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.

KPMG LLP

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 approximately 53.8 million Columbia Pipeline Partners LP (CPPL) common units outstanding to the public as of June 30, 2016, and valued at the June 30, 2016 closing price of US$15.00 per common unit. On February 17, 2017, TransCanada acquired all outstanding publicly held common units of CPPL. Refer to Note 19, Non-controlling interests, for further information.

In 2016, acquisition expenses of approximately $36 million were included in Plant operating costs and other in the Consolidated statement of income.

Upon completion of the acquisition, the Company began consolidating Columbia. Columbia's significant accounting policies were consistent with TransCanada's and continued to be applied. Columbia contributed $929 million to the Company's Revenues and $132 million to the Company's net income from July 1, 2016 to December 31, 2016.

The following supplemental pro forma consolidated financial information of the Company for the years ended December 31, 2016 and 2015 includes the results of operations for Columbia as if the acquisition had been completed on January 1, 2015.

year ended December 31 (millions of Canadian $)	**2016**	**2015**
Revenues	**13,404**	13,007
Net Income/(Loss)	**627**	(820)
Net Income/(Loss) Attributable to Common Shares	**234**	(971)

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			Equity Investments at December 31	
		2017	2016	2015	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 than 10 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 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, 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) Borrower	Description	Matures	2017 Total Facilities	2017 Unused Capacity	2016 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:

year ended December 31	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
	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 Pension Benefits	2017 Other Post-Retirement Benefits	2016 Pension Benefits	2016 Other Post-Retirement Benefits	2015 Pension Benefits	2015 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 Pension Benefits	2017 Other Post-Retirement Benefits	2016 Pension Benefits	2016 Other Post-Retirement Benefits	2015 Pension Benefits	2015 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 and no 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 at December 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 at December 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. As at 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:

		2017		2016	
year ended December 31 (millions of Canadian $)	**Term**	**Potential Exposure**[1]	**Carrying Value**	**Potential Exposure**[1]	**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 $86 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 a 100 per cent voting interest, the VIE meets the definition of a business and the VIE's assets can be used for general corporate purposes. The Consolidated VIEs whose assets cannot be used for purposes other than for the settlement of the VIE's obligations 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