remaining employee severance provision at December 31, 2017 is expected to be settled in early 2018.

Cumulatively to December 31, 2017, we have incurred costs, net of amounts recoverable through regulatory and tolling structures, of $86 million for employee severance and $38 million for lease commitments under this initiative.

OTHER INCOME STATEMENT ITEMS

Interest Expense

year ended December 31 (millions of $)	2017	2016	2015
Interest on long-term debt and junior subordinated notes			
Canadian dollar-denominated	**(494)**	(452)	(437)
U.S. dollar-denominated	**(1,269)**	(1,127)	(911)
Foreign exchange impact	**(379)**	(366)	(255)
	(2,142)	(1,945)	(1,603)
Other interest and amortization expense	**(99)**	(114)	(47)
Capitalized interest	**173**	176	280
Interest expense included in comparable earnings	**(2,068)**	(1,883)	(1,370)
Specific items:			
Integration and acquisition related costs – Columbia	**—**	(115)	—
Risk management activities	**(1)**	—	—
Interest expense	**(2,069)**	(1,998)	(1,370)

Interest expense in 2017 was $71 million higher than in 2016 primarily due to the net effect of:

- long-term debt and junior subordinated notes issuances in 2017 and 2016, partially offset by Canadian and U.S. dollar-denominated debt maturities. See 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.

Interest expense in 2016 was $628 million higher than 2015 mainly due to the net effect of:

- the specific item of $115 million in 2016 discussed above
- long-term debt issuances in 2016 and 2015, partially offset by Canadian and U.S. dollar-denominated debt maturities
- debt assumed in the acquisition of Columbia on July 1, 2016
- higher foreign exchange on interest expense related to a weaker Canadian dollar and higher levels of U.S. dollar-denominated debt
- amortization expense on debt issuance costs related to the Columbia acquisition bridge facilities
- higher carrying charges to shippers in 2016 on the net revenue variance for the Canadian Mainline
- lower capitalized interest on Keystone XL and related projects following the November 6, 2015 denial of a U.S. Presidential Permit, partially offset by higher capitalized interest on liquids projects, LNG projects and Napanee.

Allowance for funds used during construction

year ended December 31 (millions of $)	2017	2016	2015
Allowance for funds used during construction			
Canadian dollar-denominated	**174**	181	119
U.S. dollar-denominated	**259**	181	137
Foreign exchange impact	**74**	57	39
Allowance for funds used during construction	**507**	419	295

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.

AFUDC in 2016, was $124 million higher than 2015 due to capital expenditures on our Mexico pipelines, Energy East and NGTL System expansion projects.

Interest income and other

year ended December 31 (millions of $)	2017	2016	2015
Interest income and other included in comparable earnings	**159**	71	(111)
Specific items:			
Integration and acquisition related costs – Columbia	**—**	6	—
Foreign exchange loss - inter-affiliate loan	**(63)**	—	—
Risk management activities	**88**	26	(21)
Interest income and other	**184**	103	(132)

In 2017, interest income and other was$81 million higher than 2016 due to the net effect of:

- higher unrealized gains on risk management activities in 2017 compared to 2016. These amounts have been excluded from comparable earnings
- recovery of $32 million related to carrying charges on Coastal GasLink project costs incurred and recognized on the termination of the PRGT project. See the Canadian Natural Gas Pipelines Significant events section for more information
- 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 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. Both currency-related amounts are excluded from comparable earnings.

In 2016, interest income and other was $235 millionhigher than 2015 due to the net effect of:

- realized gains in 2016 compared to realized losses in 2015 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- unrealized gains on risk management activities in 2016 compared to losses in 2015. These amounts have been excluded from comparable earnings
- foreign exchange impact on the translation of foreign currency denominated working capital
- interest income on the gross proceeds of the subscription receipts issued to partially fund the Columbia acquisition. These amounts have been excluded from comparable earnings.

Income tax expense

year ended December 31 (millions of $)	2017	2016	2015
Income tax expense included in comparable earnings	**(839)**	(841)	(903)
Specific items:			
U.S. Tax Reform adjustment	**804**	—	—
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	—
Net gain on sales of U.S. Northeast power assets	**(177)**	(29)	—
Ravenswood goodwill impairment	**—**	429	—
Alberta PPA terminations and settlement	**—**	88	—
Restructuring costs	**—**	6	25
TC Offshore loss on sale	**—**	1	39
Keystone XL impairment charge	**—**	—	795
Turbine equipment impairment charge	**—**	—	16
Bruce Power merger – debt retirement charge	**—**	—	9
Alberta corporate income tax rate increase	**—**	—	(34)
Risk management activities	**(45)**	(54)	19
Income tax recovery/(expense)	**89**	(352)	(34)

Income tax expense included in comparable earnings in 2017 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.

Income tax expense included in comparable earnings decreased by $62 million in 2016 compared to 2015 mainly due to lower flow-through taxes in 2016 on Canadian regulated pipelines and changes in the proportion of income earned between Canadian and foreign jurisdictions, partially offset by higher pre-tax earnings in 2016 compared to 2015.

Net income attributable to non-controlling interests

year ended December 31 (millions of $)	2017	2016	2015
Net income attributable to non-controlling interests included in comparable earnings	**(238)**	(257)	(205)
Specific items:			
Acquisition related costs – Columbia	**—**	5	—
TC PipeLines, LP – Great Lakes impairment	**—**	—	199
Net income attributable to non-controlling interests	**(238)**	(252)	(6)

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.

In 2016, net income attributable to non-controlling interests increased by $246 million compared to2015 due to the net effect of a $5 million charge in 2016 related to the non-controlling interests' portion of retention and severance expenses resulting from the Columbia acquisition and a US$199 million impairment charge recorded by TC PipeLines, LP in 2015 related to its equity investment in Great Lakes. Both of these items were excluded in the calculation of comparable earnings. On consolidation, we reversed the non-controlling interests' 72 per cent of this TC PipeLines, LP impairment charge, which was US$143 million or $199 million in Canadian dollars. TC PipeLines, LP's impairment charge was not recognized at the TransCanada consolidation level as a result of our lower carrying value of Great Lakes. See the Critical accounting estimates section for more information on our goodwill impairment testing.

In 2016, net income attributable to non-controlling interests included in comparable earnings increased by $52 million compared to 2015 primarily due to the acquisition of Columbia, which brought with it a non-controlling interest in CPPL. The sale of our 30 per cent direct interest in GTN in April 2015 and a 49.9 per cent interest in PNGTS in January 2016 to TC PipeLines, LP, along with the impact of a stronger U.S. dollar on the Canadian dollar equivalent earnings from TC PipeLines, LP also contributed to increased net income attributable to non-controlling interests year-over-year.

Preferred share dividends

year ended December 31 (millions of $)	2017	2016	2015
Preferred share dividends	**(160)**	(109)	(94)

Preferred share dividends declared 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. See 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 Annual Information Form available on SEDAR (www.sedar.com).

We believe we have the financial capacity to fund our existing capital program through predictable and growing cash flow from operations, access to capital markets (including through our ATM equity issuance programs, as appropriate), our DRP, portfolio management including proceeds we receive from TC PipeLines, LP in exchange for the drop down of natural gas pipeline assets, cash on hand and substantial committed credit facilities. The drop down of our U.S. natural gas pipeline assets into TC PipeLines, LP remains an important financing option for us as we execute our capital growth program, subject to actual funding needs, market conditions, the relative attractiveness of alternate capital sources, as well as the approvals of TC PipeLines, LP's Board of Directors and our Board of Directors (the Board).

Balance sheet analysis

Our total assets at December 31, 2017 were $86.1 billion compared to $88.1 billion at December 31, 2016. The decrease primarily reflects the sales of our U.S. Northeast power assets to repay bridge facilities drawn to complete the acquisition of Columbia in 2016, and the impairment of Energy East and related projects. These amounts were partially offset by continued capital investment.

At December 31, 2017, our total liabilities were $59.2 billion compared to $60.9 billion at December 31, 2016. The decrease mainly reflects a net reduction in long-term debt, primarily as a result of retirement of the remaining Columbia acquisition bridge facilities, partially offset by issuances of junior subordinated notes and increased notes payable.

At December 31, 2017, we no longer have common units subject to rescission or redemption, compared to $1.2 billion at December 31, 2016, as a result of the acquisition of the outstanding publicly held common units of CPPL and the expiration of rescission rights on common units of TC PipeLines, LP.

Our equity at December 31, 2017 was $26.9 billion compared to $26.0 billion at December 31, 2016. The increase is primarily due to common shares issued under our DRP and corporate ATM program, partially offset by the impact of a stronger Canadian dollar on the translation of our net investment in foreign operations.

Consolidated capital structure

The following table summarizes the components of our capital structure.

at December 31 (millions of $ – unless otherwise noted)	2017	Percent of Total	2016	Percent of total
Notes payable	**1,763**	**3 %**	774	1 %
Long-term debt, including current portion	**34,741**	**50 %**	40,150	57 %
Cash and cash equivalents	**(1,089)**	**(2)%**	(1,016)	(1)%
Debt	**35,415**	**51 %**	39,908	57 %
Junior subordinated notes	**7,007**	**10 %**	3,931	6 %
Preferred shares	**3,980**	**6 %**	3,980	6 %
Common shareholders' equity[1]	**22,911**	**33 %**	22,003	31 %
	69,313	**100 %**	69,822	100 %

1 Includes non-controlling interests.

At December 31, 2017, we had unused capacity of $2.8 billion, $2.0 billion, and US$7.5 billion under our various equity, Canadian debt and U.S. debt shelf prospectuses, respectively, to facilitate future access to capital markets.

We were in compliance with all of our financial covenants atDecember 31, 2017. Provisions of various trust indentures and credit arrangements with certain of our subsidiaries can restrict those subsidiaries' ability to declare and pay dividends or make distributions under certain circumstances. If such restrictions apply, they may, in turn, have an impact on our ability to declare and pay dividends on our common and preferred shares. In the opinion of management, these provisions do not currently restrict or alter 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.

Cash flow

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

year ended December 31 (millions of $)	2017	2016	2015
Net cash provided by operations	**5,230**	5,069	4,384
Net cash used in investing activities	**(3,699)**	(18,783)	(4,879)
	1,531	(13,714)	(495)
Net cash (used in)/provided by financing activities	**(1,419)**	14,007	744
	112	293	249
Effect of foreign exchange rate changes on cash and cash equivalents	**(39)**	(127)	112
Increase in cash and cash equivalents	**73**	166	361

At December 31, 2017, our current assets totaled$4.7 billion (2016 – $8.1 billion) and current liabilities amounted to$9.9 billion (2016 – $7.7 billion), leaving us with a working capital deficit of $5.2 billion compared to a surplus of $0.4 billion at December 31, 2016. The surplus at December 31, 2016 was primarily the result of the pending sale of the U.S. Northeast power assets, the $3.7 billion carrying value of which had been reclassified to assets held for sale within current assets. Without the assets held for sale classification as current on the balance sheet, we would have reported a working capital deficit at December 31, 2016. 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
- our access to capital markets, including through our DRP and ATM programs
- approximately $9.0 billion of unused, unsecured credit facilities.

Cash provided by operating activities

year ended December 31 (millions of $)	2017	2016	2015
Net cash provided by operations	**5,230**	5,069	4,384
Increase/(decrease) in operating working capital	**273**	(248)	346
Funds generated from operations	**5,503**	4,821	4,730
Specific items:			
Integration and acquisition related costs - Columbia	**84**	283	—
Keystone XL asset costs	**34**	52	—
U.S. Northeast power disposition costs	**20**	15	—
Restructuring costs	**—**	—	85
Comparable funds generated from operations	**5,641**	5,171	4,815
Dividends on preferred shares	**(155)**	(100)	(92)
Distributions paid to non-controlling interests	**(283)**	(279)	(224)
Maintenance capital expenditures including equity investments			
– Recoverable in future tolls	**(1,364)**	(941)	(786)
– Other	**(240)**	(310)	(256)
Comparable distributable cash flow			
– Reflecting all maintenance capital expenditures	**3,599**	3,541	3,457
– Reflecting only non-recoverable maintenance capital expenditures	**4,963**	4,482	4,243
Comparable distributable cash flow per common share			
– Reflecting all maintenance capital expenditures	**$4.13**	$4.67	$4.88
– Reflecting only non-recoverable maintenance capital expenditures	**$5.69**	$5.91	$5.98

Net cash provided by operations

The year-over-year increases in net cash provided by operations are primarily due to higher comparable earnings (as discussed in Financial highlights on page 21) and 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. See page 8 for more information about non-GAAP measures.

Comparable funds generated from operations increased by $470 million in 2017 compared to 2016, primarily 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 funds generated from operations increased by $356 million in 2016 compared to 2015 mainly due to higher comparable EBITDA (excluding income from equity investments) and higher interest income and other primarily due to realized gains in 2016 against losses in 2015 and higher distributions from our equity investments, partially offset by higher interest expense on debt incurred for and assumed in the Columbia acquisition, lower capitalized interest on Keystone XL and higher 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. See 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, partially offset by higher recoverable maintenance capital expenditures in Canadian and U.S. natural gas pipelines. Comparable distributable cash flow per common share for the year ended December 31, 2017 also includes the dilutive effect of common shares issued in 2016 and 2017.

Although we deduct maintenance capital expenditures in determining comparable distributable cash flow, we have the ability to recover the majority of these costs in Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Liquids Pipelines. Canadian natural gas pipelines maintenance capital expenditures are reflected in rate bases, on which we earn a regulated return and subsequently recover in tolls. Almost all of our U.S. natural gas pipelines can recover maintenance capital through tolls under current rate settlements, or have the ability to recover maintenance capital through tolls established in future rate cases or settlements. Tolling arrangements in Liquids Pipelines provide for recovery of maintenance capital.

The following table provides a breakdown of maintenance capital expenditures.

year ended December 31 (millions of $)	2017	2016	2015
Canadian Natural Gas Pipelines	**601**	323	347
U.S. Natural Gas Pipelines	**749**	586	381
Liquids Pipelines	**19**	32	58
Other	**235**	310	256
Maintenance capital expenditures including equity investments	**1,604**	1,251	1,042

Cash used in investing activities

year ended December 31 (millions of $)	2017	2016	2015
Capital spending			
Capital expenditures	**(7,383)**	(5,007)	(3,918)
Capital projects in development	**(146)**	(295)	(511)
Contributions to equity investments	**(1,681)**	(765)	(493)
	(9,210)	(6,067)	(4,922)
Acquisitions, net of cash acquired	**—**	(13,608)	(236)
Proceeds from sale of assets, net of transaction costs	**5,317**	6	—
Other distributions from equity investments	**362**	727	9
Deferred amounts and other	**(168)**	159	270
Net cash used in investing activities	**(3,699)**	(18,783)	(4,879)

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. power generation assets and solar assets in 2017
- recovery of PRGT project costs.

Net cash used in investing activities increased from$4.9 billion in 2015 to $18.8 billion in 2016 primarily as a result of the acquisitions of Columbia and Ironwood along with higher capital spending, partially offset by increased distributions received from Bruce Power related to its debt issuances.

Capital Spending[1]

The following table summarizes capital spending by segment.

year ended December 31 (millions of $)	2017	2016	2015
Canadian Natural Gas Pipelines	**2,181**	1,525	1,596
U.S. Natural Gas Pipelines	**3,830**	1,522	537
Mexico Natural Gas Pipelines	**1,954**	1,142	566
Liquids Pipelines	**529**	1,137	1,601
Energy	**675**	708	558
Corporate	**41**	33	64
	9,210	6,067	4,922

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

Capital expenditures

Capital expenditures in 2017 were incurred primarily for the expansion of the Columbia Gas, Columbia Gulf, NGTL System and Canadian Mainline natural gas pipelines, the construction of Mexican natural gas pipelines and the Napanee power generating facility, as well as capital additions to and maintenance of our ANR pipeline.

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 Mexican natural gas pipelines, Northern Courier pipeline and the Napanee power generating facility.

Our 2015 capital expenditures were incurred primarily for expanding the NGTL System, Canadian Mainline and ANR, plus construction of our Mexican natural gas pipelines, Northern Courier pipeline and the Napanee power generating facility.

Capital projects in development

Costs incurred on capital projects in development were predominantly related to spending on the Energy East and LNG-related pipeline projects in each year.

Contributions to equity investments

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 into service in August 2017. Contributions to equity investments in 2017 also includes our proportionate share of Sur de Texas debt financing.

The increase in contributions to equity investments in 2016 compared to 2015 was primarily due to our investments in Bruce Power, Grand Rapids and Sur de Texas.

Acquisitions and sales of assets

On December 19, 2017, we closed the sale of our Ontario solar assets for proceeds of approximately $541 million, before post-closing adjustments.

On July 25, 2017, we were notified that PNW LNG would not be proceeding with their LNG project. As a result, we received a payment of $0.6 billion from Progress Energy in October 2017 for full recovery of our costs plus carrying charges.

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.

On April 19, 2017, the Company completed the sale of TC Hydro for proceeds of approximately US$1.07 billion, before post-closing adjustments.

In 2016, we completed the following transactions:

- acquired 100 per cent ownership of Columbia for US$10.3 billion in cash
- acquired the Ironwood power plant for US$653 million in cash after post-acquisition adjustments
- acquired an additional 5.52 per cent interest in Iroquois for an aggregate purchase price of US$61 million
- sold TC Offshore for $6 million.

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 2017, Bruce Power issued senior notes in capital markets which resulted in distributions totaling $362 million being received by us. In 2016, Bruce Power issued senior notes in the capital markets and borrowed under a bank credit facility which resulted in $725 million being received by us.

Cash (used in)/provided by financing activities

year ended December 31 (millions of $)	2017	2016	2015
Notes payable issued/(repaid), net	**1,038**	(329)	(1,382)
Long-term debt issued, net of issue costs	**3,643**	12,333	5,045
Long-term debt repaid	**(7,085)**	(7,153)	(2,105)
Junior subordinated notes issued, net of issue costs	**3,468**	1,549	917
Dividends and distributions paid	**(1,777)**	(1,815)	(1,762)
Common shares issued, net of issue costs	**274**	7,747	27
Common shares repurchased	**—**	(14)	(294)
Preferred shares issued, net of issue costs	**—**	1,474	243
Partnership units of subsidiary issued, net of issue costs	**225**	215	55
Common units of Columbia Pipelines Partners LP acquired	**(1,205)**	—	—
Net cash (used in)/provided by financing activities	**(1,419)**	14,007	744

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 which, as a transaction between entities under common control, was recorded in equity.

Net cash provided by financing activities increased by $13.3 billion in 2016 compared to 2015 mainly due to issuances of long-term debt (net of long-term debt repaid), common shares, junior subordinated notes and preferred shares in 2016 to support the financing of the Columbia acquisition.

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

Long-term debt issued

In 2017, TCPL issued US$700 million of Senior Unsecured Notes, bearing interest at a fixed rate of 2.125 per cent, as well as an additional US$550 million of Senior Unsecured Notes, bearing interest at a floating rate, due in November 2019.

In 2017, TCPL issued $700 million of Medium Term Notes, due in September 2047, bearing interest at a fixed rate of 4.33 per cent, as well as an additional $300 million of Medium Term Notes, due in March 2028, bearing interest at a fixed rate of 3.39 per cent.

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

In 2017, TC PipeLines, LP issued US$500 million of Senior Unsecured Notes, due in May 2027, bearing interest at a fixed rate of 3.90 per cent. The net proceeds of this debt issuance were primarily used to fund TC PipeLines, LP's acquisition of interests in PNGTS and Iroquois.

For more information about long-term debt issued in 2017, 2016 and 2015, see Note 17, Long-Term Debt, of our consolidated financial statements.

Long-term debt repaid

Proceeds from the sales of our U.S. Northeast power generation assets were used to repay US$3.7 billion of acquisition bridge facilities in 2017. The facilities were initially put into place to finance a portion of the Columbia acquisition.

In 2017, TCPL repaid US$1.0 billion of Senior Unsecured Notes bearing interest at a fixed rate of 1.625 per cent, $300 million of Medium Term Notes bearing interest at a fixed rate of 5.10 per cent and $100 million of Debentures bearing interest at a fixed rate of 9.80 per cent.

In 2018, TCPL repaid US$500 million of Senior Unsecured Notes bearing interest at a fixed rate of 1.875 per cent and US$250 million of Senior Unsecured Notes bearing interest at a floating rate.

For more information about long-term debt repaid in 2017, 2016 and 2015, see Note 17, Long-Term Debt, of our consolidated financial statements.

Junior subordinated notes issued

In May 2017, TransCanada Trust (Trust), a wholly-owned financing trust subsidiary of TCPL, issued $1.5 billion of Trust Notes – Series 2017-B to third party investors at 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, for the first ten years, converting to a floating rate thereafter. 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 March 2017, the Trust issued US$1.5 billion of Trust Notes – Series 2017-A to third party investors at 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, for the first ten years, converting to a floating rate thereafter. 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.

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.

For more information about the junior subordinated notes, see Note 18, Junior Subordinated Notes, of our 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 2017, the participation rate amongst common shareholders was approximately 36 per cent (2016 – 39 per cent), resulting in $791 million (2016 – $363 million) of common equity issued.

TransCanada Corporation ATM Issuance 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 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, will be utilized as appropriate to manage our capital structure over time. The program has an aggregate gross sales limit of $1.0 billion or the U.S. dollar equivalent. In 2017, 3.5 million common shares were issued under the program at an average price of $63.03 per share for gross proceeds of $218 million. Related commissions and fees totaled approximately $2 million, resulting in net proceeds of $216 million.

Common shares issued under public offerings and subscription receipts
In November 2016, we issued 60.2 million common shares at a price of $58.50 each for total proceeds of approximately $3.5 billion. Proceeds from the offering were used to repay a portion of the US$6.9 billion of acquisition bridge facilities which were used to partially fund the closing of the Columbia acquisition.

In April 2016, we issued 96.6 million subscription receipts entitling each holder to receive one common share upon closing of the Columbia acquisition to partially fund the Columbia acquisition at a price of $45.75 each for total proceeds of $4.4 billion. On July 1, 2016, these subscription receipts were automatically exchanged for TransCanada common shares in accordance with the terms of the subscription receipt agreement and were delisted from the TSX. 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 more information about common shares and subscription receipts issued, including dividend equivalent payments, see Note 20, Common Shares, of our consolidated financial statements.

Common shares repurchased
In November 2015, we announced that the TSX had approved our normal course issuer bid (NCIB), which allowed for the repurchase and cancellation of up to 21.3 million of our common shares, representing three per cent of our issued and outstanding common shares. Under the NCIB, which expired in November 2016, we repurchased 7.1 million common shares at an average purchase price of $43.36 per share through the facilities of the TSX, other designated exchanges and published markets in Canada, or through off-exchange block purchases by way of private agreement.

Preferred share issuance, redemption and conversion
No preferred shares were issued in 2017.

In November 2016, we 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 Series 15 preferred shareholders will have the right to convert their Series 15 preferred shares into Series 16 cumulative redeemable first preferred shares on May 31, 2022 and on the last business day of May of every fifth year thereafter.

In April 2016, we 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. The Series 13 preferred shareholders will have the right to convert their Series 13 preferred shares into Series 14 cumulative redeemable first preferred shares on May 31, 2021 and on the last business day of May of every fifth year thereafter.

In February 2016, holders of 1.3 million Series 5 cumulative redeemable first preferred shares exercised their option to convert to Series 6 cumulative redeemable first preferred shares and receive quarterly floating rate cumulative dividends at an annual rate equal to the applicable 90-day Government of Canada treasury bill rate plus 1.54 per cent which will reset every quarter going forward. The fixed dividend rate on the remaining Series 5 preferred shares was reset for five years at 2.263 per cent per annum and will reset every five years going forward.

The net proceeds of the above preferred share offerings were used for general corporate purposes and to reduce short-term indebtedness which was used to fund our capital program.

For more information on preferred shares see Note 21, Preferred Shares, of our consolidated financial statements.

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

At-the-market 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 ATM program.

During 2017, 3.1 million (2016 – 3.1 million) common units were issued under the TC PipeLines, LP ATM program generating net proceeds of approximately US$173 million (2016 – US$164 million). At December 31, 2017, our ownership interest in TC PipeLines, LP was 25.7 per cent (2016 – 26.8 per cent) after issuances under the ATM program and resulting dilution.

In connection with the 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 the filing of its 2015 Annual Report. As a result, it was determined that the purchasers of 1.6 million common units issued from March 8, 2016 to May 19, 2016 under the ATM 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. In 2017, all rescission rights expired and no unitholder claimed or attempted to exercise any rescission rights prior to the expiration date.

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 PNGTS to TC PipeLines, LP. Proceeds from these transactions were US$765 million before post-closing adjustments. Proceeds were comprised of US$597 million in cash and US$168 million representing a proportionate share of Iroquois and PNGTS debt.

In January 2016, we closed the sale of a 49.9 per cent interest in PNGTS to TC PipeLines, LP for US$223 million. Proceeds were comprised of US$188 million in cash and the assumption of US$35 million of a proportional share of PNGTS debt.

Share information

as at February 12, 2018		
Common Shares	**issued and outstanding**	
	885 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**
	11 million	7 million

For more information on preferred shares see Note 21, Preferred Shares, of our consolidated financial statements.

Dividends

year ended December 31			
	2017	**2016**	**2015**
Dividends declared			
per common share	**$2.50**	$2.26	$2.08
per Series 1 preferred share	**$0.8165**	$0.8165	$0.8165
per Series 2 preferred share	**$0.62138**	$0.60648	$0.6299
per Series 3 preferred share	**$0.538**	$0.538	$0.769
per Series 4 preferred share	**$0.46138**	$0.44648	$0.2269
per Series 5 preferred share	**$0.56575**	$0.56575	$1.10
per Series 6 preferred share	**$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**	$1.1875	$0.704
per Series 13 preferred share	**$1.375**	$1.18525	—
per Series 15 preferred share	**$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 12, 2018, we had a total of $10.9 billion of committed revolving and demand credit facilities:

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 for general corporate purposes	December 2022
US$2.0 billion	US$2.0 billion	TCPL	Supports TCPL's U.S. dollar commercial paper program and for general corporate purposes	December 2018
US$1.0 billion	US$0.9 billion	TCPL USA	Used for TCPL USA general corporate purposes, guaranteed by TCPL	December 2018
US$1.0 billion	US$1.0 billion	Columbia	Used for Columbia general corporate purposes, guaranteed by TCPL	December 2018
US$0.5 billion	US$0.5 billion	TAIL	Supports TAIL's U.S. dollar commercial paper program and for general corporate purposes, guaranteed by TCPL	December 2018
Demand senior unsecured revolving credit facilities:				
$1.9 billion	$0.4 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$4.8 billion	Mexican subsidiary	Used for Mexico general corporate purposes, guaranteed by TCPL	Demand

At February 12, 2018, our operated affiliates had an additional $0.5 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, 2017 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Notes payable	1,763	1,763	—	—	—
Long-term debt and junior subordinated notes	41,748	2,866	6,024	4,014	28,844
Operating leases[1]	790	71	145	133	441
Purchase obligations	4,260	2,292	647	310	1,011
	48,561	6,992	6,816	4,457	30,296

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

Long-term debt and junior subordinated notes

At the end of 2017, we had $34.7 billion of long-term debt and $7.0 billion of junior subordinated notes outstanding, compared to $40.2 billion of long-term debt and $3.9 billion of junior subordinated notes at December 31, 2016.

Total notes payable was $1.8 billion at the end of 2017 compared to $0.8 billion at the end of 2016.

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

Interest payments

At December 31, 2017, scheduled interest payments related to our long-term debt and junior subordinated notes were as follows:

at December 31, 2017 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Long-term debt	21,364	1,722	3,071	2,586	13,985
Junior subordinated notes	23,047	374	750	750	21,173
	44,411	2,096	3,821	3,336	35,158

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)[1]

at December 31, 2017 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Canadian Natural Gas Pipelines					
Transportation by others[2]	889	82	161	139	507
Capital spending[3]	307	306	1	—	—
U.S. Natural Gas Pipelines					
Transportation by others[2]	762	156	184	117	305
Capital spending[3]	397	387	9	1	—
Mexico Natural Gas Pipelines					
Capital spending[3]	743	687	56	—	—
Liquids Pipelines					
Capital spending[3]	70	70	—	—	—
Other	26	5	9	6	6
Energy					
Commodity purchases	243	156	87	—	—
Capital spending[3]	434	378	56	—	—
Other[4]	306	31	47	36	192
Corporate					
Capital spending[3]	83	34	37	11	1
	4,260	2,292	647	310	1,011

1 The amounts in this table exclude funding contributions to our pension plans.

2 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.

3 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.

4 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 $47 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 $47 billion capital program is comprised of $23 billion of near-term projects and $24 billion of commercially supported medium and longer-term projects, 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
- project financing
- preferred shares
- hybrid securities
- additional drop downs of our U.S. natural gas pipeline assets to TC PipeLines, LP
- asset sales
- potential involvement of strategic or financial partners
- common shares issued under our DRP
- common shares issued under our ATM programs, as appropriate
- lastly, discrete common equity issuances.

GUARANTEES

Sur de Texas

We and our partner on the Sur de Texas pipeline, IEnova, have jointly guaranteed the obligations for construction services during the construction of the pipeline. The guarantees have terms ranging to 2020.

At December 31, 2017, our share of potential exposure under the Sur de Texas pipeline guarantees was estimated to be $315 million. The carrying amount of the guarantee was approximately $2 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 2018.

At December 31, 2017, our share of the potential exposure under the Bruce Power guarantee was estimated to be $88 million. The carrying amount of the guarantee was approximately $1 million.

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, 2017 to be $104 million. The carrying amount of these guarantees was approximately $13 million. In some cases, if we make a payment that exceeds our ownership interest, the additional amount must be reimbursed by our partners.

The carrying value of these guarantees has been included in other long-term liabilities.

OBLIGATIONS – PENSION AND OTHER POST-RETIREMENT PLANS

In 2018, we expect to make funding contributions of approximately $98 million for the defined benefit pension plans, approximately $7 million for other post-retirement benefit plans and approximately $45 million for the savings plan and defined contribution pension plans. In addition, we expect to provide a $27 million letter of credit to the Canadian defined benefit plan for solvency funding requirements.

In 2017, we made funding contributions of $163 million to our defined benefit pension plans, $7 million for the other post-retirement benefit plans and $42 million for the savings plan and defined contribution pension plans. We also provided a $27 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, 2018. Based on current market conditions, we expect funding requirements for these plans to approximate 2017 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 $106 million in 2017 from $116 million in 2016 mainly due to higher expected returns on plan assets, partially offset by 2017 settlement charges.

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

RISKS AND 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 in line with our business objectives and risk tolerance.

We manage risk through a centralized assessment process that identifies and allows us to qualify risk that could materially impact our strategic objectives. Risk assessment is built into our decision-making processes at all levels.

Our Board of Directors' Governance Committee oversees our risk management activities, which includes ensuring appropriate management systems are in place to 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 Health, Safety and Environment Committee oversees operational, safety and environmental risk
- the Audit Committee oversees management's role in monitoring 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 general risks that affect our company. 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 labour disputes, equipment malfunctions or breakdowns, acts of terror and sabotage, or natural disasters and other catastrophic events, including those related to climate change.	Decrease in revenues, increase in operating costs or legal proceedings or other expenses all of which could reduce our earnings. Losses not covered by insurance could have an adverse effect on operations, cash flow and financial position.	We have incident, emergency and crisis management systems to ensure an effective response to minimize further loss or injuries and to enhance our ability to resume operations. We also have a Business Continuity Program that determines critical business processes and develops resumption plans to ensure process continuity. We have comprehensive insurance to mitigate certain of these risks, but insurance does not cover all events in all circumstances.
Reputation and relationships		
Our operations and growth prospects require us to have strong relationships with key stakeholders including 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, and continue to access sources 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 the energy infrastructure business, future access to investment capital could be negatively impacted.	Our Stakeholder Engagement Framework guides our engagement activities with stakeholders. 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 ensure compliance with legal and policy requirements.
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 consider the expected cost of our capital projects, under some contracts, 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 TransCanada's Operational Management System that 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 and cost overruns occur. However, under some contracts, we share or bear the cost of execution risk.

Risk and Description	Impact	Monitoring and Mitigation
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, 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 covers reasonably foreseeable losses due to damage to our facilities, and losses incurred by others, as a result of a cyber security event.

Health, safety and environment

The Board's Health, Safety and Environment (HSE) committee oversees operational risk, people and process safety, security of personnel and environmental risks, and monitors compliance with our HSE programs 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 HSE committee reviews HSE performance and operational risk management. It receives detailed reports on:

- overall HSE 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.

Health and safety

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

In 2017, we spent $1.1 billion for pipeline integrity on the Natural Gas and Liquids pipelines we operate, a $252 million increase over 2016 due to an increase of in-line pipeline inspections and enhanced system availability. Additionally, 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 and maintenance activities.

Our Energy operations spending associated with process safety, and various integrity programs, is used to minimize risk to employees and the public, equipment, the 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 and 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, the 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. We are fully cooperating with PHMSA on all matters relating to this incident and the Amherst CAO. Other than the Amherst CAO, 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 interpretation and enforcement of them) 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 investigation or agreements
- we may find new contaminated sites, 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, 2017, accruals related to these obligations totaled $34 million (2016– $39 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 2017, we incurred $63 million (2016 – $62 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 lead to actual resolutions, allowing for sustainable and economically responsible natural resource development, but are appropriately flexible to adapt to economic realities and unintended outcomes. 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

- 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
- B.C. has a tax on GHG emissions from fossil fuel combustion. We recover the compliance costs through the tolls our customers pay
- under the SGER in Alberta, established industrial facilities with GHG emissions above a certain threshold are required to reduce their emissions below an intensity baseline. The SGER program covers our natural gas pipelines and Energy assets. 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 and California have GHG cap and trade programs linked 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 were recovered through commercial contracts. The Canadian Mainline natural gas pipeline facilities in Québec are also subject to this program and have purchased compliance instruments. In California, TransCanada has costs associated with the cap and trade program from our electricity marketing activities
- Ontario launched a cap and trade program under the WCI on January 1, 2017. The Canadian Mainline natural gas pipeline facilities in Ontario are subject to this program and have purchased compliance instruments which are recoverable in tolls. Although TransCanada's electricity generation facilities in the province are not directly subject to this program, TransCanada contributes to the compliance costs through distribution rates
- 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.

Anticipated policies

- future legislative and regulatory programs could significantly restrict emissions of GHGs including methane across our operations
- the Government of Canada has proposed a federal plan to have carbon pricing in place in all Canadian jurisdictions in 2018. The plan would expand GHG pricing coverage of TransCanada assets to Saskatchewan, Manitoba and New Brunswick and is within the bounds of our previously anticipated changes to GHG regulations
- the Alberta government announced a climate change policy, the Climate Leadership Plan (CLP), in 2015. This policy will see the replacement of the SGER program with the Carbon Competitiveness Incentive Regulation, a performance standard-based GHG pricing program, on January 1, 2018
- Environment and Climate Change Canada issued a draft Methane Reduction Regulation on May 27, 2017. The draft regulations detail requirements to reduce methane emissions through operational and capital modifications
- the Government of Canada has proposed a federal plan, the Clean Fuel Standard, to implement a single national standard encompassing all fuel types and applications
- the Pennsylvania Department of Environmental Protection has proposed new operating permits for oil and gas facilities that include numerous requirements including methane leak detection and repair
- New York State announced its intent to adopt regulations to reduce methane from existing, new and modified facilities
- Maryland announced its intent to establish fugitive methane regulations for compressor stations
- the Government of Mexico has proposed to implement a carbon tax for all companies that exceed an annual emissions threshold
- the Saskatchewan and Manitoba governments each announced that large industrial emitters will be subject to a yet to be developed carbon pricing system.

Financial risks

We are exposed to market risk, counterparty credit risk and liquidity risk, and have strategies, policies and limits in place to mitigate their impact on our earnings, cash flow and, ultimately, shareholder value.

These strategies, policies and limits are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance. We manage market risk and counterparty credit risk within limits that are ultimately established by the Board, implemented by senior management and monitored by our risk management and internal audit groups. Management monitors compliance with market and counterparty risk management policies and procedures, and reviews the adequacy of the risk management framework, overseen by the Audit Committee. Our internal audit group assists the Audit Committee by carrying out regular and ad-hoc reviews of risk management controls and procedures, and reporting up to the Audit Committee.

Market risk

We build and invest in energy infrastructure projects, buy and sell energy 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 include:

- forwards and futures contracts – agreements to buy or sell a 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 give the purchaser the right (but not the obligation) 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.

Power generation commodity price risk

We are exposed to commodity price movements as part of our normal business operations. A number of strategies are used to manage these exposures, including the following:

- committing a portion of expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to manage operational and price risks in our asset portfolio
- purchasing a portion of the natural gas required to fuel certain of our power plants or entering into contracts that base the sale price of electricity on the cost of natural gas, effectively locking in a margin
- meeting power sales commitments using power generation or fixed price purchase contracts, thereby reducing our exposure to fluctuating commodity prices.

In April and June 2017, we sold our U.S. Northeast power generation assets and in December 2017, we entered into an agreement to sell our outstanding U.S. power retail contracts as part of the continued wind down of our U.S. power marketing operations. The U.S. power retail contracts transaction is expected to close in the first quarter of 2018 subject to regulatory and other approvals. As a result of these sales, our exposure to commodity price risk has been reduced.

Natural gas storage commodity price risk

We manage our exposure to seasonal natural gas price spreads in the non-regulated natural gas storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. We simultaneously enter into forward purchase contracts of natural gas for injection into storage and offsetting forward sale contracts of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to natural gas price movements. Unrealized gains and losses on fair value adjustments recorded each period on these forward contracts are not necessarily representative of the amounts that will be realized on settlement.

Liquids marketing commodity price risk

The liquids marketing business began operations in 2016. We enter into short-term or long-term liquids pipeline and storage terminal capacity contracts. We fix a portion of our exposure by entering into derivative instruments to manage variable price fluctuations that arise from physical liquids transactions.

Foreign exchange and interest rate 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. The majority of this risk is offset by interest expense on U.S. dollar-denominated debt and by using foreign exchange derivatives.

We are exposed to interest rate risk resulting from financial instruments and contractual obligations containing variable interest rate components. We manage this using a combination of interest rate swaps and options.

Average exchange rate – U.S. to Canadian dollars

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

2017	**1.30**
2016	1.33
2015	1.28

The impact of changes in the value of the U.S. dollar on our U.S. operations is significantly offset by interest on U.S. dollar-denominated debt, as set out in the table below. Comparable EBIT is a non-GAAP measure. See page 8 for more information.

Significant U.S. dollar-denominated amounts

year ended December 31 (millions of US$)	2017	2016	2015
U.S. Natural Gas Pipelines comparable EBIT	**1,360**	947	562
Mexico Natural Gas Pipelines comparable EBIT[1]	**353**	215	130
U.S. Liquids Pipelines comparable EBIT	**604**	482	623
U.S. Power comparable EBIT	**100**	285	305
Interest on U.S. dollar-denominated long-term debt and junior subordinated notes	**(1,269)**	(1,127)	(911)
Capitalized interest on U.S. dollar-denominated capital expenditures	**3**	22	109
U.S. dollar-denominated allowance for funds used during construction	**259**	181	137
U.S. non-controlling interests and other	**182**	189	16
	1,592	1,194	971

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

Net investment hedge

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

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

at December 31 (millions of $)	2017 Fair value[1]	2017 Notional or principal amount	2016 Fair value[1]	2016 Notional or principal amount
U.S. dollar cross-currency interest rate swaps (maturing 2018 to 2019)[2]	**(199)**	**US 1,200**	(425)	US 2,350
U.S. dollar foreign exchange options (maturing 2018)	**5**	**US 500**	—	—
U.S. dollar foreign exchange forward contracts	**—**	**—**	(7)	US 150
	(194)	**US 1,700**	(432)	US 2,500

1 Fair values equal carrying values.

2 In 2017, consolidated net income includes net realized gains of $4 million (2016 – gains of $6 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 $)	2017	2016
Notional amount	**25,400 (US 20,200)**	26,600 (US 19,800)
Fair value	**28,900 (US 23,100)**	29,400 (US 21,900)

Counterparty credit risk

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

- accounts receivable
- the fair value of derivative assets
- cash and cash equivalents.

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 using recognized credit management techniques, including:

- dealing with creditworthy counterparties – a significant amount of our credit exposure is with investment grade counterparties or, if not, is generally partially supported by financial assurances from investment grade parties
- setting limits on the amount we can transact with any one counterparty – we monitor and manage the concentration of risk exposure with any one counterparty, and reduce our exposure when we feel we need to and when it is allowed under the terms of our contracts
- using contract netting arrangements and obtaining financial assurances such as guarantees, letters of credit or cash when we believe it is necessary.

There is no guarantee that these techniques will protect us from material losses.

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At December 312017, we had no significant credit losses, no significant credit risk concentration and no significant amounts past due or impaired. At December 31, 2016, we had a credit risk concentration with one counterparty of $200 million (US$149 million).

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.

For our Canadian regulated natural gas pipeline assets, counterparty credit risk is also managed through application of tariff provisions as approved by the NEB.

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. See Financial condition 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, 2017, 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, 2017, 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, 2017, the internal control over financial reporting was effective.

Our internal control over financial reporting as of December 31, 2017 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 2017 reports filed with Canadian securities regulators and the SEC, and have filed certifications with them.

Changes in internal control over financial reporting

Effective April 1, 2017, management successfully integrated Columbia, which we acquired on July 1, 2016, into our existing enterprise resource planning (ERP) system. As a result of the Columbia ERP system integration, certain processes supporting our internal control over financial reporting for Columbia operations changed in second quarter 2017, however, overall controls and procedures we follow in establishing internal controls over financial reporting were not significantly impacted.

Other than as noted above, 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 the most significant assumptions when preparing our financial statements and changes in these assumptions could have a material impact on the financial statements from those estimates.

Rate-regulated accounting

Under GAAP, an asset qualifies for use of RRA when it meets three criteria:

- a regulator must establish or approve the rates for the regulated services or activities
- the regulated rates must be designed to recover the cost of providing the services or products
- it is reasonable to assume that rates set at levels to recover the cost can be charged to (and collected from) customers because of the demand for services or products and the level of direct and indirect competition.

We believe that the regulated natural gas pipelines projects we account for using RRA meet these criteria. The most significant impact of using these principles is the timing of when we recognize certain expenses and revenues, which is based on the economic impact of the regulators' decisions about our revenues and tolls, and may be different from what would otherwise be expected under GAAP. Regulatory assets represent costs that are expected to be recovered in customer rates in future periods. Regulatory liabilities are amounts that are expected to be returned to customers through future rate setting processes. A decrease in regulatory assets of $27 million and an increase in regulatory liabilities in the amount of $1,659 million were recorded as a result of U.S. Tax Reform. See page 13 for more information.

Regulatory assets and liabilities

at December 31 (millions of $)	2017	2016
Regulatory assets		
Long-term assets	**1,376**	1,322
Short-term assets (included in other current assets)	**23**	33
Regulatory liabilities		
Long-term liabilities	**4,321**	2,121
Short-term liabilities (included in accounts payable and other)	**263**	178

Impairment of long-lived assets, equity investments and goodwill

We review long-lived assets (such as plant, property and equipment), equity investments and intangible assets for impairment whenever events or changes in circumstances lead us to believe we might not be able to recover an asset's carrying value. If the total of the undiscounted future cash flows that we estimate for an asset is less than its carrying value, we consider its fair value to be less than its carrying value and we calculate and record an impairment loss to recognize this. For goodwill, if fair value of the reporting unit is less than carrying value we consider it to be impaired.

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.

In 2016, the following impairments were recorded:

- a goodwill impairment charge on the full carrying value of Ravenswood goodwill of$656 million after tax
- a $244 million after-tax charge with respect to the Alberta PPA terminations.

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 are 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 remaining 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. In 2015, we recognized a non-cash impairment charge of $43 million after tax related to this equipment after evaluating specific capital opportunities and concluding the carrying value was not fully recoverable. The impairment charge was based on the excess of the carrying value over the estimated fair value of the equipment which was determined based on a comparison to similar assets available for sale in the market at that time.

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. TransGas constructed and operated a natural gas pipeline in Colombia for a 20-year build-own-transfer contract term. As per the terms of the agreement, upon completion of the 20-year contract in August 2017, TransGas transfered its pipeline assets to Transportadora de Gas Internacional S.A.. The impairment charge represents the write-down of the remaining carrying value of our equity investment in TransGas.

Alberta PPA terminations

On March 7, 2016, we issued notice to the Balancing Pool of the decision to terminate our Sheerness and Sundance A PPAs. In accordance with a provision in the PPAs, a buyer is permitted to terminate the arrangement if a change in law occurs that makes the arrangement unprofitable or more unprofitable. As a result of recent changes in law surrounding the Alberta SGER, we expected increasing costs related to carbon emissions to continue throughout the remaining terms of the PPAs resulting in increasing unprofitability. As such, in 2016, we recognized a non-cash impairment charge of $155 million after tax, which represented the carrying value of the PPAs. Upon final settlement of the Alberta PPA terminations in December 2016, we 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 $68 million after tax related to the carrying value of these environmental credits.

We also recognized a non-cash impairment charge of $21 million after tax which represented the carrying value of the equity investment in ASTC Partnership, which held the similarly terminated Sundance B PPA.

Keystone XL

At December 31, 2017, we reviewed our remaining investment in Keystone XL and related projects with a carrying value of $475 million (2016 – $526 million) and found no events or changes in circumstance indicating that the carrying value may not be recoverable.

At December 31, 2015, in connection with the denial of the U.S. Presidential permit, we evaluated our $4.3 billion investment in Keystone XL and related projects, including Keystone Hardisty Terminal, for impairment. As a result of our analysis, we determined that the carrying amount of these assets was no longer recoverable, and recognized a total non-cash impairment charge of $3.7 billion ($2.9 billion after tax). The impairment charge was based on the excess of the carrying value over the estimated fair value of $621 million.

The estimated fair value related to plant and equipment at December 31, 2015 was based on the price that would be received to sell the assets in their current condition. Key assumptions used in the determination of selling price included an estimated two-year disposal period and the then current weak energy market conditions. The valuation considered a variety of potential selling prices that were based on the various markets that could be used in order to dispose of these assets.

The estimated fair value of the terminals, including Keystone Hardisty Terminal, at December 31, 2015, was determined using a discounted cash flow approach as a measure of fair value. We recorded a full impairment charge on capitalized interest and other intangible assets as these costs were no longer probable to be recovered.

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 use a two-step process to test for impairment: We can also elect to proceed directly to the two-step process to test any reporting unit for impairment. This two-step process involves the following:

1. First, we compare the fair value of the reporting unit to its book value, including its goodwill. If fair value is less than book value, we consider our goodwill to be impaired.
2. Next, we measure the amount of the impairment by calculating the implied fair value of the reporting unit's goodwill. We do this by deducting the fair value of the tangible and intangible net assets of the reporting unit from the fair value we calculated in the first step. To the extent the goodwill's carrying value exceeds its implied fair value, we record an impairment charge.

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

If our assumptions change significantly, our requirement to record an impairment charge could also change.

At December 31, 2017, the estimated fair value of Great Lakes exceeded its carrying value by less than ten per cent. We measured the fair value of this reporting unit using a discounted cash flow analysis in our 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 reduction in Great Lakes' rates effective October 1, 2017 as a result of the expected outcome of 2017 Great Lakes Settlement. This reduction in rates was largely offset by expected cash flows from the long-term transportation contract with the Canadian Mainline, other opportunities to increase utilization on the system and the 2017 Great Lakes Settlement elimination of the revenue sharing mechanism with its customers. 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$379 million at December 31, 2017 (2016 – US$382 million).

As a result of information received during the process to monetize our U.S. Northeast power generation assets, 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 approach 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, 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. The impairment charge was recorded prior to Ravenswood's reclassification to assets held for sale.

Asset retirement obligations

When there is a legal obligation to set aside funds to cover future abandonment costs, and we can reasonably estimate them, we recognize the fair value of the ARO in our financial statements.

We cannot determine when we will retire many of our liquids pipelines, natural gas pipelines and transportation facilities, and regulated natural gas storage systems because we intend to operate them as long as there is supply and demand, and so we have not recorded obligations for them.

For those we do record, we use the following assumptions:

- when we expect to retire the asset
- the scope of abandonment and reclamation activities that are required
- inflation and discount rates.

The ARO is initially recorded when the obligation exists and is subsequently accreted through charges to operating expenses.

We continue to evaluate our future abandonment obligations and costs and monitor developments that could affect the amounts we record.

FINANCIAL INSTRUMENTS

Non-derivative financial instruments

Fair value of non-derivative financial instruments

The fair value of long-term debt and junior subordinated notes has been estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data service providers.

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

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 $)	2017	2016
Other current assets	**332**	376
Intangible and other assets	**73**	133
Accounts payable and other	**(387)**	(607)
Other long-term liabilities	**(72)**	(330)
	(54)	(428)

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, 2017 (millions of $)	Total fair value	2018	2019 and 2020	2021 and 2022
Derivative instruments held for trading				
Assets	389	320	64	5
Liabilities	(244)	(218)	(26)	—
Derivative instruments in hedging relationships				
Assets	16	12	—	4
Liabilities	(215)	(169)	(46)	—
	(54)	(55)	(8)	9

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

1 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell commodities are included net in revenues. Realized and unrealized gains and losses on interest rate and foreign exchange held for trading derivative instruments are included net in interest expense and interest income and other, respectively.

2 In 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 the consolidated statement of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests is as follows:

year ended December 31 (millions of $, pre-tax)	2017	2016
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Commodities	**(1)**	39
Interest rate	**4**	5
	3	44
Reclassification of (losses)/gains on derivative instruments from AOCI to net income (effective portion)[1]		
Commodities[2]	**(20)**	57
Interest rate[3]	**17**	14
	(3)	71

1 No amounts have been excluded from the assessment of hedge effectiveness. In 2017 and 2016, there were no gains or losses included in net income related to ineffective portions. Amounts in parentheses indicate losses recorded to OCI and AOCI.

2 Reported within revenues on the consolidated statement of income.

3 Reported within interest expense on the consolidated statement of income.

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, 2017, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $2 million (2016 – $19 million), with collateral provided in the normal course of business of nil (2016 – nil). If the credit-risk-related contingent features in these agreements were triggered on December 31, 2017, we would have been required to provide additional collateral of $2 million (2016 – $19 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 2017

Inventory

In July 2015, the Financial Accounting Standards Board (FASB) issued new guidance on simplifying the measurement of inventory. The new guidance specifies that an entity should measure inventory within the scope of this guidance at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This new guidance was effective January 1, 2017, was applied prospectively and did not have a material impact on our consolidated balance sheet.

Derivatives and hedging

In March 2016, the FASB issued new guidance that clarifies the requirements for assessing whether contingent call or put options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. The new guidance requires only an assessment of the four-step decision sequence outlined in GAAP to determine whether the economic characteristics and risks of call or put options are clearly and closely related to the economic characteristics and risks of their debt hosts. This new guidance was effective January 1, 2017, was applied prospectively and has not resulted in any impact on our consolidated financial statements.

Equity method investments

In March 2016, the FASB issued new guidance that simplifies the transition to equity method accounting. The new guidance eliminates the requirement to retroactively apply the equity method of accounting when an increase in ownership interest in an investment qualifies it for equity method accounting. This new guidance was effective January 1, 2017, was applied prospectively and has not resulted in any impact on our consolidated financial statements.

Employee share-based payments

In March 2016, the FASB issued new guidance that simplifies several aspects of the accounting for employee share-based payment transactions, including income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. The new guidance also permits entities to make an accounting policy election either to continue to estimate the total number of awards for which the requisite service period will not be rendered or to account for forfeitures when they occur. We have elected to account for forfeitures when they occur. This new guidance was effective January 1, 2017 and resulted in a cumulative-effect adjustment of $12 million to retained earnings and the recognition of a deferred tax asset related to employee share-based payments that were made prior to the adoption of this guidance.

Consolidation

In October 2016, the FASB issued new guidance on consolidation relating to VIEs held through related parties that are under common control. The new guidance amends the consolidation requirements such that if a decision maker is required to evaluate whether it is the primary beneficiary of a VIE, it will need to consider only its proportionate indirect interest in the VIE held through a common control party. The new guidance was effective January 1, 2017, was applied retrospectively and did not result in any change to our consolidation conclusions.

Future accounting changes

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 in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in an amount that reflects the total consideration to which it expects to be entitled during the term of the contract in exchange for those goods or services. The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue and the related cash flows. We will adopt the new guidance on the effective date of January 1, 2018. There are two methods in which the new guidance can be adopted: (1) a full retrospective approach with restatement of all prior periods presented, or (2) a modified retrospective approach with a cumulative-effect adjustment as of the date of adoption. We will adopt the guidance using the modified retrospective approach with the cumulative-effect of the adjustment, if any, recognized at the date of adoption, subject to allowable and elected practical expedients.

We identified all existing customer contracts that are within the scope of the new guidance by operating segment. We have completed our analysis of the contracts and have not identified any material differences in the amount and timing of revenue recognition as a result of implementing the new guidance. We will therefore, not require a cumulative-effect adjustment to opening retained earnings on January 1, 2018.

Although consolidated revenues will not be materially impacted by the new guidance, we will be required to add significant disclosures based on the prescribed requirements. These new disclosures will include information regarding the significant judgments used in evaluating when and how revenues, are recognized and information related to contract assets and deferred revenues. In addition, the new guidance requires that our revenue recognition policy disclosure includes additional detail regarding the various performance obligations and the nature, amount, timing and estimates of revenues and cash flows generated from contracts with customers. We have developed draft disclosures required in first quarter 2018 with a particular focus on the scope of contracts subject to disclosure of future revenues from remaining performance obligations. We have addressed system and process changes necessary to compile the information to meet the recognition and disclosure requirements of 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 will change 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 their other deferred tax assets. This new guidance is effective January 1, 2018 and a method of adoption is specified for each component of the guidance. We have completed our analysis and do not expect the adoption of this guidance to have a material impact on our consolidated financial statements.

Leases

In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease requiring the lessor 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 in order for an arrangement to qualify as a lease. 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. Leases will be classified as finance or operating, with classification affecting the pattern of expense recognition in the income statement. The new guidance does not make extensive changes to lessor accounting.

The new guidance is effective January 1, 2019, with early adoption permitted. A modified retrospective transition approach is required for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. We are continuing to identify and analyze existing lease agreements to determine the effect of application of the new guidance on our consolidated financial statements. We are also addressing system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance and continue to monitor and analyze additional guidance and clarification provided by the FASB.

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 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.

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 an intra-entity asset transfer when the transfer occurs. The new guidance is effective January 1, 2018 and will be applied using a modified retrospective approach. We have completed our analysis and do not expect the application of this guidance to have a material impact on our consolidated financial statements.

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 year and end of year total amounts on the statement of cash flows. This new guidance is effective January 1, 2018 and will be applied retrospectively.

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 and will be applied prospectively, however, early adoption is permitted.

Employee post-retirement benefits
In March 2017, the FASB issued new guidance that will require 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 is effective January 1, 2018. We have completed our analysis and do not expect the application of this guidance to have a material impact on our consolidated financial statements.

Amortization on purchased callable debt securities
In March 2017, the FASB issued new guidance that shortens the amortization period for the premium on certain purchased callable debt securities by requiring entities to amortize the premium to the earliest call date. This new guidance is effective January 1, 2019 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.

Hedge accounting
In August 2017, the FASB issued new guidance on hedge accounting, 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 additional disclosure requirements include cumulative basis adjustments for fair value hedges and the effect of hedging on individual statement of income line items. This new guidance is effective January 1, 2019, with early adoption permitted. We have elected to apply this guidance effective January 1, 2018. We have completed our analysis and do not expect the application of this guidance to have a material impact 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)	2017	2016	2015
Comparable EBITDA			
Canadian Natural Gas Pipelines	**2,144**	2,182	2,216
U.S. Natural Gas Pipelines	**2,357**	1,682	970
Mexico Natural Gas Pipelines	**519**	332	213
Liquids Pipelines	**1,348**	1,152	1,308
Energy	**1,030**	1,281	1,254
Corporate	**(21)**	18	(53)
Comparable EBITDA	**7,377**	6,647	5,908
Depreciation and amortization	**(2,048)**	(1,939)	(1,765)
Comparable EBIT	**5,329**	4,708	4,143
Specific items:			
Energy East impairment charge	**(1,256)**	—	—
Integration and acquisition related costs – Columbia	**(91)**	(179)	—
Keystone XL asset costs	**(34)**	(52)	—
Net gain/(loss) on U.S. Northeast power assets	**484**	(844)	—
Gain on sale of Ontario solar assets	**127**	—	—
Foreign exchange gain – inter-affiliate loan	**63**	—	—
Ravenswood goodwill impairment	**—**	(1,085)	—
Alberta PPA terminations and settlement	**—**	(332)	—
Restructuring costs	**—**	(22)	(99)
TC Offshore loss on sale	**—**	(4)	(125)
Keystone XL impairment charge	**—**	—	(3,686)
Turbine equipment impairment charge	**—**	—	(59)
Bruce Power merger – debt retirement charge	**—**	—	(36)
Risk management activities[1]	**62**	123	(37)
Segmented earnings	**4,684**	2,313	101

1

year ended December 31 (millions of $)	2017	2016	2015
Canadian Power	**11**	4	(8)
U.S. Power	**39**	113	(30)
Liquids marketing	**—**	(2)	—
Natural Gas Storage	**12**	8	1
Total unrealized gains/(losses) from risk management activities	**62**	123	(37)

QUARTERLY RESULTS

Selected quarterly consolidated financial data

(unaudited, millions of $, except per share amounts)

2017	Fourth	Third	Second	First
Revenues	**3,617**	**3,224**	**3,217**	**3,391**
Net income attributable to common shares	**861**	**612**	**881**	**643**
Comparable earnings	**719**	**614**	**659**	**698**
Comparable earnings per common share	**$0.82**	**$0.70**	**$0.76**	**$0.81**
Share statistics				
Net income per common share – basic and diluted	**$0.98**	**$0.70**	**$1.01**	**$0.74**
Dividends declared per common share	**$0.625**	**$0.625**	**$0.625**	**$0.625**

2016	Fourth	Third	Second	First
Revenues	3,635	3,642	2,756	2,514
Net (loss)/income attributable to common shares	(358)	(135)	365	252
Comparable earnings	626	622	366	494
Comparable earnings per common share	$0.75	$0.78	$0.52	$0.70
Share statistics				
Net (loss)/income per common share – basic and diluted	($0.43)	($0.17)	$0.52	$0.36
Dividends declared per common share	$0.565	$0.565	$0.565	$0.565

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:

- developments outside of the normal course of operations
- newly constructed assets being placed in service
- regulatory decisions.

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

- weather
- customer demand
- market prices for natural gas and power
- capacity prices and payments
- 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 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 business, which included an incremental after-tax loss of $7 million recorded on the sale of the thermal and wind package, $23 million of after-tax third-party insurance proceeds related to a 2017 Ravenswood outage and income tax adjustments
- 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 which were expensed pending further advancement of the project.

In third quarter 2017, comparable earnings excluded:

- an incremental net loss of $12 million related to the monetization of our U.S. Northeast power business which included an incremental loss of $7 million after tax on the sale of the thermal and wind package and $14 million of after-tax disposition costs and income tax adjustments
- 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 which were being expensed pending further advancement of the project.

In second quarter 2017, comparable earnings excluded:

- a $265 million net after-tax gain related to the monetization of our U.S. Northeast power business 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 which were being expensed pending further advancement of the project.

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 business
- a charge of $7 million after tax related to the maintenance of Keystone XL assets which were being expensed pending further advancement of the project
- a $7 million income tax recovery related to the realized loss on a third party sale of Keystone XL project assets. A provision for the expected pre-tax loss on these assets was included in our 2015 impairment charge, but the related income tax recoveries could not be recorded until realized.

In fourth quarter 2016, comparable earnings excluded:

- an $870 million after-tax charge related to the loss on U.S. Northeast power assets held for sale which included an $863 million after-tax loss on the thermal and wind package held for sale and $7 million of after-tax costs related to the monetization
- an additional $68 million after-tax loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the Alberta PPA terminations
- an after-tax charge of $67 million for costs associated with the acquisition of Columbia which included a $44 million deferred tax adjustment upon acquisition and $23 million of retention, severance and integration costs
- an after-tax charge of $18 million related to Keystone XL costs for the maintenance and liquidation of project assets which were being expensed pending further advancement of the project
- an after-tax restructuring charge of $6 million for additional expected future losses under lease commitments. These charges formed part of a restructuring initiative, which commenced in 2015, to maximize the effectiveness and efficiency of our existing operations and reduce overall costs.

In third quarter 2016, comparable earnings excluded:

- a $656 million after-tax impairment on the Ravenswood goodwill. 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
- costs associated with the acquisition of Columbia including a charge of $67 million after tax primarily relating to retention, severance and integration expenses
- $28 million of income tax recoveries related to the realized loss on a third party sale of Keystone XL plant and equipment. A provision for the expected loss on these assets was included in our fourth quarter 2015 impairment charge but the related tax recoveries could not be recorded until realized
- a charge of $9 million after tax related to Keystone XL costs for the maintenance and liquidation of project assets which were being expensed pending further advancement of the project
- a $3 million after-tax charge related to the monetization of our U.S. Northeast power business.

In second quarter 2016, comparable earnings excluded:

- a charge of $113 million related to costs associated with the acquisition of Columbia which included $109 million related to dividend equivalent payments on the subscription receipts
- a charge of $9 million after tax related to Keystone XL costs for the maintenance and liquidation of project assets which were being expensed pending further advancement of the project
- a charge of $10 million after tax for restructuring charges mainly related to expected future losses under lease commitments.

In first quarter 2016, comparable earnings excluded:

- a $176 million after-tax impairment charge on the carrying value of our Alberta PPAs as a result of our decision to terminate the PPAs
- a charge of $26 million related to costs associated with the acquisition of Columbia
- a charge of $6 million after tax related to Keystone XL costs for the maintenance and liquidation of project assets which were being expensed pending further advancement of the project
- an additional $3 million after-tax loss on the sale of TC Offshore which closed on March 31, 2016.

FOURTH QUARTER 2017 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	2017	2016
Canadian Natural Gas Pipelines	**333**	364
U.S. Natural Gas Pipelines	**461**	403
Mexico Natural Gas Pipelines	**93**	103
Liquids Pipelines	**(932)**	213
Energy	**472**	(574)
Corporate	**63**	(33)
Total segmented earnings	**490**	476
Interest expense	**(541)**	(542)
Allowance for funds used during construction	**140**	97
Interest income and other	**(9)**	(15)
Income before income taxes	**80**	16
Income tax recovery/(expense)	**870**	(274)
Net income/(loss)	**950**	(258)
Net income attributable to non-controlling interests	**(49)**	(68)
Net income/(loss) attributable to controlling interests	**901**	(326)
Preferred share dividends	**(40)**	(32)
Net income/(loss) attributable to common shares	**861**	(358)
Net income/(loss) per common share – basic and diluted	**$0.98**	($0.43)

Net income/(loss) attributable to common shares increased by $1,219 million or $1.41 per share for the three months ended December 31, 2017 compared to the same period in 2016 due to the changes in net income described below, as well as the dilutive effect of issuing 60 million common shares in the fourth quarter of 2016 and common shares issued under our DRP and corporate ATM program in 2017.

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 business, which included an incremental after-tax loss of $7 million recorded on the sale of the thermal and wind package, $23 million of after-tax third-party insurance proceeds related to a 2017 Ravenswood outage and income tax adjustments
- 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 which were expensed pending further advancement of the project.

Fourth quarter 2016 results included:

- an $870 million after-tax charge related to the loss on U.S. Northeast power assets held for sale which included an $863 million after-tax loss on the thermal and wind package held for sale and $7 million of after-tax costs related to the monetization
- an additional $68 million after-tax loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the Alberta PPA terminations
- an after-tax charge of $67 million for costs associated with the acquisition of Columbia which included a $44 million deferred tax adjustment upon closing of the acquisition and $23 million of retention, severance and integration costs
- an $18 million after-tax charge related to the maintenance and liquidation of Keystone XL assets which were expensed pending further advancement of the project
- an after-tax restructuring charge of $6 million for additional expected future losses under lease commitments. These charges form part of a restructuring initiative, which commenced in 2015, to maximize the effectiveness and efficiency of our existing operations and reduce overall costs.

Net income/(loss) 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/(loss) to comparable earnings

three months ended December 31 (millions of $, except per share amounts)	2017	2016
Net income/(loss) attributable to common shares	**861**	(358)
Specific items (net of tax):		
U.S. Tax Reform adjustment	**(804)**	—
Gain on sale of Ontario solar assets	**(136)**	—
Net (gain)/loss on sales of U.S. Northeast power assets	**(64)**	870
Energy East impairment charge	**954**	—
Keystone XL asset costs	**9**	18
Alberta PPA terminations and settlement	**—**	68
Acquisition related costs – Columbia	**—**	67
Restructuring costs	**—**	6
Risk management activities[1]	**(101)**	(45)
Comparable earnings	**719**	626
Net income/(loss) per common share	**$0.98**	($0.43)
Specific items (net of tax):		
U.S. Tax Reform adjustment	**(0.92)**	—
Gain on sale of Ontario solar assets	**(0.16)**	—
Net (gain)/loss on sales of U.S. Northeast power assets	**(0.08)**	1.05
Energy East impairment charge	**1.09**	—
Keystone XL asset costs	**0.01**	0.02
Alberta PPA terminations and settlement	**—**	0.08
Acquisition related costs – Columbia	**—**	0.08
Restructuring costs	**—**	0.01
Risk management activities	**(0.10)**	(0.06)
Comparable earnings per common share	**$0.82**	$0.75

1

three months ended December 31 (millions of $)	2017	2016
Canadian Power	**6**	1
U.S. Power	**136**	97
Liquids marketing	**15**	4
Natural Gas Storage	**7**	(1)
Foreign exchange	**(1)**	(23)
Income tax attributable to risk management activities	**(62)**	(33)
Total unrealized gains from risk management activities	**101**	45

Comparable earnings

Comparable earnings increased by $93 million or $0.07 per share for the three months ended December 31, 2017 compared to the same period in 2016 and was primarily the net effect of:

- 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 new intra-Alberta pipelines Grand Rapids and Northern Courier
- higher contribution from U.S. Natural Gas Pipelines due to lower operating costs including synergies achieved from the Columbia acquisition
- higher AFUDC on our rate-regulated U.S. natural gas pipelines, partially offset by our decision not to proceed with the Energy East Pipeline
- higher earnings from Bruce Power mainly due to higher volumes resulting from fewer outage days
- lower contribution from U.S. Power due to the monetization of our U.S. Northeast power generation assets in second quarter 2017 and the continued wind-down of our U.S. power marketing operations
- an after-tax impairment charge in 2017 of $16 million related to obsolete Energy equipment.

Highlights by business segment

Canadian Natural Gas Pipelines

Canadian Natural Gas Pipelines segmented earnings decreased by $31 million for the three months ended December 31, 2017 compared to the same period in 2016 and are equivalent to comparable EBIT.

Net income for the NGTL System increased by $6 million for the three months ended December 31, 2017 compared to the same period in 2016 mainly due to a higher average investment base, partially offset by lower OM&A incentive earnings.

Canadian Mainline's net income decreased by $4 million for the three months ended December 31, 2017 compared to the same period in 2016 primarily due to a lower average investment base and lower incentive earnings.

Depreciation and amortization increased by $16 million for the three months ended December 31, 2017 compared to the same period in 2016 mainly due to facilities that were placed in service for the NGTL System and Canadian Mainline.

U.S. Natural Gas Pipelines

U.S. Natural Gas Pipelines segmented earnings increased by $58 million for the three months ended December 31, 2017 compared to the same period in 2016. Segmented earnings for the three months ended December 31, 2016 included pre-tax costs of $11 million mainly related to retention and severance expenses resulting from the Columbia acquisition, which has been excluded from our calculation of comparable EBIT.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$45 million for the three months ended December 31, 2017 compared to the same period in 2016. This was primarily due to lower operating costs including synergies achieved from the Columbia acquisition.

Depreciation and amortization decreased by US$5 million for the three months ended December 31, 2017 compared to the same period in 2016 primarily due to fair value adjustments related to our Midstream assets recorded in fourth quarter 2016.

Mexico Natural Gas Pipelines

Mexico Natural Gas Pipelines segmented earnings decreased by $10 million for the three months ended December 31, 2017 compared to the same period in 2016 and are equivalent to comparable EBIT. Aside from the commercial factors outlined below, a weaker U.S. dollar had a negative impact on the Canadian dollar equivalent segmented earnings from our Mexico operations.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$5 million for the three months December 31, 2017 compared to the same period in 2016 and was the net effect of:

- incremental earnings from 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. The inter-affiliate loan interest is fully offset in interest income and other in the Corporate segment.

Depreciation and amortization increased by US$6 million for the three months ended December 31, 2017 compared to the same period in 2016 primarily due to the commencement of depreciation on Mazatlán.

Liquids Pipelines

Liquids Pipelines segmented earnings decreased by $1,145 million for the three months ended December 31, 2017 compared to the same period in 2016. This was primarily the net effect of a $1,256 million pre-tax impairment charge for the Energy East pipeline, $11 million (2016 – $15 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, and unrealized gains 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.

Comparable EBITDA for Liquids Pipelines increased by $99 million for the three months ended December 31, 2017 compared to the same period in 2016 and was the net effect of:

- higher uncontracted volumes on the Keystone Pipeline System
- new intra-Alberta pipelines, Grand Rapids and Northern Courier, which began operations in the second half of 2017
- a higher contribution from the liquids marketing business
- higher business development activities, including advancement of Keystone XL
- 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 increased by $3 million for the three months ended December 31, 2017 compared to the same period in 2016 as a result of the new facilities being placed in-service, partially offset by the effect of a weaker U.S. dollar.

Energy

Energy segmented earnings increased by $1,046 million for the three months ended December 31, 2017 compared to the same period in 2016 and included the following specific items:

- a gain in 2017 of $127 million before tax related to the sale of our Ontario solar assets
- a net gain in 2017 of $15 million before tax related to the monetization of our U.S. Northeast power assets which consisted primarily of insurance recoveries for a portion of repair costs incurred during an unplanned outage at Ravenswood prior to its sale
- in 2016, a loss of $839 million before tax related to the sale of the U.S. Northeast power assets which included an $829 million pre-tax loss on the thermal and wind package and $10 million of pre-tax disposition costs
- in 2016, a $92 million before tax loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the Alberta PPA terminations
- unrealized gains and losses in both years from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks.

The remainder of the Energy segmented earnings are equivalent to comparable EBIT along with comparable EBITDA.

Corporate

Corporate segmented earnings were $63 million for the three months ended December 31, 2017 compared to a loss of $33 million for the same period in 2016 and included the following specific items that have been excluded from comparable EBIT:

- in 2017, a foreign exchange gain 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
- in 2016, pre-tax integration and acquisition costs associated with the acquisition of Columbia and restructuring costs.

Comparable EBITDA decreased by $12 million for the three months ended December 31, 2017 compared to the same period in 2016 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
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
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
HSE	Health, safety and environment
investment base	Includes rate base as well as assets under construction
LDC	Local distribution company
LNG	Liquefied natural gas
MLP	Master limited partnership
OM&A	Operating, maintenance and administration
PPA	Power purchase arrangement
rate base	Our annual average investment used
TSA	Transportation Service Agreements
WCSB	Western Canada Sedimentary Basin

Accounting terms

AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive (loss)/income
ARO	Asset retirement obligations
DRP	Dividend reinvestment plan
GAAP	U.S. generally accepted accounting principles
FASB	Financial Accounting Standards Board (U.S.)
OCI	Other comprehensive (loss)/income
RRA	Rate-regulated accounting
ROE	Rate of return on common equity
Specific Item	Items we believe are significant but not reflective of our underlying operations in the period

Government and regulatory bodies terms

AER	Alberta Energy Regulator
CFE	Comisión Federal de Electricidad (Mexico)
CRE	Comisión Reguladora de Energia, or Energy Regulatory Commission (Mexico)
FERC	Federal Energy Regulatory Commission (U.S.)
IESO	Independent Electricity System Operator
ISO	Independent System Operator
NAFTA	North American Free Trade Agreement
NEB	National Energy Board (Canada)
OPEC	Organization of the Petroleum Exporting Countries
OPG	Ontario Power Generation
SEC	U.S. Securities and Exchange Commission
SGER	Specified Gas Emitters Regulations

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 2017 to that in 2016, and highlights significant changes between 2016 and 2015. 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 include 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, 2017, 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 14, 2018

Independent Auditors' Report of Registered Public Accounting Firm

To the Shareholders and the Board of Directors of TransCanada Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of TransCanada Corporation (the "Company") as of December 31, 2017, and 2016, 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, 2017, and the related notes (collectively referred to as the "financial statements").

In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017, and 2016, and its financial performance and its cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

Report on Internal Control over Financial Reporting

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, 2017, based on the criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 14, 2018 expressed an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's 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 and in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the 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 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.



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

Chartered Professional Accountants
Calgary, Canada
February 14, 2018

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 internal control over financial reporting as of December 31, 2017, based on the criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the criteria established in Internal Control – Integrated Framework (2013) issued by COSO.

Report on the Financial Statements

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets of the Company as of December 31, 2017 and 2016 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, 2017, and the related notes (collectively referred to as the "financial statements") and our report dated February 14, 2018 expressed an unqualified opinion on those 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 and in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada.

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 14, 2018

Consolidated statement of income

year ended December 31 (millions of Canadian $, except per share amounts)	2017	2016	2015
Revenues			
Canadian Natural Gas Pipelines	**3,693**	3,682	3,680
U.S. Natural Gas Pipelines	**3,584**	2,526	1,444
Mexico Natural Gas Pipelines	**570**	378	259
Liquids Pipelines	**2,009**	1,755	1,879
Energy	**3,593**	4,206	4,091
	13,449	12,547	11,353
Income from Equity Investments (Note 9)	**773**	514	440
Operating and Other Expenses			
Plant operating costs and other	**3,906**	3,861	3,303
Commodity purchases resold	**2,382**	2,172	2,237
Property taxes	**569**	555	517
Depreciation and amortization	**2,055**	1,939	1,765
Goodwill and other asset impairment charges (Notes 8, 11 and 12)	**1,257**	1,388	3,745
	10,169	9,915	11,567
Gain/(Loss) on Assets Held for Sale/Sold (Notes 6 and 26)	**631**	(833)	(125)
Financial Charges			
Interest expense (Note 17)	**2,069**	1,998	1,370
Allowance for funds used during construction	**(507)**	(419)	(295)
Interest income and other	**(184)**	(103)	132
	1,378	1,476	1,207
Income/(Loss) before Income Taxes	**3,306**	837	(1,106)
Income Tax (Recovery)/Expense (Note 16)			
Current	**149**	156	136
Deferred	**566**	196	(102)
Deferred – U.S. Tax Reform	**(804)**	—	—
	(89)	352	34
Net Income/(Loss)	**3,395**	485	(1,140)
Net income attributable to non-controlling interests (Note 19)	**238**	252	6
Net Income/(Loss) Attributable to Controlling Interests	**3,157**	233	(1,146)
Preferred share dividends	**160**	109	94
Net Income/(Loss) Attributable to Common Shares	**2,997**	124	(1,240)
Net Income/(Loss) per Common Share (Note 20)			
Basic	**$3.44**	$0.16	($1.75)
Diluted	**$3.43**	$0.16	($1.75)
Dividends Declared per Common Share	**$2.50**	$2.26	$2.08
Weighted Average Number of Common Shares (millions) (Note 20)			
Basic	**872**	759	709
Diluted	**874**	760	709

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 $)	2017	2016	2015
Net Income/(Loss)	**3,395**	485	(1,140)
Other Comprehensive (Loss)/Income, Net of Income Taxes			
Foreign currency translation losses and gains on net investment in foreign operations	**(749)**	3	813
Reclassification of foreign currency translation gains on net investment on disposal of foreign operations	**(77)**	—	—
Change in fair value of net investment hedges	**—**	(10)	(372)
Change in fair value of cash flow hedges	**3**	30	(57)
Reclassification to net income of gains and losses on cash flow hedges	**(2)**	42	88
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**(11)**	(26)	51
Reclassification of actuarial loss and prior service costs on pension and other post-retirement benefit plans	**16**	16	32
Other comprehensive (loss)/income on equity investments	**(106)**	(87)	47
Other comprehensive (loss)/income (Note 22)	**(926)**	(32)	602
Comprehensive Income/(Loss)	**2,469**	453	(538)
Comprehensive income attributable to non-controlling interests	**83**	241	312
Comprehensive Income/(Loss) Attributable to Controlling Interests	**2,386**	212	(850)
Preferred share dividends	**160**	109	94
Comprehensive Income/(Loss) Attributable to Common Shares	**2,226**	103	(944)

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 $)	2017	2016	2015
Cash Generated from Operations			
Net income/(loss)	**3,395**	485	(1,140)
Depreciation and amortization	**2,055**	1,939	1,765
Goodwill and other asset impairment charges (Notes 8, 11 and 12)	**1,257**	1,388	3,745
Deferred income taxes (Note 16)	**566**	196	(102)
Deferred income taxes – U.S. Tax Reform (Note 16)	**(804)**	—	—
Income from equity investments (Note 9)	**(773)**	(514)	(440)
Distributions received from operating activities of equity investments (Note 9)	**970**	844	793
Employee post-retirement benefits funding, net of expense (Note 23)	**(64)**	(3)	44
(Gain)/loss on assets held for sale/sold (Notes 6 and 26)	**(631)**	833	125
Equity allowance for funds used during construction	**(362)**	(253)	(165)
Unrealized (gains)/losses on financial instruments	**(149)**	(149)	58
Other	**43**	55	47
(Increase)/decrease in operating working capital (Note 25)	**(273)**	248	(346)
Net cash provided by operations	**5,230**	5,069	4,384
Investing Activities			
Capital expenditures (Note 4)	**(7,383)**	(5,007)	(3,918)
Capital projects in development (Note 4)	**(146)**	(295)	(511)
Contributions to equity investments (Notes 4 and 9)	**(1,681)**	(765)	(493)
Acquisitions, net of cash acquired	**—**	(13,608)	(236)
Proceeds from sale of assets, net of transaction costs	**5,317**	6	—
Other distributions from equity investments (Note 9)	**362**	727	9
Deferred amounts and other	**(168)**	159	270
Net cash used in investing activities	**(3,699)**	(18,783)	(4,879)
Financing Activities			
Notes payable issued/(repaid), net	**1,038**	(329)	(1,382)
Long-term debt issued, net of issue costs	**3,643**	12,333	5,045
Long-term debt repaid	**(7,085)**	(7,153)	(2,105)
Junior subordinated notes issued, net of issue costs	**3,468**	1,549	917
Dividends on common shares	**(1,339)**	(1,436)	(1,446)
Dividends on preferred shares	**(155)**	(100)	(92)
Distributions paid to non-controlling interests	**(283)**	(279)	(224)
Common shares issued, net of issue costs	**274**	7,747	27
Common shares repurchased (Note 20)	**—**	(14)	(294)
Preferred shares issued, net of issue costs	**—**	1,474	243
Partnership units of TC PipeLines, LP issued, net of issue costs	**225**	215	55
Common units of Columbia Pipeline Partners LP acquired	**(1,205)**	—	—
Net cash (used in)/provided by financing activities	**(1,419)**	14,007	744
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(39)**	(127)	112
Increase in Cash and Cash Equivalents	**73**	166	361
Cash and Cash Equivalents			
Beginning of year	**1,016**	850	489
Cash and Cash Equivalents			
End of year	**1,089**	1,016	850

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

Consolidated balance sheet

at December 31 (millions of Canadian $)		2017	2016
ASSETS			
Current Assets			
Cash and cash equivalents		**1,089**	1,016
Accounts receivable		**2,522**	2,075
Inventories		**378**	368
Assets held for sale		**—**	3,717
Other (Note 7)		**691**	908
		4,680	8,084
Plant, Property and Equipment (Note 8)		**57,277**	54,475
Equity Investments (Note 9)		**6,366**	6,544
Regulatory Assets (Note 10)		**1,376**	1,322
Goodwill (Note 11)		**13,084**	13,958
Loan Receivable from Affiliate (Note 9)		**919**	—
Intangible and Other Assets (Note 12)		**1,484**	3,026
Restricted Investments		**915**	642
		86,101	88,051
LIABILITIES			
Current Liabilities			
Notes payable (Note 13)		**1,763**	774
Accounts payable and other (Note 14)		**4,057**	3,861
Dividends payable		**586**	526
Accrued interest		**605**	595
Liabilities related to assets held for sale		**—**	86
Current portion of long-term debt (Note 17)		**2,866**	1,838
		9,877	7,680
Regulatory Liabilities (Note 10)		**4,321**	2,121
Other Long-Term Liabilities (Note 15)		**727**	1,183
Deferred Income Tax Liabilities (Note 16)		**5,403**	7,662
Long-Term Debt (Note 17)		**31,875**	38,312
Junior Subordinated Notes (Note 18)		**7,007**	3,931
		59,210	60,889
Common Units Subject to Rescission or Redemption (Note 19)		**—**	1,179
EQUITY			
Common shares, no par value (Note 20)		**21,167**	20,099
Issued and outstanding:	December 31, 2017 – 881 million shares December 31, 2016 – 864 million shares		
Preferred shares (Note 21)		**3,980**	3,980
Additional paid-in capital		**—**	—
Retained earnings		**1,623**	1,138
Accumulated other comprehensive loss (Note 22)		**(1,731)**	(960)
Controlling Interests		**25,039**	24,257
Non-controlling interests (Note 19)		**1,852**	1,726
		26,891	25,983
		86,101	88,051

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 $)	2017	2016	2015
Common Shares (Note 20)			
Balance at beginning of year	**20,099**	12,102	12,202
Shares issued:			
Under public offerings, net of issue costs	**—**	7,752	—
Under dividend reinvestment and share purchase plan	**790**	177	—
Under at-the-market equity issuance program, net of issue costs	**216**	—	—
On exercise of stock options	**62**	74	30
Shares repurchased	**—**	(6)	(130)
Balance at end of year	**21,167**	20,099	12,102
Preferred Shares			
Balance at beginning of year	**3,980**	2,499	2,255
Shares issued under public offerings, net of issue costs	**—**	1,481	244
Balance at end of year	**3,980**	3,980	2,499
Additional Paid-In Capital			
Balance at beginning of year	**—**	7	370
Issuance of stock options, net of exercises	**6**	6	8
Dilution from TC PipeLines, LP units issued	**26**	24	6
Common shares repurchased (Note 20)	**—**	(8)	(164)
Asset drop downs to TC PipeLines, LP	**(202)**	(38)	(213)
Columbia Pipeline Partners LP acquisition	**(171)**	—	—
Reclassification of additional paid-in capital deficit to retained earnings	**341**	9	—
Balance at end of year	**—**	—	7
Retained Earnings			
Balance at beginning of year	**1,138**	2,769	5,478
Net income/(loss) attributable to controlling interests	**3,157**	233	(1,146)
Common share dividends	**(2,184)**	(1,733)	(1,471)
Preferred share dividends	**(159)**	(122)	(92)
Adjustment related to employee share-based payments (Note 3)	**12**	—	—
Reclassification of additional paid-in capital deficit to retained earnings	**(341)**	(9)	—
Balance at end of year	**1,623**	1,138	2,769
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(960)**	(939)	(1,235)
Other comprehensive (loss)/income attributable to controlling interests (Note 22)	**(771)**	(21)	296
Balance at end of year	**(1,731)**	(960)	(939)
Equity Attributable to Controlling Interests	**25,039**	24,257	16,438
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,726**	1,717	1,583
Acquisition of non-controlling interests in Columbia Pipeline Partners LP	**—**	1,051	—
Net income attributable to non-controlling interests	**238**	252	6
Other comprehensive (loss)/income attributable to non-controlling interests	**(155)**	(11)	306
Issuance of TC PipeLines, LP units			
Proceeds, net of issue costs	**225**	215	55
Decrease in TransCanada's ownership of TC PipeLines, LP	**(41)**	(40)	(11)
Reclassification from/(to) common units subject to rescission or redemption (Note 19)	**106**	(1,179)	—
Distributions declared to non-controlling interests	**(280)**	(279)	(222)
Impact of Columbia Pipeline Partners LP acquisition	**33**	—	—
Balance at end of year	**1,852**	1,726	1,717
Total Equity	**26,891**	25,983	18,155

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 which is non-operational, consisting of corporate and administrative functions.

Canadian Natural Gas Pipelines

The Canadian Natural Gas Pipelines segment consists of the Company's investments in 40,429 km (25,121 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 49,779 km (30,931 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 1,680 km (1,044 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 11 power generation facilities and 118 Bcf of non-regulated natural gas storage facilities. These include assets in Alberta, Ontario, Québec, New Brunswick and Arizona.

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. Significant estimates and judgments used in the preparation of the consolidated financial statements include, but are not limited to:

- fair value of assets and liabilities acquired in a business combination (Note 5)
- fair value and depreciation rates of plant, property and equipment (Note 8)
- carrying value of regulatory assets and liabilities (Note 10)
- fair value of goodwill (Note 11)
- fair value of intangible assets (Note 12)
- 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
- provision 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) or the Alberta Energy Regulator (AER). 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. 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 liquids pipelines as the regulators' decisions regarding operations and tolls on those systems generally do not have an impact on timing of recognition of revenues and expenses.

Revenue Recognition

Natural Gas Pipelines and Liquids Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's natural gas and liquids pipelines are generated from contractual arrangements for committed capacity and from the transportation of natural gas or crude oil. Revenues earned from firm contracted capacity arrangements are recognized ratably over the contract period regardless of the amount of natural gas or crude oil that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when physical deliveries of natural gas or crude oil are made.

Revenues from Canadian natural gas pipelines subject to RRA are recognized in accordance with decisions made by the NEB. The Company's Canadian natural gas pipeline tolls are based on revenue requirements designed to recover the costs of providing natural gas transportation services, which include a return of and return on capital, as approved by the NEB. The Company's Canadian natural gas pipelines generally are 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 rates. The Company's Canadian natural gas pipelines, at times, are subject to incentive mechanisms, as negotiated with shippers and approved by the NEB. These mechanisms can result in the Company recognizing more or less revenue than required to recover the costs that are subject to incentives. Revenues on firm contracted capacity are recognized ratably over the contract period. Revenues from interruptible or volumetric-based services are recorded when physical delivery is made. Revenues recognized prior to an NEB decision on rates for that period reflect the NEB's last approved rate of return on common equity (ROE) assumptions. Adjustments to revenues are recorded when the NEB decision is received.

The Company's U.S. natural gas pipelines are subject to FERC regulations and, as a result, revenues collected may be subject to refund during a rate proceeding. 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.

Revenues from the Company's Mexico natural gas pipelines are primarily collected based on CRE-approved negotiated firm capacity contracts and recognized ratably over the contract period. Other volumes shipped on these pipelines are subject to CRE-approved tariffs.

The Company does not take ownership of the natural gas that it transports for its customers.

Regulated Natural Gas Storage

Revenues from the Company's regulated natural gas storage services are recognized either ratably over the contract period for firm committed capacity regardless of the amount of natural gas that is stored, or when gas is injected or withdrawn for interruptible or volumetric-based services. The Company does not take ownership of the natural gas that it stores for its customers.

Midstream and Other

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 contract period regardless of the amount of natural gas that is subject to these services. The Company also owns mineral rights associated with certain storage facilities. These mineral rights can be leased or contributed to producers of natural gas in return for a royalty interest. Royalties from mineral interests are recognized when commodities are produced.

Energy

Power Generation

Revenues from the Company's Energy business are primarily derived from the sale of electricity, which is recorded at the time of delivery. Revenues also include capacity payments and ancillary services, as well as gains and losses resulting from the use of commodity derivative contracts. The accounting for derivative contracts is described in the Derivative instruments and hedging activities policy in this note.

Non-Regulated Natural Gas Storage

Revenues earned from providing non-regulated natural gas storage services are recognized in accordance with the terms of the natural gas storage contracts, which is generally over the term of the contract. Revenues earned on the sale of proprietary natural gas are recorded net of the cost of the proprietary natural gas in the month of delivery. Derivative contracts for the purchase or sale of natural gas are recorded at fair value with changes in fair value recorded in Revenues.

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 natural gas inventory in storage, crude oil in transit, materials and supplies including spare parts and fuel. 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. Depreciation expense is no longer recorded once an asset is classified as held for sale.

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 six 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 a 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. When the asset is ready for its intended use and available for operations, capitalized project costs are depreciated in accordance with the Company's plant, property and equipment depreciation policies.

Impairment of Long-Lived Assets

The Company reviews long-lived assets, such as Plant, property and equipment and Intangible assets 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 or the estimated selling price 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. 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 first step of a two-step impairment test is performed by comparing the fair value of the reporting unit to its carrying value, which includes goodwill. If the fair value of the reporting unit is less than its carrying value, an impairment is indicated and the second step is performed to measure the amount of the impairment. In the second step, the implied fair value of goodwill is calculated by deducting the recognized amounts of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of goodwill exceeds the calculated implied fair value of goodwill, an impairment charge is recorded in an amount equal to the difference. The Company can elect to move directly to the first step of the two-step impairment test for any of its reporting units when performing its annual impairment test.

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 were subleased to third parties under terms and conditions similar to the PPAs, and were 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 during 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.

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. 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. These estimates 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. 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/(loss) (OCI) in the year in which the change occurs. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized out of Accumulated other comprehensive income/(loss) (AOCI) and into net income over the 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 effective portion of the change in the fair value of the hedging derivative is initially recognized in OCI, while any ineffective portion is recognized in net income in the same financial statement category as the underlying transaction. 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 effective portion of foreign exchange gains and losses on the hedging instruments is recognized in OCI and the ineffective portion is recognized in net income. 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 the 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 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, Plant, property and equipment, or a charge to net income, 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 2017

Inventory

In July 2015, the Financial Accounting Standards Board (FASB) issued new guidance on simplifying the measurement of inventory. The new guidance specifies that an entity should measure inventory within the scope of this guidance at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This new guidance was effective January 1, 2017, was applied prospectively and did not have a material impact on the Company's Consolidated balance sheet.

Derivatives and hedging

In March 2016, the FASB issued new guidance that clarifies the requirements for assessing whether contingent call or put options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. The new guidance requires only an assessment of the four-step decision sequence outlined in GAAP to determine whether the economic characteristics and risks of call or put options are clearly and closely related to the economic characteristics and risks of their debt hosts. This new guidance was effective January 1, 2017, was applied prospectively and has not resulted in any impact on the Company's consolidated financial statements.

Equity method investments

In March 2016, the FASB issued new guidance that simplifies the transition to equity method accounting. The new guidance eliminates the requirement to retroactively apply the equity method of accounting when an increase in ownership interest in an investment qualifies it for equity method accounting. This new guidance was effective January 1, 2017, was applied prospectively and has not resulted in any impact on the Company's consolidated financial statements.

Employee share-based payments

In March 2016, the FASB issued new guidance that simplifies several aspects of the accounting for employee share-based payment transactions, including income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. The new guidance also permits entities to make an accounting policy election either to continue to estimate the total number of awards for which the requisite service period will not be rendered or to account for forfeitures when they occur. The Company has elected to account for forfeitures when they occur. This new guidance was effective January 1, 2017 and resulted in a cumulative-effect adjustment of $12 million to retained earnings and the recognition of a deferred tax asset related to employee share-based payments that were made prior to the adoption of this guidance.

Consolidation

In October 2016, the FASB issued new guidance on consolidation relating to VIEs held through related parties that are under common control. The new guidance amends the consolidation requirements such that if a decision maker is required to evaluate whether it is the primary beneficiary of a VIE, it will need to consider only its proportionate indirect interest in the VIE held through a common control party. The new guidance was effective January 1, 2017, was applied retrospectively and did not result in any change to the Company's consolidation conclusions.

Future Accounting Changes

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 in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in an amount that reflects the total consideration to which it expects to be entitled during the term of the contract in exchange for those goods or services. The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue and the related cash flows. The Company will adopt the new guidance on the effective date of January 1, 2018. There are two methods in which the new guidance can be adopted: (1) a full retrospective approach with restatement of all prior periods presented, or (2) a modified retrospective approach with a cumulative-effect adjustment as of the date of adoption. The Company will adopt the guidance using the modified retrospective approach with the cumulative-effect of the adjustment, if any, recognized at the date of adoption, subject to allowable and elected practical expedients.

The Company identified all existing customer contracts that are within the scope of the new guidance by operating segment. The Company has completed its analysis of the contracts and has not identified any material differences in the amount and timing of revenue recognition as a result of implementing the new guidance. Therefore, the Company will not require a cumulative-effect adjustment to opening retained earnings on January 1, 2018.

Although consolidated revenues will not be materially impacted by the new guidance, the Company will be required to add significant disclosures based on the prescribed requirements. These new disclosures will include information regarding the significant judgments used in evaluating when and how revenues, are recognized and information related to contract assets and deferred revenues. In addition, the new guidance requires that the Company's revenue recognition policy disclosure include additional detail regarding the various performance obligations and the nature, amount, timing and estimates of revenues and cash flows generated from contracts with customers. The Company has developed draft disclosures required in first quarter 2018 with a particular focus on the scope of contracts subject to disclosure of future revenues from remaining performance obligations. The Company has addressed system and process changes necessary to compile the information to meet the recognition and disclosure requirements of 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 will change 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 is effective January 1, 2018 and a method of adoption is specified for each component of the guidance. The Company has completed its analysis and does not expect the adoption of this guidance to have a material impact on its consolidated financial statements.

Leases

In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease requiring the lessor 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 in order for an arrangement to qualify as a lease. 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. Leases will be classified as finance or operating, with classification affecting the pattern of expense recognition in the income statement. The new guidance does not make extensive changes to lessor accounting.

The new guidance is effective January 1, 2019, with early adoption permitted. A modified retrospective transition approach is required for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. The Company is continuing to identify and analyze existing lease agreements to determine the effect of application of the new guidance on its consolidated financial statements. The Company is also addressing system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance and continues to monitor and analyze additional guidance and clarification provided by the FASB.

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 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.

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 an intra-entity asset transfer when the transfer occurs. The new guidance is effective January 1, 2018 and will be applied using a modified retrospective approach. The Company has completed its analysis and does not expect the application of this guidance to have a material impact on its consolidated financial statements.

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 year and end of year total amounts on the statement of cash flows. This new guidance is effective January 1, 2018 and will be applied retrospectively.

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 and will be applied prospectively, however, early adoption is permitted.

Employee post-retirement benefits
In March 2017, the FASB issued new guidance that will require 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 is effective January 1, 2018. The Company has completed its analysis and does not expect the application of this guidance to have a material impact on its consolidated financial statements.

Amortization on purchased callable debt securities
In March 2017, the FASB issued new guidance that shortens the amortization period for the premium on certain purchased callable debt securities by requiring entities to amortize the premium to the earliest call date. This new guidance is effective January 1, 2019 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.

Hedge accounting
In August 2017, the FASB issued new guidance on hedge accounting, 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 additional disclosure requirements include cumulative basis adjustments for fair value hedges and the effect of hedging on individual statement of income line items. This new guidance is effective January 1, 2019, with early adoption permitted. The Company has elected to apply this guidance effective January 1, 2018. The Company has completed its analysis and does not expect the application of this guidance to have a material impact on its consolidated financial statements.

4. SEGMENTED 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)	—
	3,693	3,635	570	2,009	3,593	(51)	13,449
Income from equity investments	11	240	(9)	(3)	471	63 [2]	773
Plant operating costs and other	(1,300)	(1,340)	(42)	(623)	(550)	(51)	(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 assets held for sale/sold	—	—	—	—	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							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 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as revenues in the segment providing the service, as expenses in the segment receiving the service and are eliminated on consolidation within the Corporate segment. Intersegment profit is recognized when the product or service has been provided to third parties.

2 This Income from equity investments relates to foreign exchange gains on the Company's inter-affiliate loan with Sur de Texas. The peso-denominated loan to the Sur de Texas joint venture represents the Company's proportionate share of 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)	—
	3,682	2,582	378	1,755	4,206	(56)	12,547
Income from equity investments	12	214	(3)	(1)	292	—	514
Plant operating costs and other	(1,245)	(1,057)	(43)	(568)	(884)	(64)	(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 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as revenues in the segment providing the service, as expenses in the segment receiving the service and are eliminated on consolidation within the Corporate segment. Intersegment profit is recognized when the product or service has been provided to third parties.

year ended December 31, 2015 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate[1]	Total
Revenues	3,680	1,444	259	1,879	4,091	—	11,353
Intersegment revenues	—	47	—	—	—	(47)	—
	3,680	1,491	259	1,879	4,091	(47)	11,353
Income from equity investments	12	162	5	—	261	—	440
Plant operating costs and other	(1,204)	(606)	(51)	(492)	(845)	(105)	(3,303)
Commodity purchases resold	—	—	—	—	(2,237)	—	(2,237)
Property taxes	(272)	(77)	—	(79)	(89)	—	(517)
Depreciation and amortization	(849)	(248)	(44)	(283)	(341)	—	(1,765)
Asset impairment charges	—	—	—	(3,686)	(59)	—	(3,745)
Loss on assets held for sale/sold	—	(125)	—	—	—	—	(125)
Segmented earnings/(losses)	1,367	597	169	(2,661)	781	(152)	101
Interest expense							(1,370)
Allowance for funds used during construction							295
Interest income and other							(132)
Loss before income taxes							(1,106)
Income tax expense							(34)
Net loss							(1,140)
Net income attributable to non-controlling interests							(6)
Net loss attributable to controlling interests							(1,146)
Preferred share dividends							(94)
Net loss attributable to common shares							(1,240)
Capital spending							
Capital expenditures	1,366	534	566	1,012	376	64	3,918
Capital projects in development	230	3	—	278	—	—	511
Contributions to equity investments	—	—	—	311	182	—	493
	1,596	537	566	1,601	558	64	4,922

1 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as revenues in the segment providing the service, as expenses in the segment receiving the service and are eliminated on consolidation within the Corporate segment. Intersegment profit is recognized when the product or service has been provided to third parties.

at December 31 (millions of Canadian $)	2017	2016
Total Assets		
Canadian Natural Gas Pipelines	**16,904**	15,816
U.S. Natural Gas Pipelines	**35,898**	34,422
Mexico Natural Gas Pipelines	**5,716**	5,013
Liquids Pipelines	**15,438**	16,896
Energy	**8,503**	13,169
Corporate	**3,642**	2,735
	86,101	88,051

Geographic Information

year ended December 31 (millions of Canadian $)	2017	2016	2015
Revenues			
Canada – domestic	**3,618**	3,697	3,930
Canada – export	**1,255**	1,177	1,292
United States	**8,006**	7,295	5,872
Mexico	**570**	378	259
	13,449	12,547	11,353

at December 31 (millions of Canadian $)	2017	2016
Plant, Property and Equipment		
Canada	**21,632**	20,531
United States	**30,693**	29,414
Mexico	**4,952**	4,530
	57,277	54,475

5. ACQUISITION OF COLUMBIA

On July 1, 2016, TransCanada acquired 100 per cent ownership of Columbia Pipeline Group, Inc. (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 17, Long-term debt and Note 20, Common shares for further information on the acquisition bridge facilities and the subscription receipts, respectively.

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.

	July 1, 2016	
(millions of $)	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 (Note 11)	**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). This adjustment did not impact the Company's net income. At December 31, 2017, goodwill related to the acquisition of Columbia is US$7,802 million (2016 – US$7,747 million). Refer to Note 11, Goodwill, for further information.

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 U.S. effective tax rate of 39 per cent.

The fair value of Columbia's non-controlling interest was based on the approximately53.8 million Columbia Pipeline Partners LP (CPPL) common units outstanding to the public as of June 30, 2016, and valued at theJune 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)

6. ASSETS HELD FOR SALE

U.S. Northeast Power Assets

The Company's monetization of its U.S. Northeast power assets, for the purpose of permanently financing the Columbia acquisition, included the sales of TC Hydro, Ravenswood, Ironwood, Kibby Wind and Ocean State Power that closed in second quarter 2017.

On November 1, 2016, the Company entered into an agreement to sell TC Hydro to a third party. At December 31, 2016, the related assets and liabilities were classified as held for sale in the Energy segment. On April 19, 2017, the Company completed the sale of TC Hydro for proceeds of approximately US$1.07 billion, before post-closing adjustments. Refer to Note 26, Other acquisitions and dispositions, for further information.

On November 1, 2016, the Company entered into an agreement to sell Ravenswood, Ironwood, Kibby Wind and Ocean State Power to a third party. As a result, the Company recorded a loss of approximately $829 million ($863 million after tax) in 2016 which was included in Gain/(loss) on assets held for sale/sold in the Consolidated statement of income. This included the impact of an estimated $70 million of foreign currency translation gains to be reclassified from AOCI to net income on close. At December 31, 2016, the related assets and liabilities were classified as held for sale in the Energy segment and were recorded at their fair values less costs to sell based on the proceeds expected from the sale. On June 2, 2017, TransCanada completed the sale of these assets for proceeds of approximately US$2.029 billion, before post-closing adjustments. Refer to Note 26, Other acquisitions and dispositions, for further information.

7. OTHER CURRENT ASSETS

at December 31 (millions of Canadian $)	2017	2016
Fair value of derivative contracts (Note 24)	**332**	376
Prepaid expenses	**109**	131
Cash provided as collateral	**99**	313
Regulatory assets (Note 10)	**23**	33
Other	**128**	55
	691	908

8. PLANT, PROPERTY AND EQUIPMENT

at December 31 (millions of Canadian $)	2017 Cost	2017 Accumulated Depreciation	2017 Net Book Value	2016 Cost	2016 Accumulated Depreciation	2016 Net Book Value
Canadian Natural Gas Pipelines						
NGTL System						
Pipeline	**10,153**	**4,190**	**5,963**	8,814	3,951	4,863
Compression	**3,021**	**1,593**	**1,428**	2,447	1,499	948
Metering and other	**1,188**	**569**	**619**	1,124	519	605
	14,362	**6,352**	**8,010**	12,385	5,969	6,416
Under construction	**940**	**—**	**940**	1,151	—	1,151
	15,302	**6,352**	**8,950**	13,536	5,969	7,567
Canadian Mainline						
Pipeline	**9,763**	**6,455**	**3,308**	9,502	6,221	3,281
Compression	**3,605**	**2,499**	**1,106**	3,537	2,361	1,176
Metering and other	**655**	**207**	**448**	605	198	407
	14,023	**9,161**	**4,862**	13,644	8,780	4,864
Under construction	**156**	**—**	**156**	219	—	219
	14,179	**9,161**	**5,018**	13,863	8,780	5,083
Other Canadian Natural Gas Pipelines						
Other[1]	**1,815**	**1,363**	**452**	1,728	1,273	455
Under construction	**4**	**—**	**4**	112	—	112
	1,819	**1,363**	**456**	1,840	1,273	567
	31,300	**16,876**	**14,424**	29,239	16,022	13,217
U.S. Natural Gas Pipelines						
Columbia Gas						
Pipeline	**3,550**	**125**	**3,425**	3,317	42	3,275
Compression	**1,547**	**64**	**1,483**	1,636	29	1,607
Metering and other	**2,306**	**37**	**2,269**	2,550	8	2,542
	7,403	**226**	**7,177**	7,503	79	7,424
Under construction	**3,332**	**—**	**3,332**	1,127	—	1,127
	10,735	**226**	**10,509**	8,630	79	8,551
ANR						
Pipeline	**1,427**	**365**	**1,062**	1,468	349	1,119
Compression	**1,582**	**286**	**1,296**	1,494	260	1,234
Metering and other	**961**	**268**	**693**	988	254	734
	3,970	**919**	**3,051**	3,950	863	3,087
Under construction	**358**	**—**	**358**	232	—	232
	4,328	**919**	**3,409**	4,182	863	3,319

at December 31 (millions of Canadian $)	2017 Cost	2017 Accumulated Depreciation	2017 Net Book Value	2016 Cost	2016 Accumulated Depreciation	2016 Net Book Value
Other U.S. Natural Gas Pipelines						
GTN	**2,107**	**822**	**1,285**	2,221	810	1,411
Great Lakes	**1,988**	**1,113**	**875**	2,106	1,155	951
Columbia Gulf	**1,115**	**37**	**1,078**	880	5	875
Midstream	**1,085**	**54**	**1,031**	1,072	23	1,049
Other[2]	**1,950**	**574**	**1,376**	2,120	567	1,553
	8,245	**2,600**	**5,645**	8,399	2,560	5,839
Under construction	**699**	**—**	**699**	346	—	346
	8,944	**2,600**	**6,344**	8,745	2,560	6,185
	24,007	**3,745**	**20,262**	21,557	3,502	18,055
Mexico Natural Gas Pipelines						
Pipeline	**2,486**	**214**	**2,272**	2,734	180	2,554
Compression	**388**	**30**	**358**	422	19	403
Metering and other	**522**	**65**	**457**	502	40	462
	3,396	**309**	**3,087**	3,658	239	3,419
Under construction	**1,865**	**—**	**1,865**	1,108	—	1,108
	5,261	**309**	**4,952**	4,766	239	4,527
Liquids Pipelines						
Keystone Pipeline System						
Pipeline	**9,002**	**992**	**8,010**	10,572	901	9,671
Pumping equipment	**1,022**	**152**	**870**	928	121	807
Tanks and other	**3,314**	**385**	**2,929**	2,521	286	2,235
	13,338	**1,529**	**11,809**	14,021	1,308	12,713
Under construction	**456**	**—**	**456**	479	—	479
	13,794	**1,529**	**12,265**	14,500	1,308	13,192
Intra-Alberta Pipelines[3]						
Pipeline	**748**	**3**	**745**	—	—	—
Pumping equipment	**104**	**—**	**104**	—	—	—
Tanks and other	**259**	**1**	**258**	—	—	—
	1,111	**4**	**1,107**	—	—	—
Under construction	**47**	**—**	**47**	955	—	955
	1,158	**4**	**1,154**	955	—	955
	14,952	**1,533**	**13,419**	15,455	1,308	14,147
Energy						
Natural Gas[4,5]	**2,645**	**743**	**1,902**	2,696	696	2,000
Wind and Solar[6]	**673**	**204**	**469**	1,180	245	935
Natural Gas Storage and Other	**734**	**156**	**578**	731	146	585
	4,052	**1,103**	**2,949**	4,607	1,087	3,520
Under construction	**1,028**	**—**	**1,028**	729	—	729
	5,080	**1,103**	**3,977**	5,336	1,087	4,249
Corporate	**411**	**168**	**243**	410	130	280
	81,011	**23,734**	**57,277**	76,763	22,288	54,475

1 Includes Foothills, Ventures LP and Great Lakes Canada .
2 Includes Bison, Portland Natural Gas Transmission System, North Baja, Tuscarora and Crossroads.
3 Includes Northern Courier, placed in-service on November 1, 2017 and White Spruce.

4 Includes facilities with long-term PPAs that are accounted for as operating leases. The cost and accumulated depreciation of these facilities was $ 1,264 million and $354 million, respectively, at December 31, 2017 (2016 – $1,319 million and $335 million, respectively). Revenues of $ 215 million were recognized in 2017 (2016 – $212 million; 2015 – $235 million) through the sale of electricity under the related PPAs.

5 Includes Coolidge, Grandview, and Bécancour assets which operate under operating leases, along with Halton Hills and Alberta cogeneration natural gas-fired facilities.

6 Ontario solar assets are excluded from the Wind and Solar net book value at December 31, 2017 as they were sold on December 19, 2017. Refer to Note 26, Other acquisitions and dispositions, for further information.

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

Following the evaluation of specific capital project opportunities in 2015, it was determined that the carrying value of certain Energy turbine equipment was not fully recoverable. These turbines had been previously purchased for a power development project that did not proceed. As a result, at December 31, 2015, the Company recognized a non-cash impairment charge of
$59 million ($43 million after tax) in the Energy segment. The non-cash charge was recorded in Goodwill and other asset impairment charges on the Consolidated statement of income. This impairment charge was based on the excess of the carrying value over the estimated fair value of the turbines, which was determined based on a comparison to similar assets available for sale in the market.

At December 31, 2017, the Company again re-assessed the remaining carrying value of this Energy turbine equipment and determined that it was not recoverable. As a result, 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. The non-cash charge was recorded in Goodwill and other asset impairment charges on the Consolidated statement of income.

Keystone XL Impairment

At December 31, 2015, the Company evaluated its investment in Keystone XL and related projects for impairment in connection with the November 6, 2015 denial of the U.S. Presidential permit. As a result of the analysis, the Company recognized a non-cash impairment charge in its Liquids Pipelines segment of $3,686 million ($2,891 million after tax) based on the excess of the carrying value over the estimated fair value of$621 million of these assets. 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, 2017	Income/(Loss) from Equity Investments year ended December 31 2017	2016	2015	Equity Investments at December 31 2017	2016
Canadian Natural Gas Pipelines						
TQM	50.0%	**11**	12	12	**68**	71
U.S. Natural Gas Pipelines						
Northern Border[1]	50.0%	**87**	92	85	**641**	597
Iroquois[2]	50.0%	**59**	54	51	**280**	309
Millennium[3]	47.5%	**66**	33	—	**291**	295
Pennant Midstream[3]	47.0%	**11**	6	—	**228**	246
Other	Various	**17**	29	26	**92**	93
Mexico Natural Gas Pipelines						
Sur de Texas[4]	60.0%	**66**	(3)	—	**399**	255
TransGas	46.5%	**(12)**	—	5	**—**	28
Liquids Pipelines						
Grand Rapids[5]	50.0%	**17**	(1)	—	**996**	876
Other[6]	Various	**(20)**	—	—	**20**	39
Energy						
Bruce Power[7]	48.4%	**434**	293	249	**2,987**	3,356
Portlands Energy[8]	50.0%	**31**	33	30	**301**	313
ASTC Power Partnership	50.0%	**—**	(37)	(23)	**—**	—
Other	Various	**6**	3	5	**63**	66
		773	514	440	**6,366**	6,544

1 At December 31, 2017, 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 (2016 – US$116 million) due to the fair value assessment of assets at the time of acquisition.

2 At December 31, 2017, the difference between the carrying value of the investment and the underlying equity in the net assets of Iroquois was US$41 million (2016 – US$48 million) due mainly to the fair value assessment of the assets at the time of acquisition.

3 Acquired as part of 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 amounts recorded in the Corporate segment.

5 Grand Rapids was placed in service in August 2017. At December 31, 2017, the difference between the carrying value of the investment and the underlying equity in the net assets of Grand Rapids was $105 million (2016 – $86 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, 2017, the Canaport Energy East Marine Terminal Limited Partnership investment was nil.

7 At December 31, 2017, the difference between the carrying value of the investment and the underlying equity in the net assets of Bruce Power was $902 million (2016 – $942 million) due to the fair value assessment of assets at the time of acquisitions.

8 At December 31, 2017, the difference between the carrying value of the investment and the underlying equity in the net assets of Portlands Energy was $73 million (2016 – $70 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 impairment charge represents the write-down of the remaining carrying value of the equity investment. The non-cash impairment charge 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 its Liquids Pipelines segment Income from equity investments 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, 2017 were $1,332 million (2016 – $1,571 million; 2015 – $802 million) of which $362 million (2016 – $727 million; 2015 – $9 million) was included in Investing activities in the Consolidated statement of cash flows with respect to distributions received from Bruce Power in 2017 and 2016 from its financing program. Undistributed earnings from equity investments were $198 million at December 31, 2015.

Contributions made to equity investments for the year ended December 31, 2017 were $1,681 million (2016 – $765 million; 2015 – $493 million) and are included in Investing activities in the Consolidated statement of cash flows. For 2017, contributions include $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 $)	2017	2016	2015
Income			
Revenues	**4,913**	4,336	4,337
Operating and other expenses	**(2,993)**	(3,068)	(3,142)
Net income	**1,636**	1,080	1,046
Net income attributable to TransCanada	**773**	514	440

at December 31 (millions of Canadian $)	2017	2016
Balance Sheet		
Current assets	**2,176**	1,669
Non-current assets	**17,869**	15,853
Current liabilities	**(1,577)**	(1,120)
Non-current liabilities	**(8,217)**	(5,867)

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. On April 21, 2017, TransCanada entered into a MXN$13.6 billion unsecured revolving credit facility with the joint venture, which bears interest at a floating rate and matures in March 2022. On December 6, 2017, TransCanada and the joint venture entered into an amended agreement to increase the credit facility to MXN$21.3 billion. At December 31, 2017, the Company's consolidated balance sheet included a $919 million loan receivable from the Sur de Texas joint venture which represents TransCanada's proportionate share of the debt financing requirements related to the joint venture. Interest income and other included interest income of $34 million in 2017 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

The NGTL System's 2017 and 2016 results reflect the terms of the 2016-2017 Revenue Requirement Settlement approved by the NEB in April 2016. This settlement includes an ROE of 10.1 per cent on 40 per cent deemed equity, a composite depreciation rate of approximately 3.16 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.

The NGTL System's 2015 results reflect the terms of the 2015 Revenue Requirement Settlement. This one-year settlement included a 10.1 per cent ROE on deemed common equity of 40 per cent, a composite depreciation rate of approximately 3.1 per cent, a mechanism for sharing variances above and below a fixed annual 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 continued 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 six-year fixed toll term of the NEB 2014 Decision. As directed by the NEB, the Canadian Mainline filed an application for approval of 2018-2020 tolls on December 18, 2017.

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.

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.

ANR Pipeline Company

ANR Pipeline Company previously operated under rates established pursuant to a settlement approved by the FERC that was effective for all periods presented beginning in 1997 through July 31, 2016. Effective August 1, 2016, ANR Pipeline Company began operating under new rates pursuant to a FERC-approved rate settlement in September 2016. Under terms of the September 2016 settlement, neither ANR Pipeline Company nor the settling parties can file for new rates to become effective earlier than August 1, 2019. However, ANR Pipeline Company is required to file for new rates to be effective no later than August 1, 2022.

Great Lakes

On October 30, 2017, Great Lakes filed a rate settlement with 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 Settlement). The 2017 Great Lakes Settlement, if approved by FERC, will result in a decrease in Great Lakes' maximum transportation rates effective October 1, 2017. The 2017 Great Lakes Settlement does not contain any 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.

Columbia Gulf

Columbia Gulf's natural gas transportation services are provided under a tariff at rates subject to FERC approval. In September 2016, the 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 requires 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.

Mexico Regulated Operations

TransCanada's Mexico natural gas pipelines operations 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.

Regulatory Assets and Liabilities

at December 31 (millions of Canadian $)	2017	2016	Remaining Recovery/ Settlement Period (years)
Regulatory Assets			
Deferred income taxes[1]	**967**	861	n/a
Deferred income taxes – U.S. Tax Reform[2]	**(27)**	—	n/a
Operating and debt-service regulatory assets[3]	**—**	1	1
Pensions and other post-retirement benefits[1,4]	**388**	382	n/a
Foreign exchange on long-term debt[1,5]	**—**	37	1-12
Other	**71**	74	n/a
	1,399	1,355	
Less: Current portion included in Other current assets (Note 7)	**23**	33	
	1,376	1,322	
Regulatory Liabilities			
Operating and debt-service regulatory liabilities[3]	**188**	47	1
Pensions and other post-retirement benefits[4]	**164**	180	n/a
ANR related post-employment and retirement benefits other than pension[6]	**66**	141	n/a
Long term adjustment account[7]	**1,142**	659	46
Pipeline abandonment trust balance	**825**	541	n/a
Bridging amortization account[7]	**202**	451	13
Cost of removal[8]	**216**	226	n/a
Deferred income taxes	**75**	—	n/a
Deferred income taxes – U.S. Tax Reform[2]	**1,659**	—	n/a
Other	**47**	54	n/a
	4,584	2,299	
Less: Current portion included in Accounts payable and other (Note 14)	**263**	178	
	4,321	2,121	

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 These balances represent the impact of U.S. Tax Reform. The regulatory assets and regulatory liabilities will be amortized over varying terms that approximate the expected reversal of the underlying deferred tax assets and liabilities that gave rise to the regulatory assets and liabilities. See Note 16, Income taxes, for further information.

3 Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determining tolls for the following calendar years.

4 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 customers in future rates.

5 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.

6 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, $26 million (US$21 million) of the regulatory liability balance at December 31, 2017 (2016 – $46 million, US$34 million) which accumulated between January 2007 and July 2016 will be fully amortized at July 31, 2019. The remaining $40 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.

7 These regulatory accounts are used to capture Canadian Mainline revenue and cost variances plus toll stabilization during the 2015-2030 settlement term.

8 This balance represents anticipated costs of removal that have been, and continue to be, included in depreciation rates and collected in the service rates of certain rate-regulated subsidiaries for future costs to be incurred.

11. GOODWILL

The Company has recorded the following Goodwill on its acquisitions in the U.S.:

(millions of Canadian $)	U.S. Natural Gas Pipelines	Energy	Total
Balance at January 1, 2016	3,667	1,145	4,812
Acquisition of Columbia (Note 5)	10,078	—	10,078
Impairment charge	—	(1,085)	(1,085)
Foreign exchange rate changes	213	(60)	153
Balance at December 31, 2016	13,958	—	13,958
Columbia adjustment (Note 5)	**71**	**—**	**71**
Foreign exchange rate changes	**(945)**	**—**	**(945)**
Balance at December 31, 2017	**13,084**	**—**	**13,084**

At December 31, 2017, 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. Assumptions used in the analysis regarding Great Lakes' ability to realize long-term value in the North American energy market included the reduction in Great Lakes' rates effective October 1, 2017 as a result of the expected outcome of the 2017 Great Lakes Settlement. The reduction in rates was offset by expected cash flows from the long-term transportation contract with the Canadian Mainline, other opportunities to increase utilization on the system and the 2017 Great Lakes Settlement's elimination of the revenue sharing mechanism with its customers. 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 relating to Great Lakes. The goodwill balance related to Great Lakes at December 31, 2017 was US$573 million (2016 – US$573 million).

As a result of information received during the process to monetize the Company's U.S. Northeast power business in third quarter2016, 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 approach 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 $)	2017	2016
Capital projects in development	**596**	2,094
Deferred income tax assets (Note 16)	**316**	392
Employee post-retirement benefits (Note 23)	**193**	189
Fair value of derivative contracts (Note 24)	**73**	133
Other	**306**	218
	1,484	3,026

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, are 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 issued notice to the Balancing Pool of the decision to terminate 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. 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 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. Upon final settlement of the PPA terminations 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.

Amortization expense of $9 million was recognized in the Consolidated statement of income for the year ended December 31, 2016 (2015 – $52 million), prior to the termination of the PPAs.

13. NOTES PAYABLE

(millions of Canadian $, unless otherwise noted)	2017 Outstanding at December 31	2017 Weighted Average Interest Rate per Annum at December 31	2016 Outstanding at December 31	2016 Weighted Average Interest Rate per Annum at December 31
Canadian	**884**	**1.6%**	509	0.9%
U.S. (2017 – US$688; 2016 – US$197)	**862**	**2.2%**	265	0.5%
MXN (2017 – MXN$275)	**17**	**8.0%**	—	—
	1,763		774	

At December 31, 2017, Notes payable consists of short-term borrowing by TransCanada PipeLines Limited (TCPL), TransCanada American Investments Ltd. (TAIL), TransCanada PipeLine USA Ltd. (TCPL USA), Columbia and a Mexican subsidiary.

At December 31, 2017, total committed revolving and demand credit facilities were $11.0 billion (2016 – $11.1 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)			2017		2016
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 2022	**3.0**	**3.0**	3.0
TCPL	Supports TCPL's U.S. dollar commercial paper program and for general corporate purposes	December 2018	**US 2.0**	**US 2.0**	US 2.0
TCPL USA	Used for TCPL USA general corporate purposes, guaranteed by TCPL	December 2018	**US 1.0**	**US 0.6**	US 1.0
Columbia	Used for Columbia general corporate purposes, guaranteed by TCPL	December 2018	**US 1.0**	**US 1.0**	US 1.0
TAIL	Supports TAIL's U.S. dollar commercial paper program and for general corporate purposes, guaranteed by TCPL	December 2018	**US 0.5**	**US 0.5**	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	**1.9**	**0.5**	1.9
Mexican subsidiary	Used for Mexico general corporate purposes, guaranteed by TCPL	Demand	**MXN 5.0**	**MXN 4.7**	—

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, 2017, the Company was in compliance with all debt covenants.

For the year ended December 31, 2017, the cost to maintain the above facilities was $7 million (2016 – $10 million; 2015 – $11 million).

At December 31, 2017, the Company's operated affiliates had an additional $0.4 billion (2016 – $0.5 billion) of undrawn capacity on committed credit facilities.

14. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	2017	2016
Trade payables	**2,847**	2,443
Fair value of derivative contracts (Note 24)	**387**	607
Unredeemed shares of Columbia	**312**	317
Regulatory liabilities (Note 10)	**263**	178
Other	**248**	316
	4,057	3,861

15. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	2017	2016
Employee post-retirement benefits (Note 23)	**389**	448
Fair value of derivative contracts (Note 24)	**72**	330
Asset retirement obligations	**98**	108
Guarantees (Note 27)	**16**	82
Other	**152**	215
	727	1,183

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, 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 deferred income tax expense of $816 million.

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 on the Consolidated balance sheet in the amount of $1,686 million.

Net deferred income tax liabilities related to the cumulative remeasurements of employee post-retirement benefits included in AOCI have been adjusted with a corresponding increase in deferred income tax expense of $12 million.

Given the significance of the legislation, the Securities and Exchange Commission (SEC) staff issued guidance which allows registrants to record provisional amounts which may be adjusted as information becomes available, prepared or analyzed during a measurement period not to exceed one year.

The SEC guidance summarizes 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 considers all amounts recorded related to U.S. Tax Reform to be reasonable estimates. Amounts related to businesses subject to RRA are provisional as the Company’s interpretation, assessment and presentation of the impact of the tax law change, may be further clarified with additional guidance from regulatory, tax and accounting authorities. Should additional guidance be provided by these authorities or other sources during the one-year measurement period, TransCanada will review the provisional amounts and adjust as appropriate.

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	2017	2016	2015
Current			
Canada	**113**	116	44
Foreign	**36**	40	92
	149	156	136
Deferred			
Canada	**(185)**	101	33
Foreign	**751**	95	(135)
Foreign – U.S. Tax Reform	**(804)**	—	—
	(238)	196	(102)
Income Tax (Recovery)/Expense	**(89)**	352	34

Geographic Components of Income/(Loss) before Income Taxes

year ended December 31 (millions of Canadian $)	2017	2016	2015
Canada	**(339)**	219	(624)
Foreign	**3,645**	618	(482)
Income/(Loss) before Income Taxes	**3,306**	837	(1,106)

Reconciliation of Income Tax (Recovery)/Expense

year ended December 31 (millions of Canadian $)	2017	2016	2015
Income/(loss) before income taxes	**3,306**	837	(1,106)
Federal and provincial statutory tax rate	**27%**	**27%**	**26%**
Expected income tax expense/(recovery)	**893**	226	(288)
U.S. Tax Reform	**(804)**	—	—
Foreign income tax rate differentials	**(81)**	(196)	14
Income from equity investments and non-controlling interests	**(64)**	(68)	(56)
Income tax differential related to regulated operations	**(42)**	81	159
Non-taxable portion of capital gains	**(42)**	—	—
Asset impairment charges[1]	**34**	242	170
Non-deductible amounts	**4**	46	—
Tax rate and legislative changes	**—**	—	34
Other	**13**	21	1
Income Tax (Recovery)/Expense	**(89)**	352	34

1 Net of nil (2016 — $112 million; 2015 — $311 million) attributed to higher foreign tax rates.

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	2017	2016
Deferred Income Tax Assets		
Tax loss and credit carryforwards	**1,379**	2,063
Difference in accounting and tax bases of impaired assets and assets held for sale	**651**	1,168
Regulatory and other deferred amounts	**512**	277
Unrealized foreign exchange losses on long-term debt	**216**	446
Financial instruments	**10**	34
Other	**227**	352
	2,995	4,340
Less: valuation allowance	**832**	1,336
	2,163	3,004
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment and PPAs	**6,240**	9,015
Equity investments	**632**	905
Taxes on future revenue requirement	**238**	198
Other	**140**	156
	7,250	10,274
Net Deferred Income Tax Liabilities	**5,087**	7,270

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

at December 31 (millions of Canadian $)	2017	2016
Deferred Income Tax Assets		
Intangible and other assets (Note 12)	**316**	392
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**5,403**	7,662
Net Deferred Income Tax Liabilities	**5,087**	7,270

At December 31, 2017, the Company has recognized the benefit of unused non-capital loss carryforwards of $1,280 million (2016 – $1,786 million) for federal and provincial purposes in Canada, which expire from 2030 to 2037. The Company has not recognized the benefit of capital loss carry forwards of $668 million (2016 – $654 million) for federal and provincial purposes in Canada. The Company also has Ontario minimum tax credits of $82 million (2016 – $68 million), which expire from 2026 to 2037.

At December 31, 2017, the Company has recognized the benefit of unused net operating loss carryforwards of US$1,800 million (2016 – US$2,545 million) for federal purposes in the U.S., which expire from 2028 to 2037. The Company has not recognized the benefit of unused net operating loss carryforwards of US$710 million (2016 – US$58 million) for federal purposes in the U.S. The Company also has alternative minimum tax credits of US$56 million (2016 – US$37 million).

At December 31, 2017, the Company has recognized the benefit of unused net operating loss carryforwards of US$7 million (2016 – US$54 million) in Mexico, which expire from 2024 to 2027.

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, 2017 by approximately $569 million (2016 – $481 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $247 million, net of refunds, were made in 2017 (2016 – payments, net of refunds, of $105 million; 2015 – payments, net of refunds, of $162 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 $)	2017	2016	2015
Unrecognized tax benefit at beginning of year	**18**	17	18
Gross increases – tax positions in prior years	**—**	3	2
Gross decreases – tax positions in prior years	**(1)**	—	(2)
Gross increases – tax positions in current year	**2**	2	1
Settlement	**—**	(1)	—
Lapse of statutes of limitations	**(4)**	(3)	(2)
Unrecognized Tax Benefit at End of Year	**15**	18	17

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 2009. Substantially all material U.S. federal, state and local income tax matters have been concluded for years through 2010.

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, 2017 reflects nil of interest expense and nil for penalties (2016 – nil of interest expense and nil for penalties; 2015 – $1 million reversal of interest expense and nil for penalties). At December 31, 2017, the Company had $4 million accrued for interest expense and nil accrued for penalties (December 31, 2016 – $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	2017 Outstanding at December 31	2017 Interest Rate[1]	2016 Outstanding at December 31	2016 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian	2018 to 2020	**500**	**10.8%**	600	10.7%
U.S. (2017 and 2016 – US$400)	2021	**501**	**9.9%**	537	9.9%
Medium Term Notes					
Canadian	2019 to 2047	**6,504**	**4.9%**	5,804	4.6%
Senior Unsecured Notes					
U.S. (2017 – US$14,892; 2016 – US$14,642)	2018 to 2045	**18,644**	**5.1%**	19,660	5.1%
Acquisition Bridge Facility (2017 – nil; 2016 – US$2,013)	—	**—**	**—**	2,702	1.9%
		26,149		29,303	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian	2024	**100**	**9.9%**	100	9.9%
U.S. (2017 and 2016 – US$200)	2023	**250**	**7.9%**	269	7.9%
Medium Term Notes					
Canadian	2025 to 2030	**504**	**7.4%**	504	7.4%
U.S. (2017 and 2016 – US$33)	2026	**41**	**7.5%**	44	7.5%
		895		917	
TRANSCANADA PIPELINE USA LTD.					
Acquisition Bridge Facility (2017 – nil; 2016 – US$1,700)	—	**—**	**—**	2,283	1.9%
COLUMBIA PIPELINE GROUP, INC.					
Senior Unsecured Notes					
U.S. (2017 and 2016 – US$2,750)[2]	2018 to 2045	**3,443**	**4.0%**	3,692	4.0%
TC PIPELINES, LP					
Unsecured Loan Facility					
U.S. (2017 – US$185; 2016 – US$160)	2021	**232**	**2.7%**	215	1.9%
Unsecured Term Loan					
U.S. (2017 and 2016 – US$670)[3]	2020 to 2022	**839**	**2.7%**	899	1.9%
Senior Unsecured Notes					
U.S. (2017 – US$1,200; 2016 – US$700)	2021 to 2027	**1,502**	**4.4%**	940	4.7%
		2,573		2,054	
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2017 and 2016 – US$672)	2021 to 2026	**842**	**7.2%**	903	7.2%
GAS TRANSMISSION NORTHWEST LLC					
Unsecured Term Loan					
U.S. (2017 – US$55; 2016 – US$65)	2019	**69**	**1.1%**	87	1.6%
Senior Unsecured Notes					
U.S. (2017 and 2016 – US$250)	2020 to 2035	**313**	**5.6%**	336	5.6%
		382		423	
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. (2017 – US$259; 2016 – US$278)	2018 to 2030	**324**	**7.7%**	373	7.7%

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2017 Outstanding at December 31	2017 Interest Rate[1]	2016 Outstanding at December 31	2016 Interest Rate[1]
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes[4]					
U.S. (2017 – US$30; 2016 – US$53)	2018	**38**	**6.0%**	71	6.0%
TUSCARORA GAS TRANSMISSION COMPANY					
Unsecured Term Loan					
U.S. (2017 – US$25; 2016 – US$10)	2020	**31**	**1.1%**	13	1.9%
Senior Secured Notes					
U.S. (2017 – nil; 2016 – US$12)	—	**—**	**—**	16	4.0%
		31		29	
		34,677		40,048	
Current portion of long-term debt		**(2,866)**		(1,838)	
Unamortized debt discount and issue costs		**(174)**		(191)	
Fair value adjustments[5]		**238**		293	
		31,875		38,312	

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. 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$170 million and US$500 million term loan facilities were amended in September 2017 to extend the maturity dates from 2018 to 2020 and 2022, respectively.

4 These notes are secured by shipper transportation contracts, existing and new guarantees, letters of credit and collateral requirements.

5 The fair value adjustments include $242 million (2016 – $293 million) related to the acquisition of Columbia. Refer to Note 5, Acquisition of Columbia, for further information. The fair value adjustments also include a decrease of $4 million (2016 – nil) related to hedged interest rate risk. Refer to Note 24, Risk management and financial instruments, for further information.

Principal Repayments

At December 31, 2017, principal repayments for the next five years on the Company's Long-term debt are approximately as follows:

(millions of Canadian $)	2018	2019	2020	2021	2022
Principal repayments on long-term debt	2,866	3,189	2,834	2,085	1,929

Long-Term Debt Issued

The Company issued long-term debt over the three years ended December 31, 2017 as follows:

(millions of Canadian $, unless otherwise noted)					
Company	**Issue Date**	**Type**	**Maturity Date**	**Amount**	**Interest Rate**
TRANSCANADA PIPELINES LIMITED					
	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[1]	June 2018	US 5,213	Floating
	June 2016	Medium Term Notes	July 2023	300	3.69% [2]
	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%
	November 2015	Senior Unsecured Notes	November 2017	US 1,000	1.625%
	October 2015	Medium Term Notes	November 2041	400	4.55%
	July 2015	Medium Term Notes	July 2025	750	3.30%
	March 2015	Senior Unsecured Notes	March 2045	US 750	4.60%
	January 2015	Senior Unsecured Notes	January 2018	US 500	1.875%
	January 2015	Senior Unsecured Notes	January 2018	US 250	Floating
TUSCARORA GAS TRANSMISSION COMPANY					
	August 2017	Term Loan	August 2020	US 25	Floating
	April 2016	Term Loan	April 2019	US 10	Floating
TC PIPELINES, LP					
	May 2017	Senior Unsecured Notes	May 2027	US 500	3.90%
	September 2015	Unsecured Term Loan	October 2018	US 170	Floating
	March 2015	Senior Unsecured Notes	March 2025	US 350	4.375%
TRANSCANADA PIPELINE USA LTD.					
	June 2016	Acquisition Bridge Facility[1]	June 2018	US 1,700	Floating
ANR PIPELINE COMPANY					
	June 2016	Senior Unsecured Notes	June 2026	US 240	4.14%
GAS TRANSMISSION NORTHWEST LLC					
	June 2015	Unsecured Term Loan	June 2019	US 75	Floating

1 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 the second quarter 2017.

2 Reflects coupon rate on re-opening of a pre-existing medium term notes (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, 2017 as follows:

(millions of Canadian $, unless otherwise noted) Company	Retirement/Repayment Date	Type	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED				
	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%
	August 2015	Debentures	150	11.90%
	June 2015	Senior Unsecured Notes	US 500	3.40%
	March 2015	Senior Unsecured Notes	US 500	0.875%
	January 2015	Senior Unsecured Notes	US 300	4.875%
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%
GAS TRANSMISSION NORTHWEST LLC				
	June 2015	Senior Unsecured Notes	US 75	5.09%

1 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 the second quarter 2017.

Interest Expense

Interest expense in the three years ended December 31 was as follows:

year ended December 31 (millions of Canadian $)	2017	2016	2015
Interest on long-term debt	**1,794**	1,765	1,487
Interest on junior subordinated notes	**348**	180	116
Interest on short-term debt	**33**	18	16
Capitalized interest	**(173)**	(176)	(280)
Amortization and other financial charges[1]	**67**	211	31
	2,069	1,998	1,370

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 $1,987 million in 2017 (2016 – $1,721 million; 2015 – $1,266 million) on long-term debt, junior subordinated notes and notes payable, net of interest capitalized.

18. JUNIOR SUBORDINATED NOTES

Outstanding loan amount (millions of Canadian $, unless otherwise noted)	Maturity Date	2017 Outstanding at December 31	2017 Effective Interest Rate	2016 Outstanding at December 31	2016 Effective Interest Rate
TRANSCANADA PIPELINES LIMITED					
U.S.$1,000 notes issued 2007[1]	2067	**1,252**	**5.0%** [3]	1,343	6.4%
U.S.$750 notes issued 2015[1,2]	2075	**939**	**5.9%**	1,007	5.5%
U.S.$1,200 notes issued 2016[1,2]	2076	**1,502**	**6.6%**	1,611	6.2%
U.S.$1,500 notes issued 2017[1, 2]	2077	**1,878**	**5.6%**	—	—
$1,500 notes issued 2017 [1, 2]	2077	**1,500**	**5.1%**	—	—
		7,071		3,961	
Unamortized debt discount and issue costs		**(64)**		(30)	
		7,007		3,931	

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

2 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.

3 In May 2017, Junior subordinated notes of US $1 billion converted from 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.

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 then three 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 three month LIBOR plus 4.89 per cent per annum; from August 2046 to August 2076 the interest rate will reset to the 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 $)	2017	2016
Non-controlling interest in TC PipeLines, LP	**1,852**	1,596
Non-controlling interest in Portland Natural Gas Transmission System	**—**	130
	1,852	1,726

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

year ended December 31 (millions of Canadian $)	2017	2016	2015
Non-controlling interest in TC PipeLines, LP	**220**	215	(13)
Non-controlling interest in Portland Natural Gas Transmission System[1]	**9**	20	19
Non-controlling interest in Columbia Pipeline Partners LP[2]	**9**	17	—
	238	252	6

1 Non-controlling interest in 2017 for the period January 1 to May 31 when TransCanada sold its remaining interest in PNGTS to TC PipeLines, LP. Refer to Note 26, Other acquisitions and dispositions for further information.

2 Non-controlling interest up to February 17, 2017 acquisition of all publicly held common units of CPPL.

TC PipeLines, LP

During 2017, the non-controlling interest in TC PipeLines, LP increased from 73.2 per cent to 74.3 per cent due to periodic issuances of common units in TC PipeLines, LP to third parties under an at-the-market issuance program (ATM program). In 2016, the non-controlling interest in TC PipeLines, LP ranged between 72.0 per cent and 73.2 per cent and, in 2015, between 71.7 per cent and 72.0 per cent.

In December 2015, TC PipeLines, LP recorded an impairment charge of US$199 million related to its equity investment in Great Lakes. The non-controlling interest's share of this charge was US$143 million and was included in the Net income attributable to non-controlling interests in 2015.

Portland Natural Gas Transmission System

On June 1, 2017, TransCanada sold its remaining 11.81 per cent directly held interest in Portland Natural Gas Transmission System (PNGTS) to TC PipeLines, LP and, as a result, at December 31, 2017, non-controlling interest in PNGTS was nil. The non-controlling interest in PNGTS as at December 31, 2016 represented the 38.3 per cent interest held by third parties. On January 1, 2016, TransCanada sold 49.9 per cent of PNGTS to TC PipeLines, LP. Refer to Note 26, Other acquisitions and dispositions for further information.

In 2017, TransCanada received fees of $5 million from TC PipeLines, LP (2016 – $5 million and 2015 – $4 million) and $4 million from PNGTS prior to June 1, 2017 (2016 – $10 million; 2015 – $11 million) for services provided.

Columbia Pipeline Partners LP

On July 1, 2016, TransCanada acquired Columbia, which included a 53.5 per cent non-controlling interest in 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 ATM 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 have 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, 2015	708,662	12,202
Exercise of options	737	30
Repurchase of shares	(6,785)	(130)
Outstanding at December 31, 2015	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**

1 Net of underwriting commissions and deferred income taxes.

Common Shares Issued and Outstanding

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

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. Common shares are 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 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 ATM program, the Company can 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 gross proceeds of$218 million. Related commissions and fees were approximately$2 million, resulting in net proceeds of$216 million.

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 closing of 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.

In December 2015, the Company repurchased 6,784,738 of its common shares at an average price of $43.29 for a total of $294 million. These shares had a weighted average cost of $130 million with the difference of $164 million between the total price paid and the weighted average cost recorded in Additional paid-in capital.

Basic and Diluted Net Income/(Loss) per Common Share

Net income/(loss) per common share is calculated by dividing Net income/(loss) attributable to common shares by the weighted average number of common shares outstanding. The 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 outstanding shares issued under the DRP.

Weighted Average Common Shares Outstanding (millions)	**2017**	**2016**	**2015**
Basic	**872**	759	709
Diluted	**874**	760	709

Stock Options

	Number of Options (thousands)	**Weighted Average Exercise Prices**	**Weighted Average Remaining Contractual Life** (years)
Options outstanding at January 1, 2017	10,630	$48.28	
Options granted	**2,066**	**$62.22**	
Options exercised	**(1,331)**	**$42.03**	
Options forfeited/expired	**(339)**	**$56.89**	
Options Outstanding at December 31, 2017	**11,026**	**$51.38**	**3.9**
Options Exercisable at December 31, 2017	**6,559**	**$48.59**	**3.0**

At December 31, 2017, an additional 11,902,759 common shares were reserved for future issuance 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	2017	2016	2015
Weighted average fair value	**$7.22**	$5.67	$6.45
Expected life (years)	**5.7**	5.8	5.8
Interest rate	**1.2%**	0.7%	1.1%
Volatility[1]	**18%**	21%	18%
Dividend yield	**3.6%**	4.9%	3.7%
Forfeiture rate[2]	**—**	5%	5%

1 Volatility is derived based on the average of both the historical and implied volatility of the Company's common shares.
2 On January 1, 2017, TransCanada made an election to account for forfeitures when they occur as a result of new GAAP guidance. Refer to Note 3, Accounting changes, for further information.

The amount expensed for stock options, with a corresponding increase in Additional paid-in capital, was $12 million in 2017 (2016 – $15 million; 2015 – $13 million). At December 31, 2017, unrecognized compensation costs related to non-vested stock options was $15 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)	2017	2016	2015
Total intrinsic value of options exercised	**28**	31	10
Fair value of options that have vested	**140**	126	91
Total options vested	**2.3 million**	2.1 million	2.0 million

As at December 31, 2017, the aggregate intrinsic value of the total options exercisable was $83 million and the total intrinsic value of options outstanding was $110 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]	2017	2016	2015
							(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	342
Series 6	1,286	Floating [4]	Floating	$25.00	January 30, 2021	Series 5	**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	—
Series 15	40,000	4.90%	$1.225	$25.00	May 31, 2022	Series 16	**988**	988	—
							3,980	3,980	2,499

1 Each of the even numbered series of preferred shares, if in existence, will be entitled to receive floating rate cumulative quarterly preferential dividends per share at an annualized rate equal to the 90-day Government of Canada Treasury bill rate (T-bill rate) plus 1.92 per cent (Series 2), 1.28 per cent (Series 4), 1.54 per cent (Series 6), 2.38 per cent (Series 8), 2.35 per cent (Series 10), 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 2.792 per cent and for the Series 4 preferred shares is 2.152 per cent for the period starting December 29, 2017 to, but excluding, March 29, 2018. The floating quarterly dividend rate for the Series 6 preferred shares is 2.549 per cent for the period starting October 30, 2017 to, but excluding, January 30, 2018. 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.

In March 2015, TransCanada completed a public offering of 10 million Series 11 cumulative redeemable first preferred shares at $25 per share, resulting in gross proceeds of $250 million.

In June 2015, holders of 5,466,595 Series 3 cumulative redeemable first preferred shares exercised their option to convert to Series 4 cumulative first preferred shares.

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 (LOSS)/INCOME AND ACCUMULATED OTHER COMPREHENSIVE LOSS

Components of Other comprehensive (loss)/income, including the portion attributable to non-controlling interests and related tax effects, are as follows:

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 net investment on disposal of foreign operations	**(77)**	**—**	**(77)**
Change in fair value of net investment hedges	**—**	**—**	**—**
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)

year ended December 31, 2015 (millions of Canadian $)	Before Tax Amount	Income Tax Recovery/(Expense)	Net of Tax Amount
Foreign currency translation gains on net investment in foreign operations	798	15	813
Change in fair value of net investment hedges	(505)	133	(372)
Change in fair value of cash flow hedges	(92)	35	(57)
Reclassification to net income of gains and losses on cash flow hedges	144	(56)	88
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	74	(23)	51
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	41	(9)	32
Other comprehensive income on equity investments	62	(15)	47
Other Comprehensive Income	522	80	602

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, 2015	(518)	(128)	(281)	(308)	(1,235)
Other comprehensive income/(loss) before reclassifications[2]	135	(57)	51	33	162
Amounts reclassified from AOCI	—	88	32	14	134
Net current period other comprehensive income	135	31	83	47	296
AOCI balance at December 31, 2015	(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[4]	**(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)**

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.

2 In 2017, other comprehensive (loss)/income before reclassifications on currency translation adjustments and cash flow hedges is net of non-controlling interest losses of $159 million (2016 – $14 million losses; 2015 – $306 million gains) and gains of $4 million (2016 – $3 million gains and 2015 – nil), 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 $19 million ($14 million, net of tax) at December 31, 2017. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

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

year ended December 31 (millions of Canadian $)	Amounts Reclassified From AOCI[1] 2017	2016	2015	Affected Line Item in the Consolidated Statement of Income
Cash flow hedges				
Commodities	**20**	(57)	(128)	Revenues (Energy)
Interest	**(17)**	(14)	(16)	Interest expense
	3	(71)	(144)	Total before tax
	(1)	29	56	Income tax (recovery)/expense
	2	(42)	(88)	Net of tax
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial loss and past service cost	**(15)**	(22)	(41)	Plant operating costs and other[2]
Settlement charge	**(2)**	—	—	Plant operating costs and other[2]
	(17)	(22)	(41)	Total before tax
	5	6	9	Income tax (recovery)/expense
	(12)	(16)	(32)	Net of tax
Equity investments				
Equity income	**(15)**	(19)	(19)	Income from equity investments
	4	5	5	Income tax (recovery)/expense
	(11)	(14)	(14)	Net of tax
Currency translation adjustments				
Realization of foreign currency translation gains on disposal of foreign operations	**77**	—	—	Gain/(loss) on sale of assets held for sale/sold
	—	—	—	Income tax (recovery)/expense
	77	—	—	Net of tax

1 All 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.

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, 2017 (2016 and 2015 – nine years).

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.

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 DC plan. This election was effective December 31, 2017.

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 are amortized out of AOCI over the expected average remaining service life of employees, which was approximately 12 years at December 31, 2017 (2016 and 2015 – 12 years). In 2017, the Company expensed $42 million (2016 – $52 million; 2015 – $41 million) for the savings and DC Plans.

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

year ended December 31 (millions of Canadian $)	2017	2016	2015
DB Plans	**163**	111	96
Other post-retirement benefit plans	**7**	8	6
Savings and DC Plans	**42**	52	41
	212	171	143

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 $27 million letter of credit to the Canadian DB Plan in 2017 (2016 – $20 million; 2015 – $33 million), resulting in a total of $260 million provided to the Canadian DB Plan under letters of credit at December 31, 2017.

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2017 and the next required valuation will be as at January 1, 2018.

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 in 2017 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 Other comprehensive income, 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.

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. All other assumptions were consistent with those employed at December 31, 2016. 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 Other comprehensive income.

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 $)	2017	2016	2017	2016
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**3,456**	2,780	**372**	225
Service cost	**113**	107	**4**	3
Interest cost	**135**	127	**14**	13
Employee contributions	**5**	4	**3**	2
Benefits paid	**(166)**	(204)	**(19)**	(16)
Actuarial loss/(gain)	**253**	111	**19**	(8)
Acquisition of Columbia	**—**	527	**—**	151
Curtailment	**(14)**	—	**(2)**	—
Settlement	**(66)**	2	**—**	—
Foreign exchange rate changes	**(70)**	2	**(16)**	2
Benefit obligation – end of year	**3,646**	3,456	**375**	372
Change in Plan Assets				
Plan assets at fair value – beginning of year	**3,208**	2,591	**354**	45
Actual return on plan assets	**358**	227	**45**	14
Employer contributions[2]	**163**	111	**7**	8
Employee contributions	**5**	4	**3**	2
Benefits paid	**(166)**	(204)	**(19)**	(16)
Acquisition of Columbia	**—**	475	**—**	294
Settlement	**(57)**	—	**—**	—
Foreign exchange rate changes	**(60)**	4	**(25)**	7
Plan assets at fair value – end of year	**3,451**	3,208	**365**	354
Funded Status – Plan Deficit	**(195)**	(248)	**(10)**	(18)

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 $260 million in letters of credit provided to the Canadian DB Plan for funding purposes (2016 – $233 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 $)	2017	2016	2017	2016
Intangible and other assets (Note 12)	**—**	—	**193**	189
Accounts payable and other	**(1)**	—	**(8)**	(7)
Other long-term liabilities (Note 15)	**(194)**	(248)	**(195)**	(200)
	(195)	(248)	**(10)**	(18)

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 $)	2017	2016	2017	2016
Projected benefit obligation[1]	**(3,646)**	(3,456)	**(203)**	(207)
Plan assets at fair value	**3,451**	3,208	**—**	—
Funded Status – Plan Deficit	**(195)**	(248)	**(203)**	(207)

1 The projected benefit obligation for the pension benefit plan differs from the accumulated benefit obligation in that it includes an assumption with respect to future compensation levels.

The funded status based on the accumulated benefit obligation for all DB Plans is as follows:

at December 31		
(millions of Canadian $)	2017	2016
Accumulated benefit obligation	**(3,372)**	(3,202)
Plan assets at fair value	**3,451**	3,208
Funded Status – Plan Surplus	**79**	6

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 $)	2017	2016
Accumulated benefit obligation	**(944)**	(990)
Plan assets at fair value	**925**	868
Funded Status – Plan Deficit	**(19)**	(122)

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	2017	2016	2017
Debt securities	**30%**	31%	**25% to 40%**
Equity securities	**64%**	63%	**45% to 75%**
Alternatives	**6%**	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 $)	2017	2016	2017	2016
Debt securities	**7**	9	**0.2%**	0.2%
Equity securities	**3**	4	**0.1%**	0.1%

Pension plan assets are managed on a going concern basis, subject to legislative restrictions, and are diversified across asset classes to maximize returns at an acceptable level of risk. Asset mix strategies consider plan demographics and may include traditional equity and debt securities, as well as alternative assets such as infrastructure, private equity, real estate and derivatives to diversify risk. Derivatives are not used for speculative purposes and the use of leveraged derivatives is prohibited.

All investments are measured at fair value using market prices. Where the fair value cannot be readily determined by reference to generally available price quotations, the fair value is determined by considering the discounted cash flows on a risk-adjusted basis and by comparison to similar assets which are publicly traded. In Level I, the fair value of assets is determined by reference to quoted prices in active markets for identical assets that the Company has the ability to access at the measurement date. In Level II, the fair value of assets is determined using valuation techniques, such as option pricing models and extrapolation using significant inputs, which are observable directly or indirectly. In Level III, the fair value of assets is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement.

The following table presents plan assets for DB Plans and other post-retirement benefits measured at fair value, which have been categorized into the three categories based on a fair value hierarchy. For 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 $)	2017	2016	2017	2016	2017	2016	2017	2016	2017	2016
Asset Category										
Cash and Cash Equivalents	**44**	22	**17**	12	**—**	—	**61**	34	**2**	1
Equity Securities:										
Canadian	**410**	388	**151**	143	**—**	—	**561**	531	**15**	15
U.S.	**543**	504	**354**	476	**—**	—	**897**	980	**24**	27
International	**45**	39	**322**	327	**—**	—	**367**	366	**10**	10
Global	**—**	—	**301**	235	**—**	—	**301**	235	**8**	7
Emerging	**8**	7	**147**	137	**—**	—	**155**	144	**4**	4
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**193**	192	**—**	—	**193**	192	**5**	5
Provincial	**—**	—	**194**	179	**—**	—	**194**	179	**5**	5
Municipal	**—**	—	**8**	8	**—**	—	**8**	8	**—**	—
Corporate	**—**	—	**122**	126	**—**	—	**122**	126	**3**	4
U.S. Bonds:										
Federal	**—**	—	**244**	82	**—**	—	**244**	82	**6**	2
State	**—**	—	**41**	41	**—**	—	**41**	41	**1**	1
Municipal	**—**	—	**4**	39	**—**	—	**4**	39	**—**	1
Corporate	**—**	—	**234**	188	**—**	—	**234**	188	**6**	5
International:										
Government	**—**	—	**4**	6	**—**	—	**4**	6	**—**	—
Corporate	**—**	—	**5**	21	**—**	—	**5**	21	**—**	1
Mortgage backed	**—**	—	**73**	62	**—**	—	**73**	62	**2**	2
Other Investments:										
Real estate	**—**	—	**—**	—	**140**	133	**140**	133	**4**	4
Infrastructure	**—**	—	**—**	—	**70**	58	**70**	58	**2**	2
Private equity funds	**—**	—	**—**	—	**6**	8	**6**	8	**—**	—
Funds held on deposit	**136**	129	**—**	—	**—**	—	**136**	129	**3**	4
	1,186	1,089	**2,414**	2,274	**216**	199	**3,816**	3,562	**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, 2015	14
Purchases and sales	183
Realized and unrealized gains	2
Balance at December 31, 2016	199
Purchases and sales	**11**
Realized and unrealized gains	**6**
Balance at December 31, 2017	**216**

The Company's expected funding contributions in 2018 are approximately $98 million for the DB Plans, approximately $7 million for the other post-retirement benefit plans and approximately $45 million for the savings plan and DC Plans. The Company expects to provide an additional estimated $27 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
2018	181	19
2019	187	20
2020	190	20
2021	196	20
2022	200	20
2023 to 2027	1,054	98

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, 2017. 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	**2017**	**2016**	**2017**	**2016**
Discount rate	**3.60%**	4.00%	**3.70%**	4.15%
Rate of compensation increase	**3.00%**	1.20%	—	—

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	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Discount rate	**3.95%**	4.20%	4.15%	**4.15%**	4.30%	4.20%
Expected long-term rate of return on plan assets	**6.50%**	6.70%	6.95%	**6.05%**	5.95%	4.60%
Rate of compensation increase	**1.20%**	0.80%	3.15%	—	—	—

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 seven per cent weighted average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2018 measurement purposes. The rate was assumed to decrease gradually to five per cent by 2024 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	15	(13)

The Company's net benefit cost recognized is as follows:

at December 31	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
(millions of Canadian $)	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Service cost	**108**	107	108	**4**	3	3
Interest cost	**122**	127	115	**14**	13	10
Expected return on plan assets	**(178)**	(175)	(155)	**(21)**	(11)	(2)
Amortization of actuarial loss	**14**	20	35	**1**	2	3
Amortization of past service cost	**—**	—	2	**—**	—	1
Amortization of regulatory asset	**37**	27	23	**1**	1	1
Amortization of transitional obligation related to regulated business	**—**	—	—	**—**	2	2
Settlement charge – regulatory asset	**2**	—	—	**—**	—	—
Settlement charge – AOCI	**2**	—	—	**—**	—	—
Net Benefit Cost Recognized	**107**	106	128	**(1)**	10	18

Pre-tax amounts recognized in AOCI were as follows:

at December 31 (millions of Canadian $)	2017		2016		2015	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Net loss	**273**	**11**	270	21	247	28

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 2018 is $19 million and $1 million, respectively.

Pre-tax amounts recognized in OCI were as follows:

at December 31 (millions of Canadian $)	2017		2016		2015	
	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 OCI	**(18)**	**(1)**	(20)	(2)	(34)	(4)
Amortization of prior service costs from AOCI to OCI	**—**	**—**	—	—	(2)	(1)
Curtailment	**(14)**	**(2)**	—	—	—	—
Settlement	**(11)**	**—**	—	—	—	—
Funded status adjustment	**46**	**(7)**	43	(5)	(67)	(7)
	3	**(10)**	23	(7)	(103)	(12)

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 and cash flow.

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 ultimately 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.

Power generation commodity price risk

The Company is exposed to commodity price movements as part of its normal business operations. A number of strategies are used to manage these exposures, including the following:

- committing a portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to manage operational and price risks in its asset portfolio
- purchasing a portion of the natural gas required to fuel certain of its power plants or entering into contracts that base the sale price of electricity on the cost of natural gas, effectively locking in a margin
- meeting power sales commitments using power generation or fixed price purchase contracts, thereby reducing the Company's exposure to fluctuating commodity prices.

In April and June 2017, the Company sold its U.S. Northeast power assets. In December 2017, TransCanada entered into an agreement to sell its outstanding U.S. power retail contracts as part of the wind down of the U.S. power marketing operations. The sale of the U.S. power retail contracts is expected to close in the first quarter of 2018, subject to regulatory and other approvals. As a result of these sales, the exposure to commodity price risk has been reduced significantly.

Natural gas storage commodity price risk

TransCanada manages its exposure to seasonal natural gas price spreads in its non-regulated natural gas storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TransCanada simultaneously enters into forward purchase contracts of natural gas for injection into storage and offsetting forward sale contracts of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to natural gas price movements. Unrealized gains and losses on fair value adjustments recorded each period on these forward contracts are not necessarily representative of the amounts that will be realized on settlement.

Liquids marketing commodity price risk

The liquids marketing business began operations in 2016. TransCanada enters into short-term or long-term liquids 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.

Foreign exchange and interest rate risk

Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and interest rates. 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 expected to fluctuate.

A portion of TransCanada's business generates 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 the Company's net income. As the Company's U.S. dollar-denominated operations continue to grow, exposure to changes in currency rates increases. The majority of this risk is offset by interest expense on U.S. dollar-denominated debt and by using foreign exchange derivatives.

TransCanada is exposed to interest rate risk resulting from financial instruments and contractual obligations containing variable interest rate components. The Company uses a combination of interest rate swaps and options to manage its exposure to this risk.

Net investment in foreign operations

The Company hedges its net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps and foreign exchange forward contracts and options.

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

at December 31 (millions of Canadian $, unless otherwise noted)	2017 Fair Value[1]	2017 Notional or Principal Amount	2016 Fair Value[1]	2016 Notional or Principal Amount
U.S. dollar cross-currency interest rate swaps (maturing 2018 to 2019)[2]	**(199)**	**US 1,200**	(425)	US 2,350
U.S. dollar foreign exchange options (maturing 2018)	**5**	**US 500**	—	—
U.S. dollar foreign exchange forward contracts	**—**	**—**	(7)	US 150
	(194)	**US 1,700**	(432)	US 2,500

1 Fair value equals carrying value.

2 In 2017, Net income includes net realized gains of $4 million (2016 – gains of $6 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)	2017	2016
Notional amount	**25,400 (US 20,200)**	26,600 (US 19,800)
Fair value	**28,900 (US 23,100)**	29,400 (US 21,900)

Counterparty Credit Risk

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 using recognized credit management techniques, including:

- dealing with creditworthy counterparties – a significant amount of the Company's credit exposure is with investment grade counterparties or, if not, is generally partially supported by financial assurances from investment grade parties
- setting limits on the amount TransCanada can transact with any one counterparty – the Company monitors and manages the concentration of risk exposure with any one counterparty, and reduces the exposure when necessary and when it is allowed under the terms of the contracts
- using contract netting arrangements and obtaining financial assurances such as guarantees, letters of credit or cash when deemed necessary.

There is no guarantee that these techniques will protect the Company from material losses.

TransCanada's maximum counterparty credit exposure with respect to financial instruments at December 31,2017, without taking into account security held, consisted of cash and cash equivalents, accounts receivable, available for sale assets, derivative assets and loan receivable. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At December 31, 2017, there were no significant amounts past due or impaired,no significant credit risk concentration andno significant credit losses during the year. At December 31, 2016, we had a credit risk concentration with one counterparty of$200 million (US$149 million).

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.

For TransCanada's Canadian regulated natural gas pipeline assets, counterparty credit risk is managed through application of tariff provisions as approved by the NEB.

Fair Value of Non-Derivative Financial Instruments

The fair value of long-term debt and junior subordinated notes is estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data service providers.

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 $)	2017 Carrying Amount	2017 Fair Value	2016 Carrying Amount	2016 Fair Value
Long-term debt, including current portion[1,2] (Note 17)	**(34,741)**	**(40,180)**	(40,150)	(45,047)
Junior subordinated notes (Note 18)	**(7,007)**	**(7,233)**	(3,931)	(3,825)
	(41,748)	**(47,413)**	(44,081)	(48,872)

1 Long-term debt is recorded at amortized cost, except for US$1.1 billion (2016 — US$850 million) that is attributed to hedged risk and recorded at fair value.

2 Net income in 2017 included unrealized gains of $4 million (2016 – gains of $2 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$1.1 billion of long-term debt at December 31, 2017 (2016 – US$850 million). 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:

(millions of Canadian $)	2017 LMCI Restricted Investments	2017 Other Restricted Investments[2]	2016 LMCI Restricted Investments	2016 Other Restricted Investments[2]
Fair value[1]				
Fixed income securities (maturing within 1 year)	**—**	**23**	—	19
Fixed income securities (maturing within 1-5 years)	**—**	**107**	—	117
Fixed income securities (maturing within 5-10 years)	**14**	**—**	9	—
Fixed income securities (maturing after 10 years)	**790**	**—**	513	—
	804	**130**	522	136

1 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.

2 Other restricted investments have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

(millions of Canadian $)	2017 LMCI restricted investments[1]	2017 Other restricted investments[2]	2016 LMCI restricted investments[1]	2016 Other restricted investments[2]
Net unrealized (losses)/gains in the year ended December 31	**(3)**	**1**	(28)	(1)
Net realized (losses)/gains in the year ended December 31[3]	**(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 Unrealized gains and losses on other restricted investments are included in OCI.

3 The realized gains or 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.

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, 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 balance sheet classification of the fair value of derivative instruments as atDecember 31, 2016 is as follows:

at December 31, 2016 (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]	6	—	—	351	357
Foreign exchange	—	—	6	10	16
Interest rate	1	1	—	1	3
	7	1	6	362	376
Intangible and other assets (Note 12)					
Commodities[2]	4	—	—	118	122
Foreign exchange	—	—	10	—	10
Interest rate	1	—	—	—	1
	5	—	10	118	133
Total Derivative Assets	12	1	16	480	509
Accounts payable and other (Note 14)					
Commodities[2]	—	—	—	(330)	(330)
Foreign exchange	—	—	(237)	(38)	(275)
Interest rate	(1)	(1)	—	—	(2)
	(1)	(1)	(237)	(368)	(607)
Other long-term liabilities (Note 15)					
Commodities[2]	—	—	—	(118)	(118)
Foreign exchange	—	—	(211)	—	(211)
Interest rate	—	(1)	—	—	(1)
	—	(1)	(211)	(118)	(330)
Total Derivative Liabilities	(1)	(2)	(448)	(486)	(937)
Total Derivatives	11	(1)	(432)	(6)	(428)

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.

Notional and Maturity Summary

The maturity and notional principal 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, 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	**—**	**—**	**—**	**US 2,931**	**US 2,300**
Millions of Mexican pesos	**—**	**—**	**—**	**MXN 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.

at December 31, 2016	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Purchases[1]	86,887	182	6	—	—
Sales[1]	58,561	147	6	—	—
Millions of U.S. dollars	—	—	—	US 2,394	US 1,550
Maturity dates	2017-2021	2017-2020	2017	2017	2017-2019

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 $)	2017	2016	2015
Derivative instruments held for trading[1]			
Amount of unrealized gains/(losses) in the year			
Commodities[2]	**62**	123	(37)
Foreign exchange	**88**	25	(21)
Interest rate	**(1)**	—	—
Amount of realized (losses)/gains in the year			
Commodities	**(107)**	(204)	(151)
Foreign exchange	**18**	62	(112)
Interest rate	**1**	—	—
Derivative instruments in hedging relationships			
Amount of realized gains/(losses) in the year			
Commodities	**23**	(167)	(179)
Foreign exchange	**5**	(101)	—
Interest rate	**1**	4	8

1 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell commodities are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative instruments held for trading are included net in Interest expense and Interest income and other, respectively.

2 In 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)	2017	2016	2015
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]			
Commodities	**(1)**	39	(92)
Interest rate	**4**	5	—
	3	44	(92)
Reclassification of (losses)/gains on derivative instruments from AOCI to Net income (effective portion)[1]			
Commodities[2]	**(20)**	57	128
Interest rate[3]	**17**	14	16
	(3)	71	144

1 No amounts have been excluded from the assessment of hedge effectiveness. In 2017 and 2016, there were no gains or losses included in Net Income related to ineffective portions. Amounts in parentheses indicate losses recorded to OCI and AOCI.

2 Reported within Revenues on the Consolidated statement of income.

3 Reported within Interest expense on the Consolidated statement of income.

Offsetting of derivative instruments

The Company enters into derivative contracts with the right to offset in the normal course of business as well as in the event of default. 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, 2017:

at December 31, 2017 (millions of Canadian $)	Gross Derivative Instruments Presented on the Balance Sheet	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.

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, 2016:

at December 31, 2016 (millions of Canadian $)	Gross Derivative Instruments Presented on the Balance Sheet	Amounts Available for Offset[1]	Net Amounts
Derivative – Asset			
Commodities	479	(362)	117
Foreign exchange	26	(26)	—
Interest rate	4	(1)	3
	509	(389)	120
Derivative – Liability			
Commodities	(448)	362	(86)
Foreign exchange	(486)	26	(460)
Interest rate	(3)	1	(2)
	(937)	389	(548)

1 Amounts available for offset do not include cash collateral pledged or received.

With respect to the derivative instruments presented above as at December 31, 2017, the Company had provided cash collateral of $165 million (2016 – $305 million) and letters of credit of $30 million (2016 – $27 million) to its counterparties. The Company held nil (2016 – nil) in cash collateral and $3 million (2016 – $3 million) in letters of credit from counterparties on asset exposures at December 31, 2017.

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.

Based on contracts in place and market prices at December 31, 2017, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $2 million (2016 – $19 million), for which the Company has provided collateral in the normal course of business of nil (2016 – nil). If the credit-risk-related contingent features in these agreements were triggered on December 31, 2017, the Company would have been required to provide additional collateral of $2 million (2016 – $19 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 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 fair value of the Company's derivative assets and liabilities measured on a recurring basis, including both current and non-current portions for 2016, are categorized as follows:

at December 31, 2016 (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	134	326	19	479
Foreign exchange	—	26	—	26
Interest rate	—	4	—	4
Derivative Instrument Liabilities:				
Commodities	(102)	(343)	(3)	(448)
Foreign exchange	—	(486)	—	(486)
Interest rate	—	(3)	—	(3)
	32	(476)	16	(428)

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2016.

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)	2017	2016
Balance at beginning of year	**16**	9
Transfers out of Level III	**(19)**	(1)
Total (losses)/gains included in Net income	**(17)**	13
Sales	**(5)**	(3)
Settlements	**18**	(2)
Balance at end of year[1]	**(7)**	16

1 Revenues include unrealized losses attributed to derivatives in the Level III category that were still held at December 31, 2017 of $7 million (2016 — gains 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 increase or decrease, respectively, in the fair value of outstanding derivative instruments included in Level III as at December 31, 2017.

25. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian $)	2017	2016	2015
Increase in Accounts receivable	**(576)**	(482)	(65)
Increase in Inventories	**(38)**	(87)	(3)
Decrease/(increase) in Assets held for sale	**14**	(13)	—
Decrease/(increase) in Other current assets	**189**	328	(272)
Increase/(decrease) in Accounts payable and other	**151**	424	(97)
Increase in Accrued interest	**12**	62	91
(Decrease)/increase in Liabilities related to assets held for sale	**(25)**	16	—
(Increase)/decrease in Operating Working Capital	**(273)**	248	(346)

26. OTHER 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 PNGTS to TC PipeLines, LP. Proceeds from these transactions were US$765 million, before post-closing adjustments. Proceeds were comprised of US$597 million in cash and US$168 million representing a proportionate share of Iroquois and PNGTS debt.

In January 2016, TransCanada closed the sale of a 49.9 per cent interest in PNGTS 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 PNGTS 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.

TC Offshore LLC

In December 2015, the Company entered into an agreement to sell TC Offshore LLC to a third party which resulted in a pre-tax loss on sale of $125 million in 2015. In March 2016, the Company closed the sale which resulted in an additional loss of $4 million pre-tax. Losses from the sale were included in Gain/(loss) on assets held for sale/sold in the Consolidated statement of income.

Gas Transmission Northwest LLC

In April 2015, TransCanada completed the sale of its remaining 30 per cent interest in GTN to TC PipeLines, LP for an aggregate purchase price of US$457 million. Proceeds were comprised of US$264 million in cash, the assumption of US$98 million of a proportional share of GTN debt and US$95 million of new Class B units of TC PipeLines, LP.

Energy

Ontario Solar Assets

On December 19, 2017, the Company completed the sale of its Ontario solar assets to a third party for proceeds of approximately $541 million, before post-closing adjustments. As a result, the Company recorded a gain on sale of approximately $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

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 approximately $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 approximately $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 for US$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.

Bruce Power

In December 2015, TransCanada exercised its option to acquire an additional 14.89 per cent ownership interest in Bruce B from the Ontario Municipal Employees Retirement System for $236 million, increasing its ownership interest to 46.5 per cent. The difference between the purchase price and the underlying carrying value of Bruce B is primarily related to the estimated fair value of the amended agreement with Ontario's Independent Electricity System Operator to extend the operating life of the Bruce Power facility to 2064. In December 2015, Bruce A and Bruce B merged to form a single limited partnership, Bruce Power. This merger was accounted for as a transaction between entities under common control whereby the assets and liabilities of Bruce A and Bruce B were combined at their carrying values. Upon completion of the merger, TransCanada applied equity method accounting to its resulting 48.5 per cent ownership interest in Bruce Power. Prior to the acquisition, TransCanada applied equity method accounting to its 48.9 per cent ownership interest in Bruce A and its 31.6 per cent ownership interest in Bruce B.

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
2018	75	4	71
2019	76	2	74
2020	73	2	71
2021	71	1	70
2022	63	—	63
2023 and thereafter	443	2	441
	801	11	790

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 in 2017 was $93 million (2016 – $145 million; 2015 – $131 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, 2017, TransCanada was committed to approximately $0.3 billion of capital expenditures for its Canadian Natural Gas Pipelines, primarily related to construction costs associated with NGTL System natural gas pipeline projects.

At December 31, 2017, TransCanada was committed to approximately $0.4 billion of capital expenditures for its U.S. Natural Gas Pipelines, primarily related to construction costs associated with Columbia Gas and Columbia Gulf growth projects.

At December 31, 2017, TransCanada was committed to approximately $0.7 billion of capital expenditures for its Mexico Natural Gas Pipelines, primarily related to construction of the Sur de Texas and Villa de Reyes gas pipeline projects.

At December 31, 2017, the Company was committed to approximately $0.1 billion of capital expenditures for its Liquids Pipelines, primarily related to capital projects on operating pipelines.

At December 31, 2017, the Company was committed to approximately $0.4 billion of capital expenditures for its Energy business, primarily related to construction costs of the Napanee Generating Station.

At December 31, 2017, the Company was committed to approximately $0.1 billion of Corporate expenditures related to various information technology services agreements.

Contingencies

TransCanada is subject to laws and regulations governing environmental quality and pollution control. Asat December 31, 2017, the Company had accrued approximately $34 million (2016 – $39 million) related to operating facilities, which represents the present value of the estimated future amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur 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.

In March 2017, the U.S. Department of State issued a U.S. Presidential Permit authorizing construction of the U.S./Canada border crossing facilities of the Keystone XL pipeline. TransCanada discontinued its claim under Chapter 11 of the North American Free Trade Agreement and has also withdrawn the U.S. Constitutional challenge that was filed in June 2016 and arose from the November 2015 denial of our Presidential Permit application to construct the Keystone XL pipeline.

Guarantees

TransCanada and its partner on the Sur de Texas pipeline, IEnova, have jointly guaranteed the obligations for construction services during the construction of the pipeline.

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:

year ended December 31 (millions of Canadian $)	Term	2017 Potential Exposure[1]	2017 Carrying Value	2016 Potential Exposure[1]	2016 Carrying Value
Sur de Texas	ranging to 2020	**315**	**2**	805	53
Bruce Power	ranging to 2018	**88**	**1**	88	1
Other jointly owned entities	ranging to 2059	**104**	**13**	87	28
		507	**16**	980	82

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. Restructuring costs consist primarily of severance and expected future losses under lease commitments.

In 2015, the Company incurred $122 million before tax of corporate restructuring costs and recorded a provision of $87 million before tax related to planned severance costs in 2016 and 2017 and expected future losses under lease commitments. Of the total corporate restructuring charges of $209 million pre-tax, $157 million was recorded in Plant operating costs and other which was partially offset by $58 million that was recorded in Revenues in the Consolidated statement of income related to costs that were recoverable through regulatory and tolling structures. In addition, $44 million was recorded as a Regulatory asset as it is expected to be recovered through regulatory and tolling structures in future periods, and $8 million was capitalized to projects impacted by the corporate restructuring.

In 2016, an additional provision of $44 million before tax was recorded related to changes to the expected future losses under lease commitments. For the year ended December 31, 2016, $22 million was recorded in Plant operating costs and other in the Consolidated statement of income. In addition $22 million was recorded as a Regulatory asset on the Consolidated balance sheet at December 31, 2016 as this amount is expected to be recovered through regulatory and tolling structures in future periods.

In 2017, an additional provision of $6 million before tax was recorded related to changes to the expected future losses under lease commitments. For the year ended December 31, 2017, $3 million was recorded in Plant operating costs and other in the Consolidated statement of income. In addition $3 million was recorded as a Regulatory asset on the Consolidated balance sheet at December 31, 2017 as this amount is expected to be recovered through regulatory and tolling structures in future periods.

Cumulatively at December 31, 2017, the Company has incurred costs, net of recoverable amounts of $36 million for employee severance and $38 million for lease commitments under this initiative. The remaining employee severance provision at December 31, 2017 is expected to be settled in early 2018.

Changes in the restructuring liability were as follows:

(millions of Canadian $)	Employee Severance	Lease Commitments	Total
Restructuring liability as at December 31, 2015	60	27	87
Restructuring charges	—	44	44
Cash payments	(24)	(8)	(32)
Restructuring liability as at December 31, 2016	36	63	99
Restructuring charges	**—**	**6**	**6**
Cash payments	**(27)**	**(16)**	**(43)**
Restructuring Liability as at December 31, 2017	**9**	**53**	**62**

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 $)	**2017**	**2016**
ASSETS		
Current Assets		
Cash and cash equivalents	**41**	77
Accounts receivable	**63**	71
Inventories	**23**	25
Other	**11**	10
	138	183
Plant, Property and Equipment	**3,535**	3,685
Equity Investments	**917**	606
Goodwill	**490**	525
Intangible and Other Assets	**3**	1
	5,083	5,000
LIABILITIES		
Current Liabilities		
Accounts payable and other	**137**	80
Dividends payable	**1**	—
Accrued interest	**23**	21
Current portion of long-term debt	**88**	76
	249	177
Regulatory Liabilities	**34**	34
Other Long-Term Liabilities	**3**	4
Deferred Income Tax Liabilities	**13**	7
Long-Term Debt	**3,244**	2,827
	3,543	3,049

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 $)	2017	2016
Balance sheet		
Equity investments	**4,372**	4,964
Off-balance sheet		
Potential exposure to guarantees	**171**	163
Maximum exposure to loss	**4,543**	5,127

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of TransCanada Corporation

We consent to the use of our reports, each dated February 14, 2018, with respect to the consolidated financial statements and the effectiveness of internal control over financial reporting included in this annual report on Form 40-F.

We also consent to the incorporation by reference of such reports in TransCanada Corporation's:

- Registration Statements No. 333-5916, No. 333-8470, No. 333-9130, No. 333-151736 and No. 333-184074 on Form S-8;

- Registration Statements No. 33-13564 and No. 333-6132 on Form F-3; and,

- Registration Statements No. 333-151781, No. 333-161929, No. 333-208585, 333-214971 and 333-218711 on Form F-10.

/s/ KPMG LLP
Chartered Professional Accountants

February 15, 2018

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 15, 2018

/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 15, 2018

/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, 2017 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 15, 2018

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, 2017 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 15, 2018

Exhibit 99.1

TRANSCANADA CODE OF BUSINESS ETHICS
Making the Right Choices - Doing the Right Thing

Message from Russ Girling

At TransCanada, we pride ourselves on being a company that all of our stakeholders (whether they are customers, suppliers, investors, lenders, regulators, neighbors, or employees), can count on to make the right choices and do the right thing.

While our corporate values, namely Safety, Integrity, Responsibility and Collaboration form the foundation of how we do business, our Code of Business Ethics (COBE) goes one step further. COBE helps us put those values into practice in all of our daily decisions and activities. In this way, COBE helps to clarify what making the right choices and doing the right thing really means.

Making the right choices and doing the right thing is a serious matter. It's essential that you carefully read and ensure you understand the principles set out in COBE, and that you refer to it regularly. It will help you with guidance on ethical situations you face at work, and it will help you understand the type of behaviour expected of you. You are required to complete your COBE training and certification each year. Remember, all of us benefit by working for a company that makes the right choices and does the right thing. It takes all of us making the right choices and doing the right thing together to ensure TransCanada continues to be a company our stakeholders can count on.

Table of Contents

What Does Making the Right Choices and Doing the Right Thing Mean? 4

Making the Right Choices and Doing the Right Thing Requires that We Collaborate 7

- Compliance Organization 8
- Reporting Safety, Legal and Ethical Violations 9
- Ethics Help Line 10

Making the Right Choices and Doing the Right Thing Requires that We Be Safe 12

- Protecting Health, Safety and the Environment 13

Making the Right Choices and Doing the Right Thing Requires that We Act with Integrity 16

- Trading with Integrity 17
- Competing Fairly 18
- Giving Gifts, Invitations and Entertainment 19
- Political Contributions and Government Lobbying 21
- Accounting, Financial Reporting and Fraud Prevention 22
- Public Disclosure of Information 23
- Preventing Money Laundering and Terrorist Financing 24
- Avoiding Insider Trading and Tipping 25
- International Trade 26
- Complying with Regulatory Requirements 28
- Inter-Affiliate Interactions 29
- Avoiding Conflicts of Interest 30
- Dealing Fairly with Customers, Suppliers and other Stakeholders 33

Making the Right Choices and Doing the Right Thing Requires that We Act Responsibly 35

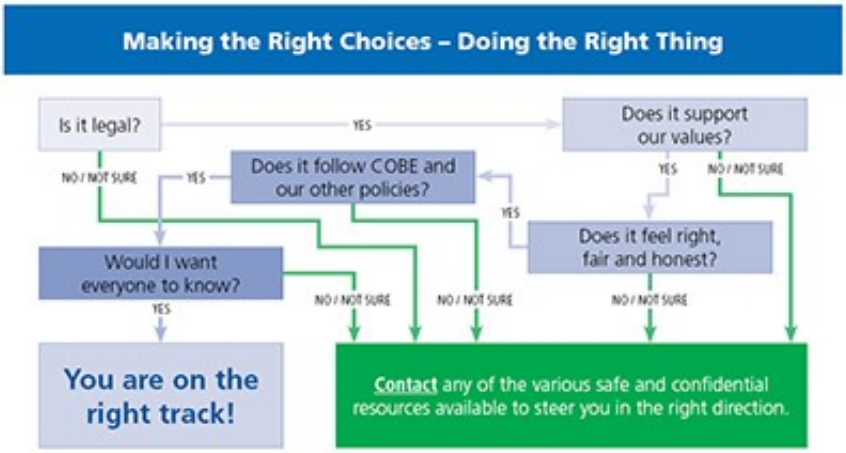
- Protecting Confidential Information 36
- Protecting and Respecting Intellectual Property Rights 37
- Managing and Maintaining the Security of Information 39
- Being Socially Responsible 40
- Being a Good Ambassador of TransCanada 41
- Protecting Individuals' Privacy 42
- Diversity and Employment Equity/Equal Opportunity 43
- Maintaining a Harassment, Violence and Weapons-Free Workplace 44

Glossary 46

What Does Making the Right Choices and Doing the Right Thing Mean?

At TransCanada, making the right choices and doing the right thing isn't just a catch-phrase - it's fundamental to how we do business. But what does it really mean to make the right choices and do the right thing? At a minimum, it means:

- We report all health, safety and environment related hazards, potential hazards, incidents, near hits, and unsafe acts.
- We comply with the applicable legal requirements and corporate policies that impact us in our daily work.
- We follow the principles set out in COBE.
- We report, through appropriate internal channels, any instances of actual or potential non-compliance with legal requirements or with COBE that we become aware of.
- We do not retaliate against anyone for the good-faith reporting of an incident or issue.
- We support others in making the right choices and doing the right thing.



Even if we try our best to make the right choices and do the right thing, there are times when the right thing isn't completely clear. It's at those times that we need to ask ourselves some fundamental questions. The above guide to making the right choices and doing the right thing is intended to help you identify the right path in those situations.

If in doubt, ask. Consequences of violations can be serious.

If you are ever unsure of how to make the right choices and do the right thing, it is always better to ask. The consequences of violating the law, COBE or any other corporate policy are very serious and can include discipline up to and including termination. In some circumstances, inappropriate conduct may also need to be reported to the authorities, and TransCanada could bring legal action against those involved. By asking before you act, you protect both yourself and the Company.

Does COBE apply to everyone?

COBE applies to all employees, directors and officers of TransCanada Corporation and its wholly-owned subsidiaries and operated entities in all countries in which TransCanada conducts business. Contingent Workforce Contractors (CWCs) and Independent Consultants must also comply with TransCanada's COBE or their own companies' equivalents to the extent such equivalents meet or exceed the standards set out in COBE.

We expect our vendors and suppliers to comply with equally high standards. If you are a CWC or Independent Consultant and are unsure of what standard you need to comply with, you should contact your employer or one of TransCanada's resources.

Are there situations where I don't have to comply with COBE?

Only the Chief Compliance Officer has the authority to waive any individual's compliance with COBE. Waivers for executive officers and Board members must be approved by the Board of Directors (or a committee of the Board) and disclosed, if required.

TransCanada employees and officers are required to complete annual COBE training; you will be required, in conjunction with that training, to certify that you understand and are in compliance with all legal requirements, corporate policies and COBE.

What does making the right choices and doing the right thing require?

Making the right choices and doing the right thing requires that we:

- Work safely
- Act with integrity
- Act responsibly
- Collaborate

Kristine Delkus
Executive Vice-President, Stakeholder and Technical Services and General Counsel
Chief Compliance Officer

TransCanada is committed to ethical and lawful business conduct - making the right choices and doing the right thing every time.

Making the Right Choices and Doing the Right Thing Requires that We Collaborate

We work together as one company to make the right choices and do the right thing. TransCanada has set up an ethics and compliance organization that works across TransCanada's various departments, business lines, functions and regions to help ensure we make the right choices and do the right thing together.

Compliance Organization

We look to the ethics and compliance organization and the resources that have been put in place to help us to make the right choices and do the right thing.

The various members of the ethics and compliance organization are available to work with you and support you in making the right choices and doing the right thing in your day-to-day work. The following is a list of the different members of TransCanada's compliance organization.

- Audit Committee of Board of Directors
- Chief Compliance Officer
- Compliance Committee
- Compliance Coordinators
- Corporate Compliance Department
- Human Resources and Harassment Investigation Coordinator
- Internal Audit

Leaders

TransCanada's leaders play a special role in ensuring we all make the right choices and do the right thing together.

If you are a leader, you have the following responsibilities in addition to complying with the principles set out in COBE:

- Inspire your Personnel to act ethically by setting an ethical tone within your team.
- Reinforce the importance of making the right choices and doing the right thing relative to other corporate objectives (for example, profits and cost management).
- Set an example by modeling exemplary ethical business conduct.
- Create a safe environment in which individuals are encouraged to speak up if they are aware of or suspect a legal or ethical violation through both your words and your actions.
- Accept reports of violations that individuals may bring to you, and understand your obligation to report these issues, as appropriate, to your Compliance Coordinator, the Corporate Compliance Department, Internal Audit, the Harassment Investigation Coordinator, Privacy Officer, or the Ethics Help Line**.**
- Ensure that your direct reports understand and act in accordance with all legal and ethical requirements that impact them in their jobs, that they know how to report actual or potential non-compliance with the law or COBE or to ask questions regarding ethical or legal matters, and that they complete all required ethics and compliance-related training.
- Assist and support individuals who are unsure how to make the right choices and do the right thing.
- Work with Human Resources, your Compliance Coordinator, the Corporate Compliance Department and Internal Audit to ensure violations of legal requirements or COBE by your direct reports are addressed appropriately (including discipline as appropriate).
- Work with your Compliance Coordinator and the Corporate Compliance Department to reward individuals who have demonstrated exceptional positive ethical behaviour or actions that reduce the risk of legal violations.

Reporting Safety, Legal and Ethical Violations

We report any actual or potential non-compliance with TransCanada's COBE or any legal obligation, so it can be addressed as appropriate. We do so with confidence that our confidentiality and identity will be protected to the greatest extent possible and that retaliation for Good Faith Reporting is prohibited.

How do I report an issue or seek guidance?

You are required to report any actual or suspected violation of the law or of COBE and all health, safety and environment related hazards, potential hazards, incidents, near hits, and unsafe acts of which you may become aware. We take every report seriously and provide immunity from disciplinary action for Good Faith Reporting of incidents and issues.

Resources

To report an issue, or if you would like guidance on how to make the right choices and do the right thing in a particular situation, the following resources are available to you:

- Your leader
- Your Human Resources Consultant
- Your Compliance Coordinator
- Corporate Compliance Department
- Internal Audit
- Law Department
- Privacy Officer
- Harassment Investigation Coordinator
- Safety Personnel
- TransCanada's EHSM Incident Management System

To report an ethical violation when you don't feel comfortable contacting the resources above, you can remain anonymous by contacting the Ethics Help Line, which is operated by an independent third-party.

Ethics Help Line

Canada / U.S. 1.888.920.2042
Mexico001.800.840.7907
www.transcanada.com/ethics

The Ethics Help Line is operated by an independent third party service provider. The service provider does not have caller ID and does not provide TransCanada with information on your identity unless you expressly give the service provider your name. No attempt will be made to determine your identity if you choose not to provide it.

All calls to the Ethics Help Line are free of charge, and can be made in English, French or Spanish 24 hours a day, seven days a week, 365 days a year.

You may use the Ethics Help Line either to report any actual or suspected issues or to ask questions. When you make a report through the Ethics Help Line, you can choose whether or not you want to remain anonymous. If you choose to remain anonymous you will be given a code known as a “report key” which you can use to call back for updates or to provide additional details. In this way the Company can provide you with information on how your report is being managed, or get more information from you without discovering your identity.

Reports made to the Ethics Help Line are forwarded to a limited number of individuals within TransCanada. Internal Audit is responsible for investigating issues raised and ensuring all calls are addressed appropriately. Particularly serious issues are reported to the Audit Committee of the Board of Directors.

If the issue raises an immediate threat to safety or security, you should contact Corporate Security, local police or other emergency services as appropriate.

All reports are taken seriously

Regardless of the means used to report, you can feel confident that the report will be taken seriously and that it will be investigated and addressed as appropriate, in accordance with TransCanada’s Procedure for the Investigation, Management and Reporting of Instances of Non-Compliance. Harassment issues are investigated by the Harassment Investigation Coordinator in accordance with the Harassment-Free Workplace Policy.

Confidentiality/anonymity

Your confidentiality and your identity (if known) will also be protected to the greatest extent possible. The information you provide will be shared only with those who need to know in order to ensure the issue is properly investigated and addressed.

Non-retaliation

We support and encourage you to report suspected instances of potential non-compliance with applicable laws, regulations and authorizations, as well as hazards, potential hazards, incidents involving health and safety or the environment, and near hits. We take every report seriously, investigate each report to identify facts, and make improvements to our practices and procedures when warranted. All Personnel making reports in good faith will be protected. Good Faith Reporting is intended to remove protection for Personnel making intentionally false or malicious reports, or who seek to exempt their own negligence or willful misconduct by the act of making a report. We ensure immunity from disciplinary action or retaliation for Personnel for the Good Faith Reporting of such concerns. Reports can be made to management, a Compliance Coordinator, or anonymously to the Ethics Help Line.

Paul Miller
Executive Vice-President and President, Liquids Pipelines

We count on everyone to report issues. Retaliation for Good Faith Reporting is not tolerated.

Participation in investigations and audits

Personnel, including directors and officers are required to participate in investigations and audits if, and as, requested.

QUESTION: I suspect one of my colleagues has violated part of COBE, but I'm not sure my suspicions are correct. I'm concerned I'll be labeled a tattle-tale (or worse) if I report it. What should I do?

ANSWER: If you suspect misconduct, you should report it so it can be investigated. If it turns out not to be an issue, there will be no harm done. Violations of the law or COBE that are not reported, however, cannot be addressed, and that can seriously undermine the Company. If that happens, we all suffer. If you report the issue, your confidentiality and identity will also be protected and if any retaliation is found to occur, it will be taken very seriously.

Making the Right Choices and Doing the Right Thing Requires that We Be Safe

Our goal is to make safety a high-priority value that drives changes in behavior, attitude and beliefs across the entire organization. In order to make this culture of safety a reality, we have made these commitments:

- We will work towards an incident free workplace because we believe that **Zero is Real**.
- We will learn the nine **Life Saving Rules** and follow the, always.
- We will **SHARE our observations** of safe and unsafe acts with our colleagues whether they occur at work, home or play.

Protecting Health, Safety and the Environment

We consider the impact of our actions on stakeholders, the environment and the communities in which we operate. We act responsibly to protect the health and safety of our workers, our neighbours and the public, and we act as responsible stewards of the environment.

Whether you work in a field location or in an office setting, you must always ensure that you comply with all health, safety and environment related legal requirements, as well as TransCanada's corporate policies.

In addition, TransCanada's Life Saving Rules guide the way we work and help us hold each other accountable to the highest possible safety standards. They were created to highlight the high-risk activities that are part of the work we do every day and emphasize the importance of following the risk control measures we have in place to manage them.

We will:

1. Drive safely and without distraction
2. Use the appropriate Personal Protective Equipment
3. Conduct a pre Job Safety Analysis (JSA)
4. Work with a valid work permit when required
5. Obtain authorization before entering a confined space
6. Verify isolation before work begins
7. Protect ourselves against a fall when working at heights
8. Follow prescribed lift plans and techniques
9. Control excavations and ground disturbances

Committing to the Life Saving Rules means meeting our goal of everyone going home safe from our offices, facilities and project sites, every day. Nothing is more important.

All injuries and environmental damage are preventable if we apply a 24/7 approach to health, safety and environmental protection. Policies, programs and standards for health, safety and environment can be found on Infocus > Departments:

- Environment
- Health & Industrial Hygiene
- Safety

We report all health, safety and environment related hazards, potential hazards, incidents, near hits, and unsafe acts. We take every report seriously, investigate to identify facts and ensure immunity from disciplinary action for the good faith reporting of all incidents and issues.

QUESTION: I'm working on a big project and it's very important to the Company that it be completed on-time and on-budget. I'm concerned that I might be injured if I rush my work, but I'm feeling a lot of pressure to do so. What should I do?

ANSWER: You should never compromise your or anyone else's safety. If someone is pressuring you to do so, you should report the issue.

Wendy Hanrahan
Executive Vice-President, Corporate Services

We believe that Zero is Real. This means that everyone has a responsibility to identify hazards in their workplace to ensure their safety and the safety of their coworkers.

Being Fit for Work

We do not compromise our ability to do our jobs or the safety of others through the use of intoxicants including drugs, alcohol or medications.

Given the nature of TransCanada's business, it is essential that all workers be fit to perform their jobs. The use of intoxicants can impair your judgment and productivity, and can lead to serious accidents and health and safety concerns - not only for yourself, but also for your coworkers and the public.

You must ensure you understand and comply with TransCanada's internal policies concerning the use of alcohol and drugs, and ensure you are fit to perform your job. For more information, please consult the Alcohol and Drug (Employee) Policy and the Contractor Alcohol and Drug Policy.

Making the Right Choices and Doing the Right Thing Requires that We Act with Integrity

We act ethically and with integrity and we comply with the legal requirements and corporate policies applicable to us in our jobs. We make the right choices and do the right thing, even when others don't and even when making the wrong choices and doing the wrong thing seems easier or better for the bottom line.

Trading with Integrity

We engage only in transactions that have a legitimate business purpose, and we do not interfere with the normal functioning of the markets in which we operate and transact. We also report transactions in accordance with all legal requirements.

We conduct business in a way that promotes a fair, efficient and openly competitive operation of markets in which we participate and which complies with market manipulation laws. Market manipulation laws prohibit any actions intended to interfere with the normal functioning of markets through fraud or deception of others, or increases or decreases in capacity or prices in contravention of market manipulation laws or other local market rules.

Some examples of illegal market manipulation include artificially increasing or decreasing generation or transmission capacity, making especially high or low bids that may be prohibited by market rules, and entering into both purchase and sale transactions at the same time (so there is no net change in beneficial ownership), in order to falsely increase the perception of trading volumes (known as “wash trading”). It may also include intentionally losing money on transactions that impact prices in order to obtain the benefit of those prices in other transactions.

While the previous examples are intended as a general discussion, market rules and obligations vary by jurisdiction. You must be knowledgeable about the particular rules applicable to the market(s) in which you trade and be careful never to enter transactions that are illegal under local laws or other local market rules, or to otherwise interfere in the normal functioning of the markets.

You should also always ensure that you accurately report transactions so TransCanada can meet its legal reporting obligations.

Competing Fairly

We compete vigorously and fairly, based on price, quality and service and do not interfere with our customers' or other market participants' ability to do the same**.**

A competitive marketplace in the energy and transmission services that TransCanada provides helps ensure fair prices and customer choice and, in turn, results in the industry as a whole providing more effective, better service. We believe in vigorous, fair competition and comply with all laws designed to protect the ability of companies to compete freely.

In particular, you should never engage in any illegal acts that are intended to, or that are likely to have the effect of, reducing competition. The most serious and most common of such acts is collusion, which means entering into an agreement (usually with one or more competitors) to reduce competition. Examples of such agreements include agreements to:

- Fix prices
- Decrease capacity or volume available to customers
- Allocate customers or markets among competitors
- Boycott certain customers or suppliers

Even sharing competitively sensitive information (such as information regarding prices, capacity, volume, customers or markets) with competitors can be seen as evidence of collusion. As such, you need to be very careful whenever you have contact with competitors (whether in trade association meetings, at conferences, through participation in benchmarking groups or in negotiating or otherwise dealing with actual or potential joint venture partners who are also TransCanada competitors) to avoid sharing competitively sensitive information. You must never enter into an agreement to reduce competition, or that is likely to have that effect.

Competition/antitrust laws must also be kept in mind when you are involved in joint purchasing arrangements, negotiating acquisitions or divestitures, joint venture arrangements and the like, particularly when the parties are TransCanada competitors.

QUESTION: While at a trade association meeting recently, a few competitors I was sitting with at dinner started talking about their pricing. I knew it wasn't appropriate, so I didn't say anything. Did I do the right thing?

ANSWER: While you were right not to participate in the discussion, when in such a situation, it's a good idea to take the further step of making clear to everyone that the discussion is inappropriate and that you will not participate. If the inappropriate discussion continues, you should physically remove yourself from the situation. You should also document what happened and report the matter. This will help to protect you and TransCanada in case anyone ever points to the fact that you were part of a group in which an inappropriate discussion took place.

Giving Gifts, Invitations and Entertainment

We do not provide either private parties or government officials (including employees of state-owned companies, members of international organizations, political parties and candidates for office) with payments, kickbacks, gifts, or anything else of value (including benefits such as entertainment, charitable contributions or employment opportunities) for the purpose of improperly influencing such parties' actions or decisions in favour of TransCanada. Even if the intent is not to influence, you should not provide a payment or benefit to any third party if it could appear to be improper.

We always conduct our business in a legal and ethical manner. Part of behaving ethically means that we do not participate in any corrupt activities and maintain compliance with all applicable anti-bribery and anti-corruption laws and regulations of each jurisdiction in which we conduct business. Corruption in both business and government is a problem since it prevents fair and open competition based on merit.

We should always be prudent in offering gifts, entertainment or anything else of value (including, but not limited to, golf games, meals, or tickets to sporting or other similar events) to anyone or any organization that is a competitor or that TransCanada does or seeks to do business with, or that TransCanada requires consent or approval from. While giving gifts can help to build and maintain strong business relationships, depending on the nature of, and the context in which, such gifts/entertainment/benefits are given, they can also cloud one's judgement or be seen to improperly influence decisions.

The following considerations should be taken into account whenever you are faced with the prospect of giving a gift or invitation or when providing entertainment or another type of benefit:

- We should never give, offer, promise, or approve a gift/entertainment/benefit that could violate anti-bribery/anti-corruption legislation. Gifts/entertainment/benefits given to government officials and employees of government or government-owned entities are particularly sensitive. For more information on the provision of gifts to government officials, please refer to Gifts, Meals, Entertainment and Travel for Government Officials Standard.
- We should never give a gift/entertainment/benefit in exchange for a business advantage (including entering into a contract or other business relationship, obtaining or giving more favourable business terms, or obtaining consent or approval), or where giving the gift/entertainment/benefit could even create the appearance that it might be for such purpose.
- We should never give cash, cash equivalents, shares, or other securities.
- We should never give a gift/entertainment/benefit that could be considered offensive or in poor taste, or that could damage TransCanada's reputation.

Since TransCanada can be held responsible for improper payments and benefits provided by agents, CWCs, suppliers and other third parties acting on TransCanada's behalf, we must also do our best to ensure that we only deal with legitimate, reputable parties, and that they understand their obligation to not provide such improper payments or benefits in connection with the business they do for TransCanada. We follow the processes that TransCanada has in place to review third parties' bribery and corruption risk.

In addition, we must ensure that legitimate expenditures, including their nature and purpose, are accurately reported, so there is no question of whether they were made for an improper purpose.

For more information, please refer to the Avoiding Bribery and Corruption Policy, Enhanced Community Support Standard, and the Gift, Meals, Entertainment and Travel for Government Officials Standard.

Political Contributions and Government Lobbying

We respect the political process, and only make political contributions and engage in lobbying activities that are legal and transparent.

Laws concerning political contributions and government lobbying are aimed at preventing corruption in government and at ensuring the proper functioning of the political process. The rules can be complex and vary greatly from jurisdiction to jurisdiction. In some jurisdictions we are not allowed to make political donations at all. In other jurisdictions, the amount of political donations and the ways in which they may be made are restricted, and they often require registration of lobbyists and reporting of certain contacts with government officials.

TransCanada's Government Relations group manages all of TransCanada's political donations. Lobbying-related activities are also managed by Government Relations for federal, state or provincial governments, and Community Relations manages lobbying activities for municipal and local governments. To ensure we comply with all legal requirements, you must seek approval from the appropriate department before engaging in these activities on behalf of TransCanada.

Refer to the Avoiding Bribery and Corruption Policy and the Political Activities and Contributions Policy for more information on payments to government officials.

QUESTION: I am very politically active. Is that allowed?

ANSWER: TransCanada encourages you to participate in the political process as an individual, in accordance with your own political views and the laws and regulations governing this activity. In doing so, however, you may not use TransCanada's name, nor indicate that you represent TransCanada, unless you have been authorized to do so.

Accounting, Financial Reporting and Fraud Prevention

We are open and forthright in reporting our financial condition to investors and lenders, as well as in reporting our costs to customers and regulators. We ensure that our accounting and financial records and reporting are fair, accurate, understandable and complete, and we do not falsify financial documents or records, or misstate or misrepresent the nature of costs or expenditures.

In order to make informed investment decisions, our investors need to know that our accounting records and financial reporting are accurate and complete. Our lenders similarly require that we disclose certain information to them regarding the Company's financial condition. In addition, TransCanada's customers and regulators rely on the accuracy of our accounting records to ensure that pipeline tolls are calculated in a fair and transparent manner.

You must ensure all transactions that you engage in, or that you approve, whether under a TransCanada contract or as an individual business expense, are reported and that the reporting is accurate, complete and complies with all applicable accounting and legal requirements. You must also follow all relevant corporate policies and other requirements respecting the transaction (for example, spending limits and obtaining of approvals).

You should never engage in "off the record" or other transactions or accounts that do not fully and accurately state the nature and amount of specific transactions.

You must also never falsify any invoice, expenditure, time sheet or other document related to a Company cost or revenue. Doing so constitutes fraud and is prohibited. For more information, please see the Avoiding Bribery and Corruption Policy and TransCanada's Policies on Risk Management and Financial Reporting which can be found on the Corporate Policies website.

Public Disclosure of Information

We ensure that public statements regarding the Company are provided in a timely manner, are fair, accurate and complete, comply with legal requirements and corporate policies, and preserve and protect TransCanada's reputation and brand.

In order to ensure that all potential investors receive information that could be material to a decision to buy or sell TransCanada shares or other securities, TransCanada must disclose material information regarding the Company publicly and in a timely manner.

In addition, we need to ensure that information released to the media or the public regarding the Company is accurate and fairly stated and that a clear and consistent message is provided to our various stakeholders.

TransCanada has policies and procedures regarding proper public disclosure of information, and you should always use those prescribed channels. If you receive an inquiry from an external source you should direct it to the appropriate Company representative for response.

The groups managing these inquiries include:

Media/Charitable Organizations /Elected Officials	u	Government Relations, Communications and Community Relations
Investors/ Lenders/ Analysts	u	Investor Relations and Corporate Communications
Regulatory Agencies	u	Law Department
Employment Related	u	Human Resources

In the age of social media, it is easy to broadly and publicly communicate information. We need to be particularly aware of our obligations to disclose Company information only in accordance with legal and internal requirements. For more information, please see TransCanada's Public Disclosure Policy and the Communications Policy.

Don Marchand
Executive Vice-President, and Chief Financial Officer

> *I can't stress enough how important accurate, timely and complete financial reporting and public disclosure is - it's what gives us access to the financial markets and builds with investors and lenders confidence and trust in our Company.*

Preventing Money Laundering and Terrorist Financing

We expect our customers and suppliers to be vigilant in ensuring the payments we make and the methods of payment we use are legitimate and legal.

Even if we make the right choices and do the right thing, there could be instances in which our customers and suppliers do not. Laws concerning money laundering and terrorist financing are in place to deter criminal and terrorist activities of those with whom we might do business.

In order to ensure compliance with these laws, you, when acting on behalf of TransCanada, must exercise care before agreeing to do business with a third party. You should ensure it is a legitimate, reputable business and you must recognize and report any suspicious payments or transactions. Third parties are reviewed as part of Supply Chain's qualification process.

Examples of such suspicious payments or transactions include: any request by a third party to have a payment deposited into a personal rather than a business account; transactions with entities other than those involved in the underlying contract or business deal; or payments or other transactions involving a country other than that in which the parties to the contract or business deal are located. Payments of cash, unusual financing arrangements, fictitious invoices or other efforts by a third party to conceal the true purpose of a payment or transaction also raise concerns.

DID YOU KNOW…
Ignoring the signs that a transaction or payment initiated by a third party is not legitimate can result in TransCanada being found complicit in any illegal activity that may be associated with the transaction, even if the Company did not expressly authorize it or even know about it.

Avoiding Insider Trading and Tipping

We do not use material non-public information to trade in shares or other securities, or provide such information to others for that purpose.

We all have access to non-public information regarding TransCanada, and sometimes we also have access to non-public information regarding customers, suppliers and other business partners.

To the extent non-public information that you are aware of could be material to a decision to buy or sell shares in TransCanada or another company (for example, if the information relates to a pending merger or acquisition, a new project or project approval, or financial results that have not yet been made public), you and your immediate family members are not permitted to use that information to trade in the relevant company's shares or other securities.

You must also be careful not to provide that information to anyone else who might use it for that purpose.

To the extent that you are a Company insider, you have the additional obligation not to trade in TransCanada shares and other securities during black-out periods. For more information, please see the Trading Policy for Employees and Insiders.

International Trade

When engaging in international business, we comply with all international trade legislative requirements, as well as all customs and taxation requirements.

International trade laws prohibit or restrict trade with certain countries that are subject to embargoes or sanctions, as well as with certain individuals and organizations (e.g. entities that have ties to actual or suspected terrorists or drug traffickers). These laws also prohibit or restrict imports and exports of certain types of goods, information and technologies - particularly those that could be used in weapons applications, but also including certain chemicals and commodities, such as oil and gas liquids. They also prohibit or restrict certain exports where the product will ultimately be put to military or weapons-related uses.

These laws also often impose stringent reporting obligations. As a transmission provider, TransCanada is even responsible for certain import/export related reporting in respect of commodities that it transports across an international border through its pipeline, even though it does not own or control the transported commodities.

In addition, TransCanada has customs compliance obligations in connection with all cross-border transactions. TransCanada can only operate as an authorized importer/exporter in the three jurisdictions in which it operates; however, this does not preclude the Company from procuring products from the global market. In these instances special attention must be paid to the terms of the individual agreements.

Whether the products and the goods are sold or transferred, all goods that cross international borders must be formally declared to the appropriate customs agency and may require prior approval and reporting to other government agencies in the country of export as well as in the country of destination where the commercial importation will occur. Consideration should be given to the necessary import and export requirements when considering contracting strategies.
Some examples of these transactions include inter-office packages, inter-company inventory transfers and sales, gifts from vendors, materials for conferences or trade shows, and all cross-border movements of material, information or technology.

Before engaging in any international transaction or sending electronic or other information or technology to another country (even to others within TransCanada who are located in a different country than you), TransCanada must ensure it is legally permitted, considering the nature of the goods, information or technology, the counterparty with which you are dealing, the country in which the counterparty is located, and the use of the goods, information or technology. TransCanada must also ensure that all applicable licensing requirements are met, and that it complies with all reporting and customs obligations. This includes ensuring the goods shipped are valued correctly for customs purposes.

For more information, please contact TransCanada's Logistics Customer Service team in Supply Chain for day-to-day import/export customs activities or any inquiries related to freight and transportation, and in respect of trade compliance matters please contact TransCanada's Customs Management team in Corporate Compliance.

DID YOU KNOW…
Even if TransCanada does not have ownership of a product it has purchased when it crosses a border (e.g. because it takes ownership, or title, on delivery), it may nevertheless be responsible for

import and/or export compliance based on certain terms of the purchase contract. It is important to ensure the contract does not contain terms that result in TransCanada inadvertently taking on these obligations.

Complying with Regulatory Requirements

We are committed to meeting our obligations under all regulations and tariffs.

As a regulated company, TransCanada is subject to many regulatory requirements, including those of the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Comisión Nacional de Hidrocarburos, and the North American Energy Reliability Corporation (NERC), among others. In addition, TransCanada's transmission providers are subject to tariffs that we must comply with.

Although it is impossible to list all of these requirements in COBE, you must ensure you are familiar with the specific requirements applicable to you in your job. These can include reporting requirements and compliance with technical or other standards.

To the extent the requirements of more than one jurisdiction apply, you must use the highest of the various standards.

QUESTION: I'm not a lawyer. How can I be expected to know all of the laws that might apply to my job or even be able to understand them?

ANSWER: While you are not expected to know all of the ins and outs of every law, you do need to have a basic understanding of the different areas of law that impact you in your job, so that you can spot potential issues and seek help from an expert. Your leaders and the ethics and compliance organization (particularly your Compliance Coordinator, the Corporate Compliance Department and the Law Department) are also available to help you if you have questions about your legal obligations and are available to provide training on legal requirements that may be applicable to your team.

Inter-Affiliate Interactions

As a transmission provider, TransCanada is subject to Canadian Codes of Conduct in Canada and the Standards of Conduct in the U.S (Inter-affiliate Codes/Standards of Conduct). These Codes/Standards of Conduct are intended to ensure that our non-regulated affiliates do not receive an unfair advantage over other customers, whether as a result of discriminatory treatment or the sharing of information, Personnel or resources. The Canadian Codes also prohibit the cross-subsidization of our non-regulated affiliates at the expense of our transmission customers.

In order to ensure compliance with the Inter-Affiliate Codes/Standards of Conduct, you must observe the following rules in your day-to-day activities:

- Regulated transmission providers may not give undue preference to any customer, whether it is an affiliated TransCanada entity or not - all customers must be treated equally.
- Regulated Personnel must function independently of non-regulated Personnel (e.g. they cannot perform the same jobs or report to the same leaders).
- Regulated and shared Personnel must not share, or act as a conduit for the sharing of regulated information* with non-regulated Personnel.
- Any violations of the Inter-Affiliate Codes/Standards of Conduct must be reported to the Corporate Compliance Department, since TransCanada is legally required to either publicly post such information on its web site or report it to our regulators.
- Non-regulated entities must pay their fair share of any costs incurred by our regulated transmission providers, so as not to burden our transmission customers with costs our non-regulated entities benefit from.

*Regulated information (which may not be shared with non-regulated Personnel) includes commercial, financial, strategic, planning, operational and customer information of our transmission providers. For more information, please see TransCanada's Inter-Affiliate Codes/Standards of Conduct.

Karl Johannson
Executive Vice-President and President, Natural Gas Pipelines

> *Reporting of instances of actual or potential non-compliance is so important since it's really the only way we can find out about underlying problems and fix them. It allows us to learn from our mistakes and continually get better at making the right choices and doing the right thing.*

Avoiding Conflicts of Interest

We act in TransCanada's best interests, avoiding situations that could place us in a conflict, or even create a perception of conflict and we report such situations if and when they arise.

To the extent our personal interests conflict or have the potential to conflict with TransCanada's, our ability to honour this obligation and to make objective decisions on behalf of the Company are compromised.

It is for this reason that you must avoid situations that can result in potential conflicts. If you ever find yourself in a situation that creates a potential conflict, you should report it. You should not participate in any decision or action in which there is a real or perceived conflict. You should always avoid any situation where you would improperly benefit, or appear to improperly benefit, from knowledge acquired while working at TransCanada.

The following are some examples of situations that create potential conflicts of interest.

Accepting gifts, invitations and entertainment from Suppliers

Accepting gifts or invitations from suppliers or potential suppliers ("Suppliers") can affect the way TransCanada is perceived and can run counter to our business objectives and values. We all have an obligation to conduct ourselves in a fair and impartial fashion in all business dealings with the supplier community.

During the normal course of business, Personnel may accept invitations from suppliers for meetings over meals and beverages.

Careful consideration must be taken when a supplier extends an invitation to a social event or offers a gift. Personnel must consider the following:

- Invitations to events and trips, including but not limited to sporting events, golf rounds, skiing or fishing trips, and other special events should not be accepted, except as provided for below. Attendance at such events may provide an opportunity to network with suppliers, but could be mistaken as a sign of a preferential relationship.
- Invitations to events which may be considered lavish in nature should not be accepted.
- Frequency of attendance at events with the same supplier should be carefully considered and discussed with your leader prior to attendance to avoid the perception of any preferential treatment.
- Occasional promotional gifts (such as pens, coffee mugs, calendars) may be accepted as a customary business courtesy, provided that the frequency of gift must not exceed 4 times per calendar year and a value of $50 per gift or total more than $100 in aggregate for the calendar year.
- Invitations to industry events such as conferences and conventions have not changed and continue to require leader approval.

There will be circumstances where exceptions to these guidelines make business sense. In these cases, written approval from your Senior Vice-President or Vice-President or designate is required.

Outside business activities and outside directorships

TransCanada employees and officers may not engage in outside business activities, (e.g. as a consultant, employee, or director), that are in conflict with or detrimental to the interests of TransCanada. Where you may be involved in these activities, consider whether the activity creates, or could be perceived to create, a conflict of interest.

Types of prohibited business activities may include:

- Owning, controlling or directing a material financial interest (greater than one per cent) in a competitor, or in a vendor, supplier, customer or other business which does or seeks to do business with TransCanada
- Being involved in a business that competes with TransCanada or that does or seeks to do business with TransCanada
- Outside business activities that interfere with your day-to-day responsibilities at TransCanada. Unless specifically approved by your leader, you are expected to spend your full time and attention performing your job during your hours of work
- An outside business activity that requires you to violate your confidentiality or other obligations to TransCanada
- An outside business activity that would be detrimental to TransCanada's reputation
- Any outside directorship including a charitable or non-profit organization, sporting organization, or school board, if that activity is detrimental to TransCanada

In cases where an outside business activity or directorship position on a board is not in conflict with TransCanada's business as described in the list above, the activity or position must still be declared to and approved by the Corporate Secretarial group prior to acceptance.

Contact the Corporate Secretarial group for more information.

If you are uncertain whether an activity may create a conflict of interest, please contact the Corporate Compliance Department for guidance.

Executive leadership team - other business activities

In addition to the conditions set out in the above section, prior to serving in any capacity in an unaffiliated organization, the Chief Executive Officer and any member of the Executive Leadership Team must obtain the consent of the Governance Committee of the Board of Directors.

Directors' independence

In order to maintain their independence and to ensure that no relationships exist that may violate applicable corporate, securities and competition laws, all directors of TransCanada are required to have their independence assessed annually and also periodically in the event of a material change in their respective primary employment status or in the event they wish to join another board of directors, whether private or public. All candidates to TransCanada's board of directors are required to meet these independence standards, legal requirements and other standards before they can be formally considered for appointment. A director is required to declare any material interest that he or she may have in a material contract or transaction and recuse himself or herself from related deliberations and approval.

Corporate opportunities

You may not take personal advantage of a business opportunity that you discover through the use of Company assets, property, information, or your position with TransCanada, or use Company assets, property, information, or your position with TransCanada for personal gain or to compete with TransCanada.

Political office, appointments to boards or tribunals

TransCanada employees and officers may not serve in a political office or on an administrative board or tribunal, if that office, board or tribunal has or may have decision-making authority in respect of any aspect of TransCanada's business (such as the approval or projects or the issuing of permits).

Personal relationship disclosures

TransCanada Personnel (including CWCs) may not be in a Direct or Indirect Reporting relationship with or otherwise involved in hiring, delegating work or making compensation decisions with respect to someone with whom you have a Family or Other Significant Personal Relationship. Some examples of such relationships include, but are not limited to, a spouse (including common-law and same gender spouses), parent, grandparent, child, grandchild, sibling, aunt or uncle, niece or nephew, cousin, or an individual who has acquired such a relationship through marriage/common-law, or any "step", "common-law" or "in-law" variations of these relationships. This applies to all current and new Personnel, student employees, and CWCs.

These provisions also apply to any position moves/promotions within the Company and require that a personal relationship disclosure be made and approved in advance of such a move/promotion.

The onus is on all Personnel (including CWCs) to notify Corporate Compliance if they become aware of a Family or Other Significant Personal Relationship within a Direct or Indirect Reporting relationship at TransCanada.

Corporate Compliance must review the hiring of any new Personnel where there is a Family or Other Significant Personal Relationship (as described in the paragraph above) with existing TransCanada Personnel.

Review the Personal Relationship Disclosure Policy for more information or contact the Corporate Compliance Department.

CWC and Independent Consultants

CWCs and Independent Consultants must not directly or indirectly offer employment to TransCanada employees during the currency of their contract and for a reasonable time after their contract ends. Further, CWCs and Independent Consultants must not offer preferential pricing or benefits to individual TransCanada employees.

Dealing Fairly with Customers, Suppliers and Other Stakeholders

We are fair and honest in our dealings with customers, suppliers and other stakeholders and we honour our obligations and commitments to them.

Treating customers, suppliers and other stakeholders fairly requires that you enter into business relationships based on merit and objective criteria, such as price, quality and service. It also requires that you are honest and forthright when dealing with others (never omitting important facts, manipulating another person or situation, or misrepresenting yourself or TransCanada), and that you honour TransCanada's contractual, regulatory and other commitments.

You should never make business decisions on behalf of TransCanada based on personal relationships, unfair bias or the potential for personal gain.

Dealing fairly with competitors

You must also ensure that you use only legitimate means (such as searches of public information) to obtain competitive intelligence. You must never use deceit or misrepresent yourself to obtain such information, and you should never take advantage of information you receive in error (for example, emails, faxes or documents someone sent you in error, or documents left in a meeting room or in a public place).

Use of company name for personal gain

Finally, you must never use the Company's name or purchasing power or your employment status to obtain personal discounts or rebates from vendors, unless those discounts or rebates are available to all employees.

Francois Poirier
Executive Vice-President, Strategy and Corporate Development

> *If you are uncertain as to whether a personal interest conflicts with, or has the potential to conflict with TransCanada's interests, ask for guidance from one of TransCanada's internal resources or from the Ethics Help Line.*

QUESTION: I want to hire someone who I know has a family member already working for TransCanada. Is that allowed?

ANSWER: Yes, it is acceptable to hire a person (Employees and CWCs) that has a family member already working for TransCanada provided the new hire is not in a Direct or Indirect Reporting relationship with their family member. The onus is on all Personnel to notify Corporate Compliance when they become aware of a Family or Other Significant Personal Relationship where there is a Direct or Indirect Reporting relationship within the Company.

QUESTION: I own units of a mutual fund that invests in shares of one of our suppliers. Is that a problem?

ANSWER: If your investment in the supplier is through a mutual fund, it is unlikely that you would own more than one per cent of the stock of the supplier. Because of the indirect nature of the investment, it is also less of a concern than if you owned the shares directly. Your ownership of mutual fund units is not a problem.

QUESTION: I have been invited by a supplier to attend the rodeo at the Calgary Stampede. Can I accept the invitation and attend the event?

ANSWER: All TransCanada Personnel must ensure they are acting in a manner which is fair and impartial to our supplier community and which does not create a real or perceived conflict of interest with those with whom we do business. As such, attendance at this event would only be acceptable if the supplier had invited customers from other companies as well. Prior written approval must be received from your Vice-President to ensure that the number of TransCanada Personnel and other customers at the event is appropriate.

QUESTION: I have been invited to a movie event by a company that is a supplier to TransCanada or has the potential to become a supplier to TransCanada that I have a relationship with. Can I attend this event?

ANSWER: Employees can accept invitations from suppliers/potential suppliers for events where multiple clients are in attendance provided they have received approval from their Vice-President prior to attending.

QUESTION: One of TransCanada's existing auto leasing suppliers has invited me to attend their annual product roll-out, which will be held in Las Vegas. It is a big event that all customers are invited to. The supplier has offered to pay for all flights and accommodation, in addition to the meals that will be provided as part of the event. The supplier's contract is not currently up for renewal, and I am not the person responsible for making the decision whether to renew. Can I attend?

ANSWER: Since TransCanada has an existing business relationship with the supplier and is not currently involved in any renewal or other negotiations and since the event is a business-related event attended by many customers as well as supplier representatives, you may attend with your leader's approval. However, given the location of the event, the business benefit to TransCanada should be carefully considered and discussed with your leader. Additionally, since the value of the event is significant, the supplier's payment for flights and accommodation could create a perception of conflict and/or an obligation on the part of TransCanada. As a result, flights and accommodation should be paid for by TransCanada. You may accept the meals provided by the supplier as part of the event.

Making the Right Choices and Doing the Right Thing Requires that We Act Responsibly

In doing business, we consider the impact of our actions on TransCanada, on all of our stakeholders, on the environment and on the communities in which we operate. Acting responsibly includes protecting TransCanada's assets and those of third parties, protecting the health and safety of our workers, our neighbours and the public, protecting the environment, being a good ambassador of TransCanada, respecting human rights, being a good neighbour and member of the communities in which we live and work, and maintaining a respectful and productive workplace.

Protecting Confidential Information

We protect TransCanada's confidential information, and that of our customers, suppliers and other stakeholders, from improper disclosure and use.

We all routinely have access to confidential information. TransCanada confidential information includes all TransCanada non-public information that may be of use to competitors or harmful to TransCanada or its customers, suppliers or other stakeholders, if disclosed. It can include, but is in no way limited to, information regarding TransCanada's business, operations, finances, strategies or business plans, projects, proposed mergers, acquisitions and divestitures, engineering designs and reports, legal proceedings, contracts, environmental reports, land and lease information, technical and economic data, marketing information and field notes, sketches, photographs, electronic information assets (including emails, voicemails, SMS, and text messages), computer records or software, specifications, models, or other information which is or may be either applicable to or related in any way to the assets, business or affairs of TransCanada.

See additional information in the Protecting and Using TransCanada's Assets and the Managing and Maintaining the Security of Information sections.

Because such information is sensitive and can be used by competitors or others to TransCanada's detriment, it must be protected. You should not disclose such information to anyone who does not need to know the information (including within TransCanada). Any disclosures to external parties that are required to be made for legitimate business reasons should only be made if the recipient has signed a Confidentiality or Non-Disclosure Agreement. You should also be careful not to talk about (even with family members or friends), view or leave confidential information in a location where it could be overheard or seen by an unauthorized person (e.g. on an airplane or other public place), and you should store confidential information in a secure location, such as a locked cabinet or a password-protected or other access-restricted folder if the information is electronic. When disposing of confidential information, you should do so in a secure manner, which may include shredding of hard copies.

TransCanada's stakeholders also often provide TransCanada with their own confidential information and require, through Confidentiality or Non-Disclosure Agreements, that this information be protected from inappropriate disclosure or use. You must honour the terms of any such Confidentiality or Non-Disclosure Agreements and safeguard the information in the same way you would TransCanada's confidential information. Even if there is no Confidentiality or Non-Disclosure Agreement in place, you should always protect customer-specific information.

You must also continue to maintain the confidentiality of all confidential information obtained while at TransCanada after you leave the Company, as your obligations of confidentiality are ongoing. This means that you may not disclose any confidential information to anyone after you leave TransCanada, including your new employer.

For more information, see the Information Management Policy and Information Security Policy.

Protecting and Respecting Intellectual Property Rights

We preserve TransCanada's intellectual property rights and respect and honour those of third parties.

Intellectual property can include trade secrets, that is, any information that gives the owner an economic advantage over its competitors and that the owner takes reasonable steps to keep confidential, as well as copyrights, trademarks and patents.

TransCanada owns all inventions, discoveries and copyrighted material made or developed by TransCanada's Personnel in the course of and relating to their employment, contract or engagement with the Company, unless a written release is obtained or the issue is covered by contract.

TransCanada's intellectual property is an important Company asset. Since intellectual property rights can be lost if they are misused or not protected, you must take steps to protect these rights. This includes keeping trade secrets confidential and consistently using TransCanada's trademarks solely as authorized, including not altering fonts, formats, colours, or other details.

You must also respect and honour the intellectual property rights of third parties. This includes complying with the terms of license agreements that TransCanada has entered into with vendors. These license agreements often prohibit the sharing of user names and passwords, as well as the copying, distributing or disclosing of the licensed information to any individuals within TransCanada that are not licensed users.

Respecting and honouring third party intellectual property rights also includes complying with copyright legislation, by not copying protected material without either a license to do so, or the permission of the owner.

Finally, you must respect third party patents and trade secrets by not using improper means to obtain such information, and by not using confidential third party information for a purpose other than that for which it was provided.

Protecting and Using TransCanada's Assets

We protect TransCanada's assets and use them only for legitimate business purposes.

You have an obligation to be a good steward of the assets that TransCanada provides to help you perform your job, including equipment, facilities, furniture, computers, telephones, supplies, tools, personal protective equipment, corporate credit cards, and other resources. This means protecting these assets from loss, theft, damage, and misuse.

You must comply with all security protocols, for example, locking your laptop, and not letting strangers into Company facilities without a TransCanada escort and/or appropriate identification. For more information see the Corporate Security Policy.

Although TransCanada resources are intended to be used for business purposes, occasional limited personal use of Company resources such as telephones, photocopiers, and the Internet are permitted. Such use should not be excessive. You must never use Company resources for any illegal or inappropriate purposes, such as viewing pornography, engaging in hate-based communications or other activities, downloading pirated movies or other illegal material, or other inappropriate use. TransCanada reserves the right to monitor Company computer use, and employees should not assume any right of privacy with respect to either their use of, or data stored on, TransCanada's computer systems. TransCanada regularly monitors employee use of its equipment and systems, and anything that comes to TransCanada's attention as a result of such monitoring may be the subject of disciplinary action. For more information please see the Acceptable Use Policy.

QUESTION: I sometimes use my Company computer to access Facebook or Twitter during my lunch break and I talk about my personal life. Is that allowed?

ANSWER: Limited personal use of corporate assets to access social media on your own time is acceptable; however, you need to keep in mind that you are using a corporate computer and accessing the Internet through a TransCanada IP address. So, you must be careful to ensure that you do not post inappropriate or offensive content, nor do or say anything that could reflect poorly on TransCanada. TransCanada also has the right to monitor your personal use of its equipment and systems and you should not expect your use of TransCanada assets for these purposes to be private. TransCanada regularly monitors employee use of its equipment and systems and you may be subject to disciplinary action for any inappropriate or offensive use that comes to TransCanada's attention as a result of such monitoring.

Managing and Maintaining the Security of Information

We recognize the importance of corporate records as valuable assets of the Company and we manage, protect and preserve these assets accordingly.

Information assets can include everything from memos, emails, accounting records, invoices and contracts, to technical drawings, recordings of trade-related phone calls, records of safety or other incidents, marketing literature, and other similar types of records. They can also be in any form or on any media, including, paper, CD, DVD, voice recordings, or other electronic formats.

All of these assets are important Company records that TransCanada may be required to produce in the event of a legal or regulatory proceeding, audit or investigation. It is important that you manage and retain these assets in accordance with all legal requirements and corporate policies. In particular, you must never destroy an information asset in the event of an actual or pending legal or regulatory proceeding. Business activities should not be conducted through any medium that cannot be produced as a record (e.g. SMS, texts etc. are to be avoided).

It is also important to protect the security of TransCanada's information assets. You must comply with all internal policies and procedures concerning information security. Please refer to the End User Computing Standard, Information Management Policy, Information Security Policy, and the Password Standard for further information.

Being Socially Responsible

We respect human rights and we are committed to being a good neighbour and supporting and enhancing the communities in which we live and work.

Some of the most important communities our business impacts are the Indigenous communities. We are committed to working with these communities, to develop positive, long-term relationships based on mutual trust and respect, and recognizing their diversity and the importance they place on the land, their culture and their traditional way of life.

TransCanada partners in supporting safe, healthy and vibrant Indigenous communities by investing in various community, cultural, educational, and environmental initiatives and events. For more information, please see the Stakeholder Engagement Commitment Statement, and the Aboriginal and Native American Relations policies.

In addition to working with the Indigenous communities, we also work hard to build and maintain relationships with other landowners. We recognize the importance of farming to their communities, and actively support farming-related organizations.

We also understand the importance that community, charitable and other similar non-governmental organizations play in making the communities in which we live and work better places. TransCanada actively supports these organizations and encourages you to also become involved.

You are encouraged to volunteer and to contribute to charitable and other community-based organizations, including during work hours if approved by your leader. Charitable donations should not, however, be made to improperly influence government officials or others. Please see the section on Avoiding Bribery and Corruption and the Avoiding Bribery and Corruption Policy for more information.

Being a Good Ambassador of TransCanada

We recognize that we are ambassadors of TransCanada and conduct ourselves in a manner that is respectful and appropriate and that will not harm TransCanada's reputation.

You must keep in mind that you are a representative of TransCanada. The things you say and do should reflect the Company's core values. You should not speak publicly on behalf of TransCanada unless authorized to do so. Any posting or statement on an external website, including personal sites or in other media should be considered a public statement.

Even on your personal time, you must not participate in any illegal or inappropriate statements or activities that could be detrimental to the Company or its reputation with TransCanada's name or brand. For example, while you may indicate on your social media profile(s) that TransCanada is your employer, if you do so, you must ensure that you do not post inappropriate content that could reflect poorly on the Company.

For more information, see the Public Disclosure Policy and Communication Policy.

Protecting Individuals' Privacy

We respect and protect the privacy rights and personal information of our employees and other stakeholders.

TransCanada takes very seriously the fact that its Personnel, customers, suppliers, and other stakeholders have entrusted the Company with their personal information. The Company is committed to protecting that information in compliance with all legal requirements.

Some examples of personal information include an individual's name, home address, telephone number, identification numbers (such as an employee number or social insurance/social security number), financial information, and medical information.

You should never collect, store, access, use, or disclose personal information for an inappropriate purpose or by inappropriate or illegal means. To the extent that you have personal information of any individual as a result of your work at TransCanada, whether the individual is an employee, a landowner, a shareholder, or a party that TransCanada does business with (to name just a few examples), you may not disclose that personal information to others, either within or outside TransCanada, without the express approval of TransCanada's Privacy Officer or the individual's consent. Use of personal information must be limited to the business purposes for which the information was provided. You should also protect and safeguard personal information from inappropriate access, by keeping it in a locked cabinet, or in a password protected or otherwise restricted folder, memory stick or other similar storage device, if the information is electronic.

If the information is requested by anyone within or outside the Company, or if it needs to be disclosed for any legitimate reason, you should check with TransCanada's Privacy Officer before taking any action.

For more information, please see the Protection of Personal Information Policy.

Diversity and Employment Equity/Equal Opportunity

We respect and embrace our differences and are committed to principles of employment equity/equal opportunity, non-discrimination and accommodation.

TransCanada believes that our differences make us stronger. The Company promotes and encourages a culture of diversity, inclusion and acceptance, prohibits any form of discrimination on legally prohibited grounds, and requires reasonable accommodation of differences. We recognize that in some cases, treating people fairly requires that you treat them equally and in other cases it requires that you accommodate their differences.

TransCanada requires you to be inclusive and to demonstrate respect for and acceptance of others. While acting on behalf of TransCanada, you must never discriminate against anyone on the basis of a legally prohibited ground, including gender, race, national or ethnic origin, colour, religion, age, sexual orientation, marital status, family status, veteran status, disability, or conviction.

If you are a leader or are otherwise responsible for employment-related decisions, you must make those decisions objectively, in compliance with all legal requirements and corporate policies, on the basis of the Company's and the job's requirements, and without discrimination on the basis of a prohibited ground. You also must never discount an individual due to a difference which can reasonably be accommodated. Reasonable accommodation of differences must also be provided as and when required.

Please refer to the Reasonable Workplace Accommodation, Employment Equity and Non-Discrimination, Equal Employment Opportunity, Affirmative Action and Non-Discrimination (United States) and the Harassment-Free Workplace policies for further information.

Stan Chapman
Executive Vice-President and President, U.S. Natural Gas Pipelines

> *For a company that operates in three countries across multiple provinces and states, diversity is all in a day's work. We have a wide variety of backgrounds, perspectives and skills in our workforce. When we respect and value those differences, we drive innovation, growth and competitiveness.*

Maintaining a Harassment, Violence and Weapons-Free Workplace

We treat one another with dignity and respect and are committed to maintaining a work environment that is free of harassment, violence and weapons.

Everyone deserves the opportunity to do their job in safe environment, without fear of harassment or violence (including the use of weapons).

You must always be respectful to your co-workers, and be sensitive to the way in which others may react to your behaviours and comments. Always try to resolve differences in a calm and respectful manner, without resorting to insults, threats or violence.

TransCanada prohibits any behaviour that is intimidating, hostile, offensive, threatening, violent, demeaning, or humiliating, or of a sexual nature, that either interferes with an individual's work performance or creates an inappropriate work environment. In particular, you should never take actions or make unwanted comments or gestures that relate to gender, race, national or ethnic origin, disability, religion, age, sexual orientation, marital status, family status, veteran status, National Guard or reserve unit obligations, a conviction, or any other legally protected status.

The Company prohibits the possession, use, carrying, and transportation of any Dangerous or Potentially Dangerous Weapon(s) when conducting Company business as defined by TransCanada's Weapons in the Workplace Policy. This prohibition applies on or off all Company owned or controlled premises, in all Company vehicles, and to all personal vehicles being used in the course of Company business.

Personnel licensed to carry firearms (openly or in a concealed manner) or weapons are not exempt from the Policy.

For Personnel in jurisdictions that permit firearms to be kept in personal vehicles, the vehicle must be locked, the firearms must be hidden from plain view, and be kept within a locked case or container within the vehicle.

For more information, please see the Harassment-Free Workplace and the Weapons in the Workplace policies.

You are encouraged to suggest or develop new procedures and methods of working that will help ensure TransCanada's compliance with legal and ethical requirements. Even if you don't have a solution, you should speak up if you see something that needs to be improved. Any of the people listed below may be contacted or alternatively, you can contact the Ethics Help Line.

- Your leader
- Your Human Resources Consultant
- Your Compliance Coordinator
- Corporate Compliance Department
- Internal Audit
- Law Department

If you are aware of someone who has improved TransCanada's compliance or ethics related processes or activities, or who has pointed out a flaw in the way we currently do things that will allow for improvement, contact the Corporate Compliance Department as we want to know about it.

For more specific policy information on any of the topics referred to in COBE please refer to the Corporate Policies page on Infocus, contact any of the people listed above or the Ethics Help Line.

GLOSSARY

Confidential Information means all TransCanada non-public information that may be of use to competitors or harmful to TransCanada or its customers, suppliers, or other stakeholders, if disclosed. It can include, but is in no way limited to, information regarding TransCanada's business, operations, finances, strategies or business plans, projects, proposed mergers, acquisitions and divestitures, engineering designs and reports, legal proceedings, contracts, environmental reports, land, and lease information, technical and economic data, marketing information and field notes, sketches, photographs, electronic information assets (including emails, voicemails, SMS, and text messages), computer records or software, specifications, models, or other information which is or may be either applicable to or related in any way to the assets, business or affairs of TransCanada.

Contingent Workforce Contractor (CWC) means individuals, either Independent Consultants or contract workers employed by a third party Contingent Workforce Supplier, to work at or on behalf of TransCanada using TransCanada infrastructure (e.g. workstation, email, phone), and compensated on an hourly rate basis, performing work under the direction of a TransCanada leader.

Direct Reporting means a reporting relationship in which Personnel report to a Family member or person with whom they have a Significant Personal Relationship where that leader is responsible for hiring, delegating work, performance assessment and management, and/or making decisions related to terms of employment, including but not limited to compensation decisions.

Employee means full-time and part-time employees of TransCanada including student employees.

Family or Other Significant Personal Relationship means, but is not limited to, a spouse (including common-law and same gender spouses), parent, grandparent, child, grandchild, sibling, aunt or uncle, niece or nephew, cousin, or an individual who has acquired such a relationship through marriage/common-law, or any "step", "common-law" or "in-law" variations of these relationships.

Good Faith Reporting means an open, honest, fair and reasonable reporting without malice or ulterior motive.

Independent Consultant means individuals acting in their own right and often providing services in a professional capacity and submitting invoices for services rendered directly to TransCanada. Independent Consultants are considered a type of Non-Preferred Supplier.

Indirect Reporting means a reporting relationship where the applicable Personnel's Family or other Significant Personal Relationship resides anywhere in their reporting structure.

Personnel means full-time, temporary and part-time employees, Contingent Workforce Contractors (CWC), and Independent Consultants.

Records means information created, received and maintained as evidence by an organization or person, pursuant to legal obligations or in the transaction of business. Records include, but are not limited to, electronic and physical formats. They provide proof of what happened, when

it happened, and who made decisions. Whether information is identified as a Record depends on the information it contains and the context.

TransCanada or the Company means TransCanada Corporation and its wholly-owned subsidiaries and/or operated entities.