Management's Report on Internal Control over Financial Reporting

The consolidated financial statements and Management's Discussion and Analysis (MD&A) included in this Annual Report are the responsibility of the management of TC Energy Corporation (TC Energy or the Company) and have been approved by the Board of Directors of the Company. The consolidated financial statements have been prepared by management in accordance with United States generally accepted accounting principles (GAAP) and include amounts that are based on estimates and judgments. The MD&A is based on the Company's financial results. It compares the Company's financial and operating performance in 2019 to that in 2018, and highlights significant changes between 2018 and 2017. The MD&A should be read in conjunction with the consolidated financial statements and accompanying notes. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Management has designed and maintains a system of internal control over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. The internal control over financial reporting includes management's communication to employees of policies that govern ethical business conduct.

Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management concluded, based on its evaluation, that internal control over financial reporting was effective as of December 31, 2019, 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, Strategy & Corporate Development and
Chief Financial Officer

February 12, 2020

Report of Independent Registered Public Accounting Firm

To the Shareholders of TC Energy Corporation

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of TC Energy Corporation (the Company) as of December 31, 2019, and 2018, 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, 2019, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019, and 2018, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 12, 2020 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective or complex judgment. The communication of a critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Evaluation of qualitative goodwill impairment indicators

As discussed in Note 12 to the consolidated financial statements, the goodwill balance as of December 31, 2019 was $12,887 million. The Company assesses goodwill for impairment testing on an annual basis, or more frequently if events or changes in circumstances indicate that the carrying value of a reporting unit, including goodwill, might be impaired. In the current year, the Company only performed qualitative assessments of relevant events and changes in circumstances to determine whether there was more than a 50 per cent likelihood that the fair value of each reporting unit was less than its carrying value. These qualitative assessments were performed as of December 31, 2019, as well as at June 30, 2019 when certain Columbia midstream assets related to the Columbia Pipeline Group reporting unit were classified as held for sale.

We identified the evaluation of qualitative goodwill impairment indicators, or qualitative factors, as a critical audit matter. Relevant events or changes in circumstances could indicate possible impairment of goodwill, which required the application of complex auditor judgment. Potential qualitative factors included the disposal of certain Columbia midstream assets, macroeconomic conditions, industry and market considerations, cost factors, historical and forecasted financial results, and events specific to the entity and reporting units, which required a higher degree of auditor judgment to evaluate. These potential qualitative factors could have a significant effect on the Company's assessment and the need to perform a quantitative goodwill impairment test.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's goodwill impairment assessment process, including controls related to the assessment of potential qualitative factors. We evaluated the Company's assessment for its reporting units by considering any event specific changes to the entity and reporting units identified by the Company against other evidence obtained through other procedures. We evaluated information from analyst reports in the energy and utility industries, which were compared to geopolitical and market considerations used by the Company, including an assessment of pipeline system capacity on existing pipeline networks, the volumetric reserves of the basins supplying the respective reporting units to support forecasted revenue growth, and global energy consumption forecasts. We analyzed cost factors, financial performance of the reporting units, and other entity and reporting-unit specific events, including the impact of newly approved growth pipeline projects and the ability of existing customers to fulfill current contract terms. In addition, we involved a valuation professional with specialized skills and knowledge, who assisted in analyzing the changes in the qualitative growth potential and risk profile of the reporting units compared to assumptions used in quantitative goodwill impairment tests performed in previous periods.

KPMG LLP

Chartered Professional Accountants

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

Calgary, Canada
February 12, 2020

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of TC Energy Corporation

Opinion on Internal Control Over Financial Reporting

We have audited TC Energy Corporation's (the Company) internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2019 and 2018, 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, 2019, and the related notes (collectively, the consolidated financial statements), and our report dated February 12, 2020 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

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

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 12, 2020

Consolidated statement of income

year ended December 31 (millions of Canadian $, except per share amounts)	2019	2018	2017
Revenues (Note 5)			
Canadian Natural Gas Pipelines	**4,010**	4,038	3,693
U.S. Natural Gas Pipelines	**4,978**	4,314	3,584
Mexico Natural Gas Pipelines	**603**	619	570
Liquids Pipelines	**2,879**	2,584	2,009
Power and Storage	**785**	2,124	3,593
	13,255	13,679	13,449
Income from Equity Investments (Note 10)	**920**	714	773
Operating and Other Expenses			
Plant operating costs and other	**3,909**	3,591	3,906
Commodity purchases resold	**369**	1,488	2,382
Property taxes	**727**	569	569
Depreciation and amortization	**2,464**	2,350	2,055
Goodwill and other asset impairment charges (Notes 8, 12 and 13)	**—**	801	1,257
	7,469	8,799	10,169
(Loss)/Gain on Assets Held for Sale/Sold (Notes 6 and 27)	**(121)**	170	631
Financial Charges			
Interest expense (Note 18)	**2,333**	2,265	2,069
Allowance for funds used during construction	**(475)**	(526)	(507)
Interest income and other	**(460)**	76	(184)
	1,398	1,815	1,378
Income before Income Taxes	**5,187**	3,949	3,306
Income Tax Expense/(Recovery) (Note 17)			
Current	**699**	315	149
Deferred	**55**	284	566
Deferred – U.S. Tax Reform and 2018 FERC Actions	**—**	(167)	(804)
	754	432	(89)
Net Income	**4,433**	3,517	3,395
Net income/(loss) attributable to non-controlling interests (Note 20)	**293**	(185)	238
Net Income Attributable to Controlling Interests	**4,140**	3,702	3,157
Preferred share dividends	**164**	163	160
Net Income Attributable to Common Shares	**3,976**	3,539	2,997
Net Income per Common Share (Note 21)			
Basic	**$4.28**	$3.92	$3.44
Diluted	**$4.27**	$3.92	$3.43
Dividends Declared per Common Share	**$3.00**	$2.76	$2.50
Weighted Average Number of Common Shares (millions) (Note 21)			
Basic	**929**	902	872
Diluted	**931**	903	874

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 $)	2019	2018	2017
Net Income	**4,433**	3,517	3,395
Other Comprehensive (Loss)/Income, Net of Income Taxes			
Foreign currency translation losses and gains on net investment in foreign operations	**(944)**	1,358	(749)
Reclassification of foreign currency translation gains on disposal of foreign operations	**(13)**	—	(77)
Change in fair value of net investment hedges	**35**	(42)	—
Change in fair value of cash flow hedges	**(62)**	(10)	3
Reclassification to net income of gains and losses on cash flow hedges	**14**	21	(2)
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**(10)**	(114)	(11)
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**10**	15	16
Other comprehensive (loss)/income on equity investments	**(82)**	86	(106)
Other comprehensive (loss)/income (Note 23)	**(1,052)**	1,314	(926)
Comprehensive Income	**3,381**	4,831	2,469
Comprehensive income/(loss) attributable to non-controlling interests	**194**	(13)	83
Comprehensive Income Attributable to Controlling Interests	**3,187**	4,844	2,386
Preferred share dividends	**164**	163	160
Comprehensive Income Attributable to Common Shares	**3,023**	4,681	2,226

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 $)	2019	2018	2017
Cash Generated from Operations			
Net income	**4,433**	3,517	3,395
Depreciation and amortization	**2,464**	2,350	2,055
Goodwill and other asset impairment charges (Notes 8, 12 and 13)	**—**	801	1,257
Deferred income taxes (Note 17)	**55**	284	566
Deferred income taxes – U.S. Tax Reform and 2018 FERC Actions (Note 17)	**—**	(167)	(804)
Income from equity investments (Note 10)	**(920)**	(714)	(773)
Distributions received from operating activities of equity investments (Note 10)	**1,213**	985	970
Employee post-retirement benefits funding, net of expense (Note 24)	**(45)**	(35)	(64)
Loss/(gain) on assets held for sale/sold (Notes 6 and 27)	**121**	(170)	(631)
Equity allowance for funds used during construction	**(299)**	(374)	(362)
Unrealized (gains)/losses on financial instruments	**(134)**	220	(149)
Foreign exchange (gains)/losses on Loan receivable from affiliate (Note 10)	**(53)**	5	63
Other	**(46)**	(45)	(20)
Decrease/(increase) in operating working capital (Note 26)	**293**	(102)	(273)
Net cash provided by operations	**7,082**	6,555	5,230
Investing Activities			
Capital expenditures (Note 4)	**(7,475)**	(9,418)	(7,383)
Capital projects in development (Note 4)	**(707)**	(496)	(146)
Contributions to equity investments (Notes 4 and 10)	**(602)**	(1,015)	(1,681)
Proceeds from sales of assets, net of transaction costs	**2,398**	614	4,683
Reimbursement of costs related to capital projects in development (Note 13)	**—**	470	634
Other distributions from equity investments (Note 10)	**186**	121	362
Payment for unredeemed shares of Columbia Pipeline Group, Inc. (Note 15)	**(373)**	—	—
Deferred amounts and other	**(299)**	(295)	(168)
Net cash used in investing activities	**(6,872)**	(10,019)	(3,699)
Financing Activities			
Notes payable issued, net	**1,656**	817	1,038
Long-term debt issued, net of issue costs	**3,024**	6,238	3,643
Long-term debt repaid	**(3,502)**	(3,550)	(7,085)
Junior subordinated notes issued, net of issue costs	**1,436**	—	3,468
Dividends on common shares	**(1,798)**	(1,571)	(1,339)
Dividends on preferred shares	**(160)**	(158)	(155)
Distributions to non-controlling interests	**(216)**	(225)	(283)
Common shares issued, net of issue costs	**253**	1,148	274
Partnership units of TC PipeLines, LP issued, net of issue costs	**—**	49	225
Common units of Columbia Pipeline Partners LP acquired	**—**	—	(1,205)
Net cash provided by/(used in) financing activities	**693**	2,748	(1,419)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(6)**	73	(39)
Increase/(Decrease) in Cash and Cash Equivalents	**897**	(643)	73
Cash and Cash Equivalents			
Beginning of year	**446**	1,089	1,016
Cash and Cash Equivalents			
End of year	**1,343**	446	1,089

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

Consolidated balance sheet

at December 31 (millions of Canadian $)		2019	2018
ASSETS			
Current Assets			
Cash and cash equivalents		**1,343**	446
Accounts receivable		**2,422**	2,535
Inventories		**452**	431
Assets held for sale (Note 6)		**2,807**	543
Other (Note 7)		**627**	1,180
		7,651	5,135
Plant, Property and Equipment (Note 8)		**65,489**	66,503
Loan Receivable from Affiliate (Note 10)		**1,434**	1,315
Equity Investments (Note 10)		**6,506**	7,113
Restricted Investments		**1,557**	1,207
Regulatory Assets (Note 11)		**1,587**	1,548
Goodwill (Note 12)		**12,887**	14,178
Intangible and Other Assets (Note 13)		**2,168**	1,921
		99,279	98,920
LIABILITIES			
Current Liabilities			
Notes payable (Note 14)		**4,300**	2,762
Accounts payable and other (Note 15)		**4,544**	5,408
Dividends payable		**737**	668
Accrued interest		**613**	646
Current portion of long-term debt (Note 18)		**2,705**	3,462
		12,899	12,946
Regulatory Liabilities (Note 11)		**3,772**	3,930
Other Long-Term Liabilities (Note 16)		**1,614**	1,008
Deferred Income Tax Liabilities (Note 17)		**5,703**	6,026
Long-Term Debt (Note 18)		**34,280**	36,509
Junior Subordinated Notes (Note 19)		**8,614**	7,508
		66,882	67,927
EQUITY			
Common shares, no par value (Note 21)		**24,387**	23,174
Issued and outstanding:	December 31, 2019 – 938 million shares		
	December 31, 2018 – 918 million shares		
Preferred shares (Note 22)		**3,980**	3,980
Additional paid-in capital		**—**	17
Retained earnings		**3,955**	2,773
Accumulated other comprehensive loss (Note 23)		**(1,559)**	(606)
Controlling Interests		**30,763**	29,338
Non-controlling interests (Note 20)		**1,634**	1,655
		32,397	30,993
		99,279	98,920

Commitments, Contingencies and Guarantees (Note 28)
Corporate Restructuring Costs (Note 29)
Variable Interest Entities (Note 30)

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

On behalf of the Board:

Russell K. Girling, Director

John E. Lowe, Director

Consolidated statement of equity

year ended December 31 (millions of Canadian $)	2019	2018	2017
Common Shares (Note 21)			
Balance at beginning of year	**23,174**	21,167	20,099
Shares issued:			
Under dividend reinvestment and share purchase plan	**931**	855	790
On exercise of stock options	**282**	34	62
Under at-the-market equity issuance program, net of issue costs	**—**	1,118	216
Balance at end of year	**24,387**	23,174	21,167
Preferred Shares			
Balance at beginning and end of year	**3,980**	3,980	3,980
Additional Paid-In Capital			
Balance at beginning of year	**17**	—	—
Issuance of stock options, net of exercises	**(17)**	10	6
Dilution from TC PipeLines, LP units issued	**—**	7	26
Asset drop-downs to TC PipeLines, LP	**—**	—	(202)
Columbia Pipeline Partners LP acquisition	**—**	—	(171)
Reclassification of additional paid-in capital deficit to retained earnings	**—**	—	341
Balance at end of year	**—**	17	—
Retained Earnings			
Balance at beginning of year	**2,773**	1,623	1,138
Net income attributable to controlling interests	**4,140**	3,702	3,157
Common share dividends	**(2,794)**	(2,501)	(2,184)
Preferred share dividends	**(164)**	(163)	(159)
Adjustment related to income tax effects of asset drop-downs to TC PipeLines, LP	**—**	95	—
Reclassification of AOCI to retained earnings resulting from U.S. Tax Reform	**—**	17	—
Adjustment related to employee share-based payments	**—**	—	12
Reclassification of additional paid-in capital deficit to retained earnings	**—**	—	(341)
Balance at end of year	**3,955**	2,773	1,623
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(606)**	(1,731)	(960)
Other comprehensive (loss)/income attributable to controlling interests (Note 23)	**(953)**	1,142	(771)
Reclassification of AOCI to retained earnings resulting from U.S. Tax Reform	**—**	(17)	—
Balance at end of year	**(1,559)**	(606)	(1,731)
Equity Attributable to Controlling Interests	**30,763**	29,338	25,039
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,655**	1,852	1,726
Net income/(loss) attributable to non-controlling interests	**293**	(185)	238
Other comprehensive (loss)/income attributable to non-controlling interests	**(99)**	172	(155)
Distributions declared to non-controlling interests	**(215)**	(224)	(280)
Issuance of TC PipeLines, LP units			
Proceeds, net of issue costs	**—**	49	225
Decrease in TC Energy's ownership of TC PipeLines, LP	**—**	(9)	(41)
Reclassification from common units subject to rescission (Note 20)	**—**	—	106
Impact of Columbia Pipeline Partners LP acquisition	**—**	—	33
Balance at end of year	**1,634**	1,655	1,852
Total Equity	**32,397**	30,993	26,891

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

Notes to consolidated financial statements

1. DESCRIPTION OF TC ENERGY'S BUSINESS

On May 3, 2019, TransCanada Corporation changed its name to TC Energy Corporation (TC Energy or the Company) to better reflect the scope of its operations as a leading North American energy infrastructure company. In addition, the previously disclosed Energy segment has been renamed the Power and Storage segment.

TC Energy is a leading North American energy infrastructure company which operates in five business segments, Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines and Power and Storage, each of which offers different products and services. The Company also has a Corporate segment, consisting of corporate and administrative functions that provide governance, financing and other support to the Company's business segments.

Canadian Natural Gas Pipelines

The Canadian Natural Gas Pipelines segment consists of the Company's investments in 40,658 km (25,264 miles) of natural gas pipelines primarily regulated by the Canadian Energy Regulator (CER). The Company also has an investment in the Coastal GasLink pipeline under development which is regulated by the B.C. Oil and Gas Commission (OGC).

U.S. Natural Gas Pipelines

The U.S. Natural Gas Pipelines segment consists of the Company's investments in 50,089 km (31,124 miles) of regulated natural gas pipelines, 535 Bcf of regulated natural gas storage facilities and other assets, owned directly and through the Company's investment in TC PipeLines, LP.

Mexico Natural Gas Pipelines

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

Liquids Pipelines

The Liquids Pipelines segment consists of the Company's investments in 4,946 km (3,075 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 as well as a liquids marketing business.

Power and Storage

The Power and Storage segment primarily consists of the Company's investments in 10 power generation facilities and 118 Bcf of non-regulated natural gas storage facilities. These assets are located in Alberta, Ontario, Québec and New Brunswick and include the investment in Portlands Energy Centre as well as the Halton Hills and Napanee natural gas-fired power plants which were classified as Assets held for sale at December 31, 2019. Refer to Note 6, Assets held for sale, for additional information.

2. ACCOUNTING POLICIES

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

Basis of Presentation

These consolidated financial statements include the accounts of TC Energy and its subsidiaries. The Company consolidates variable interest entities (VIEs) for which it is considered to be the primary beneficiary as well as voting interest entities in which it has a controlling financial interest. To the extent there are interests owned by other parties, these interests are included in non-controlling interests. TC Energy uses the equity method of accounting for joint ventures in which the Company is able to exercise joint control and for investments in which the Company is able to exercise significant influence. TC Energy 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, TC Energy is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgment in making these estimates and assumptions.

Certain estimates and judgments have a material impact where the assumptions underlying these accounting estimates relate to matters that are highly uncertain at the time the estimate or judgment is made or are subjective. These estimates and judgments include, but are not limited to:

- fair value of equity investments (Note 10) and the recoverability of plant, property and equipment (Note 8)
- fair value of reporting units that contain goodwill (Notes 12 and 27)
- recoverability of capitalized project costs (Note 13) and
- fair value of assets and liabilities acquired in a business combination.

Some of the estimates and judgments the Company has to make have a material impact on the consolidated financial statements, but they do not involve significant subjectivity or uncertainty. These estimates and judgments include, but are not limited to:

- depreciation rates of plant, property and equipment (Note 8)
- carrying value of regulatory assets and liabilities (Note 11)
- carrying value of asset retirement obligations (Note 16)
- provisions for income taxes, including U.S. Tax Reform (Note 17)
- assumptions used to measure retirement and other post-retirement obligations (Note 24)
- fair value of financial instruments (Note 25) and
- provisions for commitments, contingencies, guarantees (Note 28) and restructuring costs (Note 29).

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 CER, formerly the National Energy Board (NEB), the Alberta Energy Regulator (AER) or the OGC. In the U.S., regulated natural gas pipelines, liquids pipelines and regulated natural gas storage assets are subject to the authority of the Federal Energy Regulatory Commission (FERC). In Mexico, regulated natural gas pipelines are subject to the authority of the Energy Regulatory Commission (CRE). Rate-regulated accounting (RRA) standards may impact the timing of the recognition of certain revenues and expenses in TC Energy's rate-regulated businesses which may differ from that otherwise recognized in non-rate-regulated businesses to appropriately reflect the economic impact of the regulators' decisions regarding revenues and tolls. Regulatory assets represent costs that are expected to be recovered in customer rates in future periods and regulatory liabilities represent amounts that are expected to be returned to customers through future rate-setting processes. An asset qualifies for the use of RRA when it meets three criteria:

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

TC Energy's businesses that apply RRA currently include Canadian, U.S. and Mexico natural gas pipelines, and regulated U.S. natural gas storage. RRA is not applicable to the Company's liquids pipelines as the regulators' decisions regarding operations and tolls on those systems generally do not have an impact on timing of recognition of revenues and expenses. Once in operation, the Coastal GasLink pipeline is not expected to apply RRA.

Revenue Recognition

The total consideration for services and products to which the Company expects to be entitled can include fixed and variable amounts. The Company has variable revenue that is subject to factors outside the Company's influence, such as market prices, actions of third parties and weather conditions. The Company considers this variable revenue to be "constrained" as it cannot be reliably estimated and, therefore, recognizes variable revenue when the service is provided.

Canadian Natural Gas Pipelines

Capacity Arrangements and Transportation

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

Revenues from the Company's Canadian natural gas pipelines under federal jurisdiction are subject to regulatory decisions by the CER. The tolls charged on these pipelines are based on revenue requirements designed to recover the costs of providing natural gas capacity for transportation services, which includes a return of and on capital, as approved by the CER. The Company's Canadian natural gas pipelines are generally not subject to risks related to variances in revenues and most costs. These variances are generally subject to deferral treatment and are recovered or refunded in future tolls. Revenues recognized prior to a CER decision on rates for that period reflect the CER's last approved return on equity (ROE) assumptions. Adjustments to revenues are recorded when the CER decision is received. Canadian natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

U.S. Natural Gas Pipelines

Capacity Arrangements and Transportation

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

The Company's U.S. natural gas pipelines are subject to FERC regulations and, as a result, a portion of revenues collected may be subject to refund if invoiced during an interim period when a rate proceeding is ongoing. Allowances for these potential refunds are recognized using management's best estimate based on the facts and circumstances of the proceeding. Any allowances that are recognized during the proceeding process are refunded or retained at the time a regulatory decision becomes final. U.S. natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Natural Gas Storage and Other

Revenues from the Company's regulated U.S. natural gas storage services are generated mainly from firm committed capacity storage contracts. The performance obligation in these contracts is the reservation of a specified amount of capacity for storage including specifications with regards to the amount of natural gas that can be injected or withdrawn on a daily basis. Revenues are recognized ratably over the contract period for firm committed capacity regardless of the amount of natural gas that is stored, and when gas is injected or withdrawn for interruptible or volumetric-based services. Natural gas storage services revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it stores for customers.

The Company owns mineral rights associated with certain natural gas storage facilities. These mineral rights can be leased or contributed to producers of natural gas in return for a royalty interest which is recognized when natural gas and associated liquids are produced.

During 2019, TC Energy sold certain Columbia midstream assets. Prior to the sale, revenues from the Company's midstream natural gas services, including gathering, treating, conditioning, processing, compression and liquids handling services, were generated from contractual arrangements and were recognized ratably over the term of the contract. Midstream natural gas service revenues were invoiced and received on a monthly basis. The Company did not take ownership of the natural gas for which it provided midstream services. Refer to Note 27, Acquisitions and dispositions, for additional information regarding the sale of the midstream assets.

Mexico Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's Mexico natural gas pipelines are primarily collected based on CRE-approved negotiated firm capacity contracts and are generally recognized ratably over the term of the contract. Transportation revenues related to interruptible or volumetric-based services are recognized when the service is performed. Mexico natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Liquids Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's liquids pipelines are generated mainly from providing customers with firm capacity arrangements to transport crude oil. The performance obligation in these contracts is the reservation of a specified amount of capacity together with the transportation of crude oil on a monthly basis. Revenues earned from these arrangements are recognized ratably over the term of the contract regardless of the amount of crude oil that is transported. Revenues for interruptible or volumetric-based services are recognized when the service is performed. Liquids pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the crude oil that it transports for customers.

Other

Net revenues earned from the sale of proprietary crude oil are recognized in the month of delivery.

Power and Storage

Power Generation

Revenues from the Company's Power and Storage business are primarily derived from long-term contractual commitments to provide power capacity to meet the demands of the market, and from the sale of electricity to both centralized markets and to customers. Power generation revenues also include revenues from the sale of steam to customers. Revenues and capacity payments are recognized as the services are provided and as electricity and steam is delivered. Power generation revenues are invoiced and received on a monthly basis.

Natural Gas Storage and Other

Non-regulated natural gas storage contracts include park, loan and term storage arrangements. Revenues are recognized as the services are provided. Term storage revenues are invoiced and received on a monthly basis. Revenues earned from the sale of proprietary natural gas are recognized in the month of delivery. Revenues from ancillary services are recognized as the service is provided. The Company does not take ownership of the natural gas that it stores for customers.

Cash and Cash Equivalents

The Company's Cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

Inventories

Inventories primarily consist of materials and supplies including spare parts and fuel, crude oil in transit and natural gas inventory in storage. Inventories are carried at the lower of cost and net realizable value.

Assets Held for Sale

The Company classifies assets as held for sale when management approves and commits to a formal plan to actively market a disposal group and expects the sale to close within the next 12 months. Upon classifying an asset as held for sale, the asset is recorded at the lower of its carrying amount or its estimated fair value, net of selling costs, and any losses are recognized in net income. Gains related to the expected sale of these assets are not recognized until the transaction closes. Once an asset is classified as held for sale, depreciation expense is no longer recorded.

Plant, Property and Equipment

Natural Gas Pipelines

Plant, property and equipment for natural gas pipelines is carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and compression equipment are depreciated at annual rates ranging from one per cent to seven per cent, and metering and other plant equipment are depreciated at various rates reflecting their estimated useful lives. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. The cost of regulated natural gas pipelines includes an allowance for funds used during construction (AFUDC) consisting of a debt component and an equity component based on the rate of return on rate base approved by regulators. AFUDC is reflected as an increase in the cost of the assets in Plant, property and equipment with a corresponding credit recognized in Allowance for funds used during construction in the Consolidated statement of income. The equity component of AFUDC is a non-cash expenditure. Interest is capitalized during construction of non-regulated natural gas pipelines.

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

When regulated natural gas pipelines retire plant, property and equipment from service, the original book cost is removed from the gross plant amount and recorded as a reduction to accumulated depreciation. Costs incurred to remove plant, property and equipment from service, net of any salvage proceeds, are also recorded in accumulated depreciation.

Midstream and Other

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

Prior to their sale in 2019, plant, property and equipment for midstream assets was carried at cost. Depreciation was calculated on a straight-line basis once the assets were ready for their intended use. Gathering and processing facilities were depreciated at annual rates ranging from 1.7 per cent to 2.5 per cent, and other plant and equipment were depreciated at various rates. When these assets were retired from plant, property and equipment, the original book cost and related accumulated depreciation were derecognized and any gain or loss was recorded in net income. Refer to Note 27, Acquisitions and dispositions, for additional information.

Liquids Pipelines

Plant, property and equipment for liquids pipelines is carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and pumping equipment are depreciated at annual rates ranging from two per cent to 2.5 per cent , and other plant and equipment are depreciated at various rates. The cost of these assets includes interest capitalized during construction. When liquids pipelines retire plant, property and equipment from service, the original book cost and related accumulated depreciation are derecognized and any gain or loss is recorded in net income.

Power and Storage

Plant, property and equipment for Power and Storage assets are recorded at cost and, once the assets are ready for their intended use, depreciated by major component on a straight-line basis over their estimated service lives at average annual rates ranging from two per cent to 20 per cent. Other equipment is depreciated at various rates. 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 four per cent to 20 per cent.

Capitalized Project Costs

The Company capitalizes project costs once advancement of the project to a construction stage is probable or costs are otherwise likely to be recoverable. The Company also capitalizes interest costs for non-regulated projects in development and AFUDC for regulated projects in development. Capital projects in development are included in Intangible and other assets on the Consolidated balance sheet. These represent larger projects that generally require regulatory or other approvals before physical construction can begin. Once approvals are received, projects are moved to plant, property and equipment under construction.

Impairment of Long-Lived Assets

The Company reviews long-lived assets such as plant, property and equipment, equity investments and capital projects in development for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows for an asset within plant, property and equipment, or the estimated selling price of any long-lived asset is less than the carrying value of an asset, an impairment loss is recognized for the excess of the carrying value over the estimated fair value of the asset.

Acquisitions and Goodwill

The Company accounts for business combinations using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair values at the date of acquisition. The excess of the fair value of the consideration transferred over the estimated fair value of the net assets acquired is classified as goodwill. Goodwill is not amortized and is tested for impairment on an annual basis or more frequently if events or changes in circumstances indicate that it might be impaired.

The annual review for goodwill impairment is performed at the reporting unit level which is one level below the Company's operating segments. The Company can initially assess qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired. The factors the Company considers include, but are not limited to, macroeconomic conditions, industry and market considerations, cost factors, historical and forecasted financial results, and events specific to that reporting unit. If the Company concludes that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, the Company will then perform a quantitative goodwill impairment test. The Company can elect to proceed directly to the quantitative goodwill impairment test for any of its reporting units. If the quantitative goodwill impairment test is performed, the Company compares the fair value of the reporting unit to its carrying value, including its goodwill. If the carrying value of a reporting unit exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. When a portion of a reporting unit that constitutes a business is disposed, goodwill associated with that business is included in the carrying amount of the business in determining the gain or loss on disposal. The amount of goodwill disposed is determined based on the relative fair values of the business to be disposed and the portion of the reporting unit that will be retained. A goodwill impairment test will be completed for both the goodwill disposed and the portion of the goodwill for the reporting unit that will be retained.

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. TC Energy has PPAs for the sale of power that are accounted for as operating leases where TC Energy is the lessor.

Restricted Investments

The Company has certain investments that are restricted as to their withdrawal and use. These restricted investments are classified as available for sale and are recorded at fair value on the Consolidated balance sheet.

As a result of the CER's Land Matters Consultation Initiative (LMCI), TC Energy is required to collect funds to cover estimated future pipeline abandonment costs for all CER regulated Canadian pipelines. Funds collected are placed in trusts that hold and invest the funds and are accounted for as restricted investments. LMCI restricted investments may only be used to fund the abandonment of the CER regulated pipeline facilities, therefore, a corresponding regulatory liability is recorded on the Consolidated balance sheet. The Company also has other restricted investments that have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes. This method requires the recognition of deferred income tax assets and liabilities for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be reversed or settled. Changes to these balances are recognized in net income in the period in which they occur, except for changes in balances related to regulated natural gas pipelines which are deferred until they are refunded or recovered in tolls, as permitted by the regulator. Deferred income tax assets and liabilities are classified as non-current on the Consolidated balance sheet.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for asset retirement obligations (ARO) in the period in which it is incurred, when a legal obligation exists and a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted through charges to Operating and other expenses.

For those AROs that the Company records, the following assumptions are used:
- when the asset is expected to be retired
- the scope and cost of abandonment and reclamation activities that are required, and
- appropriate inflation and discount rates.

The Company has recorded AROs related to its non-regulated natural gas storage operations, mineral rights and power generation facilities. The scope and timing of asset retirements related to most of the Company's natural gas pipelines and liquids pipelines is indeterminable because the Company intends to operate them as long as there is supply and demand. As a result, the Company has not recorded an amount for ARO related to these assets, with the exception of certain abandoned facilities and certain other facilities on its Columbia Gas pipeline.

Environmental Liabilities

The Company records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. These estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations, and are subject to revision in future periods based on actual costs incurred or new circumstances. Amounts expected to be recovered from other parties, including insurers, are recorded as an asset separate from the associated liability.

Emission allowances or credits purchased for compliance are recorded on the Consolidated balance sheet at historical cost and expensed when they are utilized or cancelled/retired by government agencies. Compliance costs are expensed when incurred. Allowances granted to or internally generated by TC Energy are not attributed a value for accounting purposes. When required, TC Energy 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

TC Energy's Stock Option Plan permits options for the purchase of common shares to be awarded to certain employees, including officers. Stock options granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated using a binomial model and is recognized on a straight-line basis over the vesting period with an offset to Additional paid-in capital. Forfeitures are accounted for when they occur. Upon exercise of stock options, amounts originally recorded against Additional paid-in capital are reclassified to Common shares on the Consolidated balance sheet.

The Company has medium-term incentive plans under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Employee Post-Retirement Benefits

The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), 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 (EARSL) of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the EARSL of employees active at the date of amendment. The Company recognizes the overfunded or underfunded status of its DB Plans as an asset or liability, respectively, on its Consolidated balance sheet and recognizes changes in that funded status through Other comprehensive income (OCI) in the year in which the change occurs. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized out of Accumulated other comprehensive income (AOCI) and into net income over the EARSL of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

For certain regulated operations, post-retirement benefit amounts are recoverable through tolls as benefits are funded. The Company records any unrecognized gains or losses or changes in actuarial assumptions related to these post-retirement benefit plans as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the EARSL of active employees.

Foreign Currency Transactions and Translation

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or reporting subsidiary operates. This is referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are recorded in net income except for exchange gains and losses 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 CER.

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar reporting currency are reflected in OCI until the operations are sold, at which time the gains and losses are reclassified to net income. Asset and liability accounts are translated at the period-end exchange rates while revenues, expenses, gains and losses are translated at the exchange rates in effect at the time of the transaction. The Company's U.S. dollar-denominated debt and certain derivative hedging instruments have been designated as a hedge of the net investment in foreign subsidiaries and, as a result, the unrealized foreign exchange gains and losses on the U.S. dollar denominated debt are also reflected in OCI.

Derivative Instruments and Hedging Activities

All derivative instruments are recorded on the Consolidated balance sheet at fair value, unless they qualify for and are designated under a normal purchase and normal sales exemption, or are considered to meet other permitted exemptions.

The Company applies hedge accounting to arrangements that qualify for and are designated for hedge accounting treatment. This includes fair value and cash flow hedges and hedges of foreign currency exposures of net investments in foreign operations. Hedge accounting is discontinued prospectively if the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk and these changes are recognized in net income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in net income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in Interest income and other and Interest expense, respectively. If hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to net income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the change in the fair value of the hedging derivative is recognized in OCI. When hedge accounting is discontinued, the amounts recognized previously in AOCI are reclassified to Revenues, Interest expense and Interest income and other, as appropriate, during the periods when the variability in cash flows of the hedged item affects net income or as the original hedged item settles. Gains and losses on derivatives are reclassified immediately to net income from AOCI when the hedged item is sold or terminated early, or when it becomes probable that the anticipated transaction will not occur.

In hedging the foreign currency exposure of a net investment in a foreign operation, the foreign exchange gains and losses on the hedging instruments are recognized in OCI. The amounts recognized previously in AOCI are reclassified to net income in the event the Company reduces its net investment in a foreign operation.

In some cases, derivatives do not meet the specific criteria for hedge accounting treatment. In these instances, the changes in fair value are recorded in net income in the period of change.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipelines exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, are refunded or recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as regulatory assets or liabilities and are refunded to or collected from ratepayers in subsequent years when the derivative settles.

Derivatives embedded in other financial instruments or contracts (host instrument) are recorded as separate derivatives. Embedded derivatives are measured at fair value if their economic characteristics are not clearly and closely related to those of the host instrument, their terms are the same as those of a stand-alone derivative and the total contract is not held for trading or accounted for at fair value. When changes in the fair value of embedded derivatives are measured separately, they are included in net income.

Long-Term Debt Transaction Costs and Issuance Costs

The Company records long-term debt transaction costs and issuance costs as a deduction from the carrying amount of the related debt liability and amortizes these costs using the effective interest method for all costs except those related to the Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of regulatory tolling mechanisms.

Guarantees

Upon issuance, the Company records the fair value of certain guarantees entered into by the Company on behalf of a partially-owned entity or by partially-owned entities for which contingent payments may be made. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees as appropriate in the circumstances. Guarantees are recorded as an increase to Equity investments or Plant, property and equipment and a corresponding liability is recorded in Other long-term liabilities. The release from the obligation is recognized either over the term of the guarantee or upon expiration or settlement of the guarantee.

3. ACCOUNTING CHANGES

Changes in Accounting Policies for 2019

Leases

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

The new guidance was effective January 1, 2019 and was applied using optional transition relief which allowed entities to initially apply the new lease standard at adoption (January 1, 2019) and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. This transition option allowed the Company to not apply the new guidance, including disclosure requirements, to the comparative periods presented.

The Company elected available practical expedients and exemptions upon adoption which allowed the Company:

- to not reassess prior conclusions on existing leases regarding lease identification, lease classification and initial direct costs under the new standard
- to carry forward the historical lease classification and its accounting treatment for land easements on existing agreements
- to not recognize ROU assets or lease liabilities for leases that qualify for the short-term lease recognition exemption
- to not separate lease and non-lease components for all leases for which the Company is the lessee and for facility and liquids tank terminals for which the Company is the lessor
- to use hindsight in determining the lease term and assessing ROU assets for impairment.

The new guidance had a significant impact on the Company's Consolidated balance sheet, but did not have an impact in the Company's Consolidated statements of income and cash flows. The most impactful change was the recognition of ROU assets and lease liabilities for operating leases and providing additional new disclosures about the Company's leasing activities. Refer to Note 9, Leases, for additional information related to the impact of adopting the new guidance.

In the application of the new guidance, significant assumptions and judgments are used to determine the following:

- whether a contract contains a lease
- the duration of the lease term including exercising lease renewal options. The lease term for all of the Company's leases includes the noncancellable period of the lease plus any additional periods covered by either a Company option to extend (or not to terminate) the lease that the Company is reasonably certain to exercise, or an option to extend (or not to terminate) the lease controlled by the lessor
- the discount rate for the lease.

Lessee Accounting Policy

The Company determines if an arrangement is a lease at inception of the contract. Operating leases are recognized as ROU assets and included in Plant, property and equipment while corresponding liabilities are included in Accounts payable and other and Other long-term liabilities on the Consolidated balance sheet.

Operating lease ROU assets and operating lease liabilities are recognized based on the present value of the future minimum lease payments over the lease term at the commencement date of the lease agreement. As the Company's lease contracts do not provide an implicit interest rate, the Company uses its incremental borrowing rate based on the information available at commencement date in determining the present value of future payments. The operating lease ROU asset also includes any prepaid lease payments and initial direct costs incurred and excludes lease incentives. Lease terms may include options to extend or terminate the lease when it is reasonably certain that the Company will exercise that option. Operating lease expense is recognized on a straight-line basis over the lease term and included in Plant operating costs and other in the Consolidated statement of income.

Lessor Accounting Policy

The Company is the lessor within certain contracts and these are accounted for as operating leases. The Company recognizes lease payments as income over the lease term on a straight-line basis. Variable lease payments are recognized as income in the period in which the changes in facts and circumstances on which these payments are based occur.

Fair value measurement

In August 2018, the FASB issued new guidance that amends certain disclosure requirements for fair value measurements. This new guidance is effective January 1, 2020, however, early adoption of certain or all requirements is permitted. The Company elected to adopt this guidance effective first quarter 2019. The guidance was applied retrospectively and did not have a material impact on the Company's consolidated financial statements.

Future Accounting Changes

Measurement of credit losses on financial instruments

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

Implementation costs of cloud computing arrangements

In August 2018, the FASB issued new guidance requiring an entity in a hosting arrangement that is a service contract to follow the guidance for internal-use software to determine which implementation costs should be capitalized as an asset and which costs should be expensed. The guidance also requires the entity to amortize the capitalized implementation costs of a hosting arrangement over the term of the arrangement. This guidance is effective January 1, 2020 and will be applied prospectively to all implementation costs incurred after the date of adoption. The adoption of this new guidance will not have a material impact on the Company's consolidated financial statements.

Consolidation

In October 2018, the FASB issued new guidance for determining whether fees paid to decision makers and service providers are variable interests for indirect interests held through related parties under common control. This new guidance is effective January 1, 2020 and will be applied on a retrospective basis. The adoption of this new guidance will not have a material impact on the Company's consolidated financial statements.

Defined benefit plans

In August 2018, the FASB issued new guidance which amends and clarifies disclosure requirements related to defined benefit pension and other post-retirement benefit plans. This new guidance is effective for annual disclosure requirements at December 31, 2020 and is expected to be applied on a retrospective basis. The Company does not expect the adoption of this new guidance to have a material impact on its consolidated financial statements.

Income taxes

In December 2019, the FASB issued new guidance that simplified the accounting for income taxes and clarified existing guidance. This new guidance is effective January 1, 2021, however, early adoption is permitted. The Company is currently evaluating the timing and impact of the adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

4. SEGMENTED INFORMATION

year ended December 31, 2019 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Corporate[1]	Total
Revenues	**4,010**	**4,978**	**603**	**2,879**	**785**	**—**	**13,255**
Intersegment revenues	**—**	**164**	**—**	**—**	**19**	**(183)** [2]	**—**
	4,010	**5,142**	**603**	**2,879**	**804**	**(183)**	**13,255**
Income/(loss) from equity investments	**12**	**264**	**56**	**70**	**571**	**(53)** [3]	**920**
Plant operating costs and other	**(1,473)**	**(1,581)**	**(54)**	**(728)**	**(239)**	**166** [2]	**(3,909)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(369)**	**—**	**(369)**
Property taxes	**(275)**	**(345)**	**—**	**(101)**	**(6)**	**—**	**(727)**
Depreciation and amortization	**(1,159)**	**(754)**	**(115)**	**(341)**	**(95)**	**—**	**(2,464)**
Gain/(loss) on assets held for sale/sold	**—**	**21**	**—**	**69**	**(211)**	**—**	**(121)**
Segmented earnings/(losses)	**1,115**	**2,747**	**490**	**1,848**	**455**	**(70)**	**6,585**
Interest expense							**(2,333)**
Allowance for funds used during construction							**475**
Interest income and other[3]							**460**
Income before income taxes							**5,187**
Income tax expense							**(754)**
Net income							**4,433**
Net income attributable to non-controlling interests							**(293)**
Net income attributable to controlling interests							**4,140**
Preferred share dividends							**(164)**
Net income attributable to common shares							**3,976**
Capital spending							
Capital expenditures	**3,900**	**2,500**	**323**	**239**	**481**	**32**	**7,475**
Capital projects in development	**6**	**—**	**—**	**701**	**—**	**—**	**707**
Contributions to equity investments	**—**	**16**	**34**	**14**	**538**	**—**	**602**
	3,906	**2,516**	**357**	**954**	**1,019**	**32**	**8,784**

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Income/(loss) from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange losses on the peso-denominated loans from affiliates which are fully offset in Interest income and other. Refer to Note 10, Equity investments, for additional information.

year ended December 31, 2018 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Corporate[1]	Total
Revenues	4,038	4,314	619	2,584	2,124	—	13,679
Intersegment revenues	—	162	—	—	56	(218) [2]	—
	4,038	4,476	619	2,584	2,180	(218)	13,679
Income from equity investments	12	256	22	64	355	5 [3]	714
Plant operating costs and other	(1,405)	(1,368)	(34)	(630)	(313)	159 [2]	(3,591)
Commodity purchases resold	—	—	—	—	(1,488)	—	(1,488)
Property taxes	(266)	(199)	—	(98)	(6)	—	(569)
Depreciation and amortization	(1,129)	(664)	(97)	(341)	(119)	—	(2,350)
Goodwill and other asset impairment charges	—	(801)	—	—	—	—	(801)
Gain on sale of assets	—	—	—	—	170	—	170
Segmented earnings/(losses)	1,250	1,700	510	1,579	779	(54)	5,764
Interest expense							(2,265)
Allowance for funds used during construction							526
Interest income and other[3]							(76)
Income before income taxes							3,949
Income tax expense							(432)
Net income							3,517
Net loss attributable to non-controlling interests							185
Net income attributable to controlling interests							3,702
Preferred share dividends							(163)
Net income attributable to common shares							3,539
Capital spending							
Capital expenditures	2,442	5,591	463	110	767	45	9,418
Capital projects in development	36	1	—	459	—	—	496
Contributions to equity investments	—	179	334	12	490	—	1,015
	2,478	5,771	797	581	1,257	45	10,929

1 Includes intersegment eliminations.
2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.
3 Income from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange gains on the peso-denominated loans from affiliates which are fully offset in Interest income and other. Refer to Note 10, Equity investments, for additional information.

year ended December 31, 2017 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Corporate[1]	Total
Revenues	3,693	3,584	570	2,009	3,593	—	13,449
Intersegment revenues	—	51	—	—	—	(51) [2]	—
	3,693	3,635	570	2,009	3,593	(51)	13,449
Income/(loss) from equity investments	11	240	(9)	(3)	471	63 [3]	773
Plant operating costs and other	(1,300)	(1,340)	(42)	(623)	(550)	(51) [2]	(3,906)
Commodity purchases resold	—	—	—	—	(2,382)	—	(2,382)
Property taxes	(260)	(181)	—	(89)	(39)	—	(569)
Depreciation and amortization	(908)	(594)	(93)	(309)	(151)	—	(2,055)
Goodwill and other asset impairment charges	—	—	—	(1,236)	(21)	—	(1,257)
Gain on sale of assets	—	—	—	—	631	—	631
Segmented earnings/(losses)	1,236	1,760	426	(251)	1,552	(39)	4,684
Interest expense							(2,069)
Allowance for funds used during construction							507
Interest income and other[3]							184
Income before income taxes							3,306
Income tax recovery							89
Net income							3,395
Net income attributable to non-controlling interests							(238)
Net income attributable to controlling interests							3,157
Preferred share dividends							(160)
Net income attributable to common shares							2,997
Capital spending							
Capital expenditures	2,106	3,712	833	341	350	41	7,383
Capital projects in development	75	—	—	71	—	—	146
Contributions to equity investments	—	118	1,121	117	325	—	1,681
	2,181	3,830	1,954	529	675	41	9,210

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Income/(loss) from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange gains on the peso-denominated loans from affiliates which are fully offset in Interest income and other. Refer to Note 10, Equity investments, for additional information.

at December 31 (millions of Canadian $)	2019	2018
Total Assets by segment		
Canadian Natural Gas Pipelines	**21,983**	18,407
U.S. Natural Gas Pipelines	**41,627**	44,115
Mexico Natural Gas Pipelines	**7,207**	7,058
Liquids Pipelines	**15,931**	17,352
Power and Storage	**7,788**	8,475
Corporate	**4,743**	3,513
	99,279	98,920

Geographic Information

year ended December 31 (millions of Canadian $)	2019	2018	2017
Revenues			
Canada – domestic	**4,059**	4,187	3,618
Canada – export	**1,035**	1,075	1,255
United States	**7,558**	7,798	8,006
Mexico	**603**	619	570
	13,255	13,679	13,449

at December 31 (millions of Canadian $)	2019	2018
Plant, Property and Equipment		
Canada	**23,362**	23,226
United States	**36,184**	37,385
Mexico	**5,943**	5,892
	65,489	66,503

5. REVENUES

On January 1, 2018, the Company adopted new FASB guidance on revenue from contracts with customers using the modified retrospective transition method for all contracts that were in effect on the date of adoption. Results reported for 2019 and 2018 reflect the application of the new guidance, while the 2017 comparative results were prepared and reported under previous revenue recognition guidance.

Disaggregation of Revenues

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

1 Other revenues include income from the Company's marketing activities, financial instruments and lease contracts. These arrangements are not in the scope of the revenue guidance. Refer to Note 9, Leases, and Note 25, Risk management and financial instruments, for additional information on income from lease arrangements and financial instruments, respectively.

2 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from U.S. Tax Reform. Refer to Note 17, Income taxes, for additional information.

year ended December 31, 2018 (millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Power and Storage**	**Total**
Revenues from contracts with customers						
Capacity arrangements and transportation	4,038	3,549	614	2,079	—	10,280
Power generation	—	—	—	—	1,771	1,771
Natural gas storage and other	—	654	5	3	81	743
	4,038	4,203	619	2,082	1,852	12,794
Other revenues[1,2]	—	111	—	502	272	885
	4,038	4,314	619	2,584	2,124	13,679

1 Other revenues include income from the Company's marketing activities, financial instruments and lease contracts. These arrangements are not in the scope of the revenue guidance. Refer to Note 25, Risk management and financial instruments, for additional information on income from financial instruments.

2 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from U.S. Tax Reform. Refer to Note 17, Income taxes, for additional information.

Revenues from contracts with customers are recognized net of any taxes collected from customers which are subsequently remitted to governmental authorities. The Company's contracts with customers include natural gas and liquids pipelines capacity arrangements and transportation contracts, power generation contracts, natural gas storage and other contracts.

Contract Balances

at December 31 (millions of Canadian $)	2019	2018
Receivables from contracts with customers	**1,458**	1,684
Contract assets (Note 7)	**153**	159
Long-term contract assets[1]	**102**	21
Contract liabilities[2]	**61**	11
Long-term contract liabilities (Note 16)	**226**	121

1 Recorded as part of Intangibles and other assets on the Consolidated balance sheet.

2 Comprised of deferred revenue recorded in Accounts payable and other on the Consolidated balance sheet. During the year ended December 31, 2019, $6 million (2018 – $17 million) of revenue was recognized that was included in the contract liability at the beginning of the year.

Contract assets and long-term contract assets primarily relate to the Company's right to revenues for services completed but not invoiced at the reporting date on long-term committed capacity natural gas pipelines contracts. The change in contract assets is primarily related to the transfer to Accounts receivable when these rights become unconditional and the customer is invoiced, as well as the recognition of additional revenues that remain to be invoiced. Contract liabilities and long-term contract liabilities primarily relate to force majeure fixed capacity payments received on long-term capacity arrangements in Mexico.

Future Revenues from Remaining Performance Obligations

The following provides a discussion of the transaction price allocated to future performance obligations as well as practical expedients used by the Company.

Capacity Arrangements and Transportation

As at December 31, 2019, future revenues from long-term pipeline capacity arrangements and transportation contracts extending through 2046 are approximately $26.6 billion, of which approximately $3.7 billion is expected to be recognized in 2020.

Future revenues from long-term capacity arrangements and transportation contracts do not include constrained variable revenues or arrangements to which the right to invoice practical expedient has been applied. As a result, these amounts are not representative of potential total future revenues expected from these contracts.

Future revenues from the Company's Canadian natural gas pipelines' regulated firm capacity contracts include fixed revenues for the time periods that tolls under current rate settlements are in effect, which is currently one year. Many of these contracts are long-term in nature and revenues from the remaining performance obligations that extend beyond the current rate settlement term are considered to be fully constrained since future tolls remain unknown. Revenues from these contracts will be recognized once the performance obligation to provide capacity has been satisfied and the regulator has approved the applicable tolls. In addition, the Company considers interruptible transportation service revenues to be variable revenues since volumes cannot be estimated. These variable revenues are recognized on a monthly basis when the Company satisfies the performance obligation and have been excluded from the future revenues disclosure as the Company applies the practical expedient related to variable revenues to these contracts. The future variable revenues earned under these contracts are allocated entirely to unsatisfied performance obligations at December 31, 2019.

The Company also applies the right to invoice practical expedient to all of its U.S. and certain of its Mexico regulated natural gas pipeline capacity arrangements and flow-through revenues. Revenues from regulated capacity arrangements are recognized based on current rates and flow-through revenues are earned from the recovery of operating expenses. These revenues are recognized on a monthly basis as the Company performs the services and are excluded from future revenues disclosures.

Revenues from liquids pipelines capacity arrangements have a variable component based on volumes transported. As a result, these variable revenues are excluded from the future revenues disclosures as the Company applies the practical expedient related to variable revenues to these contracts. The future variable revenues earned under these contracts are allocated entirely to unsatisfied performance obligations at December 31, 2019.

Power Generation

The Company has long-term power generation contracts extending through 2028. Revenues from power generation have a variable component related to market prices that are subject to factors outside the Company's influence. These revenues are considered to be fully constrained and are recognized on a monthly basis when the Company satisfies the performance obligation. The Company applies the practical expedient related to variable revenues to these contracts. As a result, future revenues from these contracts are excluded from the disclosures.

Natural Gas Storage and Other

As at December 31, 2019, future revenues from long-term natural gas storage and other contracts extending through 2026 are approximately $0.8 billion, of which approximately $414 million is expected to be recognized in 2020. The Company applies the practical expedients related to contracts that are for a duration of one year or less and where it recognizes variable consideration, and therefore excludes the related revenues from the future revenues disclosure. As a result, these amounts are lower than the potential total future revenues from these contracts.

6. ASSETS HELD FOR SALE

Ontario Natural Gas-Fired Power Plants

On July 30, 2019, TC Energy entered into an agreement to sell the Halton Hills and Napanee power plants as well as its 50 per cent interest in Portlands Energy Centre to a third party for proceeds of approximately $2.87 billion, subject to timing of the close and related adjustments. The sale is expected to close by the end of first quarter 2020 subject to conditions which include regulatory approvals and Napanee completing construction and reaching commercial operations as outlined in the agreement. TC Energy expects this sale to result in a total pre-tax loss of approximately $380 million ($280 million after tax), with $279 million of the pre-tax loss ($194 million after tax) recorded at December 31, 2019 after classifying the net assets as held for sale. The remaining loss will be recorded on or before closing of the transaction.

At December 31, 2019, the related assets and liabilities in the Power and Storage segment were classified as held for sale as follows:

(millions of Canadian $)	
Assets held for sale	
Inventories	**11**
Other current assets	**3**
Plant, property and equipment	**2,502**
Equity investments	**276**
Intangible and other assets	**15**
Total assets held for sale	**2,807**
Liabilities related to assets held for sale	
Other long-term liabilities	**8**
Total liabilities related to assets held for sale[1]	**8**

1 Included in Accounts payable and other on the Consolidated balance sheet.

Coolidge Generating Station

On May 21, 2019, TC Energy completed the sale of its Coolidge generating station, which was reported as Assets held for sale at December 31, 2018. Refer to Note 27, Acquisitions and dispositions, for additional information.

7. OTHER CURRENT ASSETS

at December 31 (millions of Canadian $)	2019	2018
Fair value of derivative contracts (Note 25)	**190**	737
Contract assets (Note 5)	**153**	159
Prepaid expenses	**60**	41
Cash provided as collateral	**52**	55
Regulatory assets (Note 11)	**43**	83
Other	**129**	105
	627	1,180

8. PLANT, PROPERTY AND EQUIPMENT

at December 31 (millions of Canadian $)	2019 Cost	2019 Accumulated Depreciation	2019 Net Book Value	2018 Cost	2018 Accumulated Depreciation	2018 Net Book Value
Canadian Natural Gas Pipelines						
NGTL System						
Pipeline	**11,556**	**4,846**	**6,710**	10,764	4,500	6,264
Compression	**4,205**	**1,771**	**2,434**	3,289	1,677	1,612
Metering and other	**1,296**	**609**	**687**	1,247	613	634
	17,057	**7,226**	**9,831**	15,300	6,790	8,510
Under construction	**3,181**	**—**	**3,181**	2,111	—	2,111
	20,238	**7,226**	**13,012**	17,411	6,790	10,621
Canadian Mainline						
Pipeline	**10,145**	**7,109**	**3,036**	10,077	6,777	3,300
Compression	**3,867**	**2,823**	**1,044**	3,642	2,656	986
Metering and other	**643**	**219**	**424**	652	241	411
	14,655	**10,151**	**4,504**	14,371	9,674	4,697
Under construction	**60**	**—**	**60**	149	—	149
	14,715	**10,151**	**4,564**	14,520	9,674	4,846
Other Canadian Natural Gas Pipelines[1]						
Other	**1,861**	**1,455**	**406**	1,842	1,420	422
Under construction	**1,276**	**—**	**1,276**	124	—	124
	3,137	**1,455**	**1,682**	1,966	1,420	546
	38,090	**18,832**	**19,258**	33,897	17,884	16,013
U.S. Natural Gas Pipelines						
Columbia Gas						
Pipeline	**9,708**	**389**	**9,319**	6,711	251	6,460
Compression	**4,094**	**206**	**3,888**	2,932	132	2,800
Metering and other	**3,244**	**125**	**3,119**	2,884	75	2,809
	17,046	**720**	**16,326**	12,527	458	12,069
Under construction	**425**	**—**	**425**	4,347	—	4,347
	17,471	**720**	**16,751**	16,874	458	16,416
ANR						
Pipeline	**1,594**	**472**	**1,122**	1,600	443	1,157
Compression	**2,050**	**436**	**1,614**	1,978	388	1,590
Metering and other	**1,245**	**355**	**890**	1,217	324	893
	4,889	**1,263**	**3,626**	4,795	1,155	3,640
Under construction	**252**	**—**	**252**	272	—	272
	5,141	**1,263**	**3,878**	5,067	1,155	3,912

at December 31 (millions of Canadian $)	2019 Cost	2019 Accumulated Depreciation	2019 Net Book Value	2018 Cost	2018 Accumulated Depreciation	2018 Net Book Value
Other U.S. Natural Gas Pipelines						
GTN	**2,257**	**969**	**1,288**	2,322	951	1,371
Great Lakes	**2,090**	**1,208**	**882**	2,180	1,251	929
Columbia Gulf	**2,597**	**114**	**2,483**	1,753	74	1,679
Midstream[2]	**302**	**42**	**260**	1,212	91	1,121
Other[3]	**1,228**	**574**	**654**	1,190	474	716
	8,474	**2,907**	**5,567**	8,657	2,841	5,816
Under construction	**164**	**—**	**164**	846	—	846
	8,638	**2,907**	**5,731**	9,503	2,841	6,662
	31,250	**4,890**	**26,360**	31,444	4,454	26,990
Mexico Natural Gas Pipelines						
Pipeline	**2,988**	**340**	**2,648**	3,172	301	2,871
Compression	**486**	**54**	**432**	506	41	465
Metering and other	**643**	**124**	**519**	640	91	549
	4,117	**518**	**3,599**	4,318	433	3,885
Under construction	**2,321**	**—**	**2,321**	1,990	—	1,990
	6,438	**518**	**5,920**	6,308	433	5,875
Liquids Pipelines						
Keystone Pipeline System						
Pipeline	**9,378**	**1,403**	**7,975**	9,780	1,271	8,509
Pumping equipment	**1,035**	**204**	**831**	1,065	184	881
Tanks and other	**3,488**	**556**	**2,932**	3,598	488	3,110
	13,901	**2,163**	**11,738**	14,443	1,943	12,500
Under construction	**47**	**—**	**47**	18	—	18
	13,948	**2,163**	**11,785**	14,461	1,943	12,518
Intra-Alberta Pipelines[4]						
Pipeline	**138**	**2**	**136**	762	22	740
Pumping equipment	**—**	**—**	**—**	104	3	101
Tanks and other	**56**	**2**	**54**	291	8	283
	194	**4**	**190**	1,157	33	1,124
Under construction	**—**	**—**	**—**	84	—	84
	194	**4**	**190**	1,241	33	1,208
	14,142	**2,167**	**11,975**	15,702	1,976	13,726
Power and Storage						
Natural Gas[5,6]	**1,256**	**522**	**734**	2,062	708	1,354
Natural Gas Storage and Other	**742**	**181**	**561**	741	169	572
	1,998	**703**	**1,295**	2,803	877	1,926
Under construction[6]	**6**	**—**	**6**	1,735	—	1,735
	2,004	**703**	**1,301**	4,538	877	3,661
Corporate	**883**	**208**	**675**	448	210	238
	92,807	**27,318**	**65,489**	92,337	25,834	66,503

1 Includes Foothills, Ventures LP, Great Lakes Canada and Coastal GasLink.
2 The Company completed the sale of certain Columbia midstream assets on August 1, 2019. Refer to Note 27, Acquisitions and dispositions, for additional information.
3 Includes Portland, North Baja, Tuscarora and Crossroads.
4 The Company completed the sale of an 85 per cent equity interest in Northern Courier on July 17, 2019 and recorded its remaining 15 per cent interest as an equity investment. Refer to Note 10, Equity Investments, and Note 27, Acquisitions and dispositions, for additional information.
5 Includes Grandview, Bécancour and the Alberta cogeneration natural gas-fired facilities at December 31, 2019.
6 The Company completed the sale of the Coolidge generating station on May 21, 2019. Refer to Note 27, Acquisition and dispositions, for additional information. At July 30, 2019, the cost and accumulated depreciation of the Halton Hills and Napanee power plants were reclassified as Assets held for sale. Refer to Note 6, Assets held for sale, for additional information.

Coastal GasLink

In December 2019, TC Energy entered into an agreement to sell a 65 per cent equity interest in Coastal GasLink to KKR-Keats Pipeline Investors II (Canada) Ltd. (KKR) and a subsidiary of Alberta Investment Management Corporation (AIMCo), which is expected to close in the first half of 2020.

In conjunction with this sale, the Company will provide an option to the 20 First Nations that have executed agreements with Coastal GasLink to acquire a 10 per cent equity interest in Coastal GasLink on similar terms to what has been agreed with KKR and AIMCo.

Bison Impairment

At December 31, 2018, the Company evaluated its investment in its Bison natural gas pipeline for impairment in connection with the termination of certain customer transportation agreements. The termination of these agreements released the Company from providing any future services. With the loss of these future cash flows and the persistence of unfavourable market conditions which have inhibited system flows on the pipeline, the Company determined that the asset's remaining carrying value was no longer recoverable and recognized a non-cash impairment charge of $722 million pre tax in its U.S. Natural Gas Pipelines segment. The non-cash charge was recorded in Goodwill and other asset impairment charges in the Consolidated statement of income. As Bison is a TC PipeLines, LP asset, in which the Company had a 25.5 per cent interest, the Company's share of the impairment charge, after tax and net of non-controlling interests, was $140 million.

The termination of the transportation agreements resulted in the receipt of $130 million in termination payments which were recorded in Revenues in 2018. The Company's share of this amount, after tax and net of non-controlling interests, was $25 million.

Energy East and Related Projects Impairment

In October 2017, the Company informed the NEB that it would 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 in the Consolidated statement of income.

Energy Turbine Impairment

At December 31, 2017, the Company recognized a non-cash impairment charge of $21 million ($16 million after tax) in the Power and Storage segment related to the remaining carrying value of certain equipment after determining that it was no longer recoverable. This turbine equipment was previously purchased for a power development project that did not proceed. The non-cash charge was recorded in Goodwill and other asset impairment charges in the Consolidated statement of income.

9. LEASES

On January 1, 2019, the Company adopted the FASB's new lease guidance using optional transition relief. Results reported for 2019 reflect the application of the new guidance while the 2018 and 2017 comparative results were prepared and reported under previous leases guidance.

Impact of New Lease Guidance on Date of Adoption

The following table illustrates the impact of the adoption of the new lease guidance on the Company's previously reported Consolidated balance sheet line items:

(millions of Canadian $)	As reported December 31, 2018	Adjustment	January 1, 2019
Plant, property and equipment	66,503	585	67,088
Accounts payable and other	5,408	57	5,465
Other long-term liabilities	1,008	528	1,536

As a Lessee

The Company has operating leases for corporate offices, other various premises, equipment and land. Some leases have an option to renew for periods of one to 25 years, and some may include options to terminate the lease within one year. Payments due under lease contracts include fixed payments plus, for many of the Company's leases, variable payments such as a proportionate share of the buildings' property taxes, insurance and common area maintenance. The Company subleases some of the leased premises.

Operating lease cost is as follows:

year ended December 31 (millions of Canadian $)	**2019**
Operating lease cost[1]	**117**
Sublease income	**(11)**
Net operating lease cost	**106**

1 Includes short-term leases and variable lease costs.

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

year ended December 31 (millions of Canadian $)	**2019**
Cash paid for amounts included in the measurement of operating lease liabilities	**76**
ROU assets obtained in exchange for new operating lease liabilities	**9**

at December 31	**2019**
Weighted average remaining lease term	**10 years**
Weighted average discount rate	**3.5%**

Maturities of operating lease liabilities and where they are disclosed on the Consolidated balance sheet as at December 31, 2019 are as follows:

(millions of Canadian $)	
2020	**73**
2021	**69**
2022	**59**
2023	**58**
2024	**57**
Thereafter	**323**
Total operating lease payments	**639**
Imputed interest	**(107)**
Operating lease liabilities	**532**

The amounts recognized on TC Energy's Consolidated balance sheet for its operating lease liabilities as at December 31, 2019 are reported as follows:

(millions of Canadian $)	
Accounts payable and other	**56**
Other long-term liabilities (Note 16)	**476**
	532

Future payments reported under previous lease guidance for the Company's operating leases as at December 31, 2018 were as follows:

(millions of Canadian $)	**Minimum operating lease payments**
2019	81
2020	78
2021	76
2022	69
2023	67
Thereafter	390
	761

As at December 31, 2019, the carrying value of the ROU assets recorded under operating leases was $530 million and is included in Plant, property and equipment on the Consolidated balance sheet.

Net rental expense on operating leases in 2018 and 2017 was $84 million and $93 million, respectively.

As a Lessor

The Grandview and Bécancour power plants in the Power and Storage segment are accounted for as operating leases. In addition, the Company has long-term PPAs for the sale of power for the Power and Storage lease assets which expire between 2024 and 2026.

The Northern Courier pipeline in the Liquids Pipelines segment is accounted for as an operating lease and has a liquids transportation contract expiring in 2042. On July 17, 2019, TC Energy completed the sale of an 85 per cent equity interest in Northern Courier and now uses the equity method to account for its remaining 15 per cent interest in the Company's consolidated financial statements. Refer to Note 27, Acquisitions and dispositions, for additional information. As a result, only the operating lease income prior to this sale has been included in this lease disclosure.

Some leases contain variable lease payments that are based on operating hours and the reimbursement of variable costs, and options to purchase the underlying asset at fair value or based on a formula considering the remaining fixed payments. Lessees have rights under some leases to terminate under certain circumstances.

The Company also leases liquids tanks which are accounted for as operating leases.

The fixed portion of the operating lease income recorded by the Company for the year ended December 31, 2019 was $180 million. Operating lease income in 2018 and 2017 was $373 million and $251 million, respectively.

Future lease payments to be received under operating leases as at December 31, 2019 are as follows:

(millions of Canadian $)	**Future lease payments**
2020	**123**
2021	**116**
2022	**111**
2023	**109**
2024	**109**
Thereafter	**164**
	732

The cost and accumulated depreciation for facilities accounted for as operating leases was $834 million and $301 million, respectively, at December 31, 2019 (2018 – $2,007 million and $324 million, respectively).

10. EQUITY INVESTMENTS

(millions of Canadian $)	Ownership Interest at December 31, 2019	Income/(Loss) from Equity Investments year ended December 31 2019	2018	2017	Equity Investments at December 31 2019	2018
Canadian Natural Gas Pipelines						
TQM	50.0%	**12**	12	11	**79**	71
U.S. Natural Gas Pipelines						
Northern Border[1]	50.0%	**91**	87	87	**549**	677
Millennium	47.5%	**92**	75	66	**496**	511
Iroquois[2]	50.0%	**54**	60	59	**241**	291
Pennant Midstream[3]	nil	**12**	17	11	**—**	256
Other	Various	**15**	17	17	**112**	113
Mexico Natural Gas Pipelines						
Sur de Texas[4]	60.0%	**3**	27	66	**600**	627
TransGas	nil	**—**	—	(12)	**—**	—
Liquids Pipelines						
Grand Rapids[5]	50.0%	**56**	65	17	**1,028**	1,028
Northern Courier[6]	15.0%	**14**	—	—	**62**	—
Other[7]	Various	**—**	(1)	(20)	**19**	21
Power and Storage						
Bruce Power[8]	48.4%	**527**	311	434	**3,256**	3,166
Portlands Energy Centre[9]	50.0%	**35**	36	31	**—**	289
TransCanada Turbines	50.0%	**9**	8	6	**64**	63
		920	714	773	**6,506**	7,113

1 At December 31, 2019, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Border Pipeline Company was US$116 million (2018 – US$115 million) due mainly to the fair value assessment of assets at the time of acquisition.

2 At December 31, 2019, the difference between the carrying value of the investment and the underlying equity in the net assets of Iroquois was US$40 million (2018 – US$41 million) due mainly to the fair value assessment of the assets at the time of acquisitions.

3 On August 1, 2019, TC Energy completed the sale of certain Columbia midstream assets, including the Company's investment in Pennant Midstream, to a third party. Refer to Note 27, Acquisitions and dispositions, for additional information.

4 TC Energy has a 60 per cent ownership interest in Sur de Texas which, as a jointly controlled entity, applies the equity method of accounting. Income from equity investments recorded in the Corporate segment reflects the Company's proportionate share of Sur de Texas foreign exchange gains and losses on the peso-denominated loans from affiliates which are fully offset in Interest income and other in the Consolidated statement of income. Sur de Texas was placed into service in September 2019.

5 At December 31, 2019, the difference between the carrying value of the investment and the underlying equity in the net assets of Grand Rapids was $101 million (2018 – $102 million) due mainly to interest capitalized during construction and the fair value of guarantees. Grand Rapids was placed in service in August 2017.

6 On July 17, 2019, TC Energy completed the sale of an 85 per cent equity interest in Northern Courier, and it now applies the equity method to account for its 15 per cent retained equity interest in the jointly controlled entity. Refer to Note 27, Acquisitions and dispositions, for additional information.
At December 31, 2019, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Courier was $62 million due mainly to the fair value of guarantees and the fair value assessment of assets at the time of partial monetization.

7 Includes investments in HoustonLink Pipeline Company LLC and Canaport Energy East Marine Terminal Limited Partnership. At December 31, 2019 and 2018, the Canaport Energy East Marine Terminal Limited Partnership investment was nil.

8 At December 31, 2019, the difference between the carrying value of the investment and the underlying equity in the net assets of Bruce Power was $829 million (2018 – $870 million) due mainly to capitalized interest and the fair value assessment of assets at the time of acquisitions.

9 Investment in Portlands Energy Centre was reclassed to Assets held for sale following an agreement effective July 30, 2019 to sell the investment to a third party. Refer to Note 6, Assets held for sale, for additional information. At December 31, 2019, the difference between the carrying value of the investment and the underlying equity in the net assets of Portlands Energy Centre was $76 million (2018 – $73 million) due mainly to capitalized interest.

TransGas de Occidente S.A. Impairment

In August 2017, TC Energy recognized an impairment charge of $12 million on its 46.5 per cent equity investment in TransGas de Occidente S.A. (TransGas). TransGas constructed and operated a natural gas pipeline in Colombia for a 20-year contract term. As per the terms of the agreement, upon completion of the 20-year contract in August 2017, TransGas transferred its pipeline assets to Transportadora de Gas Internacional S.A. The non-cash impairment charge represented the write-down of the remaining carrying value of the equity investment which was recognized in Income from equity investments in the Consolidated statement of income in the Mexico Natural Gas Pipelines segment.

Canaport Energy East Marine Terminal Limited Partnership Impairment

In October 2017, the Company informed the NEB that it would not be proceeding with the Energy East, Eastern Mainline and Upland projects. As a result, in October 2017, the Company recognized a non-cash impairment charge of $20 million in Income from equity investments in its Liquids Pipelines segment which represented the total carrying value of the equity investment in the Canaport Energy East Marine Terminal Limited Partnership.

Distributions and Contributions

Distributions received from equity investments for the year ended December 31, 2019 were $1,399 million (2018 – $1,106 million; 2017 – $1,332 million), of which $186 million (2018 – $121 million; 2017 – $362 million) was included in Investing activities in the Consolidated statement of cash flows with respect to distributions received from Bruce Power and Northern Border from their respective financing programs.

Contributions made to equity investments for the year ended December 31, 2019 were $602 million (2018 – $1,015 million; 2017 – $1,681 million) and are included in Investing activities in the Consolidated statement of cash flows. For 2019, contributions include $32 million (2018 – $179 million; 2017 – $977 million) related to TC Energy's proportionate share of the Sur de Texas debt financing requirements.

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian $)	2019	2018	2017
Income			
Revenues	**5,693**	4,836	4,913
Operating and other expenses	**(3,408)**	(3,545)	(2,993)
Net income	**1,990**	1,515	1,636
Net income attributable to TC Energy	**920**	714	773

at December 31 (millions of Canadian $)	2019	2018
Balance Sheet		
Current assets	**2,305**	2,209
Non-current assets	**21,865**	20,647
Current liabilities	**(2,060)**	(2,049)
Non-current liabilities	**(11,461)**	(9,042)

Loan receivable from affiliate

TC Energy holds a 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline. In 2017, TC Energy entered into a MXN 21.3 billion unsecured revolving credit facility with the joint venture, which bears interest at a floating rate and matures in March 2022. At December 31, 2019, the Company's Consolidated balance sheet included a MXN 20.9 billion or $1.4 billion (2018 – MXN 18.9 billion or $1.3 billion) loan receivable from the Sur de Texas joint venture which represents TC Energy's proportionate share of long-term debt financing to the joint venture. Interest income and other included interest income of $147 million in 2019 (2018 – $120 million; 2017 – $34 million) from this joint venture with a corresponding proportionate share of interest expense recorded in Income from equity investments in the Mexico Natural Gas Pipelines segment. Interest income and other also included foreign exchange gains of $53 million in 2019 (2018 – losses of $5 million; 2017 – losses of $63 million) from this joint venture with a corresponding proportionate share of Sur de Texas foreign exchange gains and losses recorded in Income from equity investments in the Corporate segment.

11. RATE-REGULATED BUSINESSES

TC Energy's businesses that apply RRA currently include almost all of the Canadian, U.S. and Mexico natural gas pipelines and 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 recovered from or refunded to customers in future service rates.

Canadian Regulated Operations

The majority of TC Energy's Canadian natural gas pipelines were regulated by the NEB under the National Energy Board Act (NEB Act) up to August 28, 2019 when the Canadian Energy Regulator Act (CER Act) came into effect, replacing the NEB Act, and the NEB was replaced by the CER. The impact assessment and decision-making for designated major transboundary pipeline projects also changed with the implementation of the new Impact Assessment Act (IA Act) on August 28, 2019, which requires designated projects to be assessed by the Impact Assessment Agency of Canada, formerly the Canadian Environmental Assessment Agency. All TC Energy projects submitted to the NEB for review prior to August 28, 2019 will continue to be assessed under the previous NEB Act in accordance with the transitional rules under the CER Act.

The CER regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's Canadian regulated natural gas transmission systems under federal jurisdiction.

TC Energy's Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and return on capital as approved by the NEB or CER. Rates charged for these services are typically set through a process that involves filing an application with the regulator wherein forecasted operating costs, including a return of and on capital, determine the revenue requirement for the upcoming year or multiple years. To the extent actual costs and revenues are more or less than forecasted costs and revenues, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Differences between actual and forecasted costs that the regulator does not allow to be deferred are included in the determination of net income in the year they occur. The Company's most significant regulated Canadian natural gas pipelines, based on total operated pipe length, are described below.

NGTL System

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

Canadian Mainline

The Canadian Mainline currently operates under the terms of the 2015-2030 Tolls Application approved in 2014 (the NEB 2014 Decision). The terms 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 TC Energy contribution to reduce the revenue requirement. Toll stabilization is achieved through the use of deferral accounts, namely the bridging amortization account and the long-term adjustment account (LTAA), to capture the surplus or shortfall between the Company's revenues and cost of service for each year over the 2015-2020 six-year fixed toll term of the NEB 2014 Decision. The NEB 2014 Decision also directed

TC Energy to file an application to review tolls for the 2018-2020 period. In December 2018, an NEB decision was received on the 2018-2020 Tolls Review (NEB 2018 Decision) which included an accelerated amortization of the December 31, 2017 LTAA balance and an increase to the composite depreciation rate from 3.2 per cent to 3.9 per cent.

U.S. Regulated Operations

TC Energy's U.S. regulated natural gas pipelines operate under the provisions of the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 (NGA) and the Energy Policy Act of 2005, and are subject to the jurisdiction of the FERC. The NGA grants the FERC authority over the construction and operation of pipelines and related facilities, including the regulation of tariffs which incorporates maximum and minimum rates for services and allows U.S. regulated natural gas pipelines to discount or negotiate rates on a non-discriminatory basis. The Company's most significant regulated U.S. natural gas pipelines, based on effective ownership and total operated pipe length, are described below.

In 2018, FERC prescribed changes (2018 FERC Actions) related to H.R.1, the Tax Cuts and Jobs Act (U.S. Tax Reform), and income taxes for rate-making purposes in a master limited partnership (MLP) that impact future earnings and cash flows of FERC-regulated pipelines. FERC issued a Revised Policy Statement which created a presumption that entities whose earnings are not taxed through a corporation should not be permitted to recover an income tax allowance in their cost-of-service rates. In addition, FERC established that, to the extent an entity's income tax allowance should be eliminated from rates, it must also eliminate existing accumulated deferred income tax (ADIT) asset and liability balances from rate base.

These 2018 FERC Actions also established a process and schedule by which all FERC-regulated interstate pipelines and natural gas storage facilities had to either (i) file a new uncontested rate settlement or (ii) file a FERC Form 501-G that quantified the isolated impact of U.S. Tax Reform and provided four options to address the impact for rate-making purposes.

Columbia Gas

Columbia Gas' natural gas transportation and storage services are provided under a tariff at rates subject to FERC approval. A FERC-approved modernization settlement provided for cost recovery and return on investment of up to US$1.5 billion from 2013-2017 to modernize the Columbia Gas system thereby improving system integrity and enhancing service reliability and flexibility. An extension of this settlement was approved by the FERC in 2016 which allows 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

ANR Pipeline operates under rates established through a FERC-approved rate settlement in 2016. Under terms of the 2016 settlement, neither ANR Pipeline nor the settling parties could file for new rates to become effective earlier than August 1, 2019. However, ANR Pipeline is required to file for new rates to be effective no later than August 1, 2022.

Columbia Gulf

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

TC PipeLines, LP

TC Energy owns a 25.5 per cent interest in TC PipeLines, LP, which has ownership interests in eight wholly-owned or partially-owned natural gas pipelines serving major markets in the U.S. As TC PipeLines, LP is an MLP, all pipelines it owns wholly or in part were impacted by the 2018 FERC Actions which required these pipelines to eliminate their existing ADIT balance from rate base. Refer to Note 17, Income taxes, for additional information regarding the impact of these changes to TC Energy.

Great Lakes

Great Lakes reached a rate settlement with its customers, which was approved by FERC in February 2018, decreasing Great Lakes' maximum transportation rates by 27 per cent effective October 2017. This settlement does not contain a moratorium and Great Lakes will be required to file for new rates no later than March 31, 2022, with new rates to be effective October 1, 2022. In 2018, as a result of the 2018 FERC Actions noted above, Great Lakes made a limited Section 4 filing which had the effect of reducing rates by two per cent from what was in place previously. The reduction in rates became effective on February 1, 2019 after the limited Section 4 filing was accepted by FERC.

Mexico Regulated Operations

TC Energy's Mexico natural gas pipelines are regulated by the CRE and operate in accordance with CRE-approved tariffs. The rates in effect on TC Energy's Mexico natural gas pipelines were established based on CRE-approved contracts that provide for cost recovery, including a return of and on invested capital.

Regulatory Assets and Liabilities

at December 31 (millions of Canadian $)	2019	2018	Remaining Recovery/ Settlement Period (years)
Regulatory Assets			
Deferred income taxes[1]	**1,088**	1,051	n/a
Operating and debt-service regulatory assets[2]	**2**	12	1
Pensions and other post-retirement benefits[1,3]	**417**	379	n/a
Foreign exchange on long-term debt[1,4]	**16**	46	1-10
Other	**107**	143	n/a
	1,630	1,631	
Less: Current portion included in Other current assets (Note 7)	**43**	83	
	1,587	1,548	
Regulatory Liabilities			
Operating and debt-service regulatory liabilities[2]	**139**	96	1
Pensions and other post-retirement benefits[3]	**35**	53	n/a
ANR related post-employment and retirement benefits other than pension[5]	**41**	54	n/a
Long-term adjustment account[6]	**660**	1,015	1-47
Bridging amortization account[6]	**428**	305	11
Pipeline abandonment trust balance[7]	**1,462**	1,113	n/a
Cost of removal[8]	**253**	261	n/a
Deferred income taxes[1]	**151**	165	n/a
Deferred income taxes – U.S. Tax Reform[9]	**1,239**	1,394	n/a
Other	**60**	65	n/a
	4,468	4,521	
Less: Current portion included in Accounts payable and other (Note 15)	**696**	591	
	3,772	3,930	

1 These regulatory assets or liabilities are underpinned by non-cash transactions or are recovered without an allowance for return as approved by the regulator. Accordingly, these regulatory assets or liabilities are not included in rate base and do not yield a return on investment during the recovery period.

2 Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances to be included in determination of tolls in the following year.

3 These balances represent the regulatory offset to pension plan and other post-retirement obligations to the extent the amounts are expected to be collected from or refunded to customers in future rates.

4 Foreign exchange on long-term debt of the NGTL System represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate at the time of issue. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls.

5 This balance represents the amount ANR estimates it would be required to refund to its customers for post-retirement and post-employment benefit amounts collected through its FERC-approved rates that have not been used to pay benefits to its employees. Pursuant to a FERC-approved rate settlement, $11 million (US$8 million) of the regulatory liability balance at December 31, 2018 (which accumulated between January 2007 and July 2016) was fully amortized at July 31, 2019. The remaining $41 million (US$32 million) balance at December 31, 2019 which was accumulated prior to 2007 is subject to resolution through future regulatory proceedings and, accordingly, a settlement period cannot be determined at this time.

6 These regulatory accounts are used to capture Canadian Mainline revenue and cost variances plus toll stabilization adjustments during the 2015-2030 settlement term. The 2019 LTAA balance of $660 million consists of $488 million to be amortized in 2020 with the remaining balance to be amortized over 47 years.

7 This balance represents the amounts collected in tolls from shippers, and are included in the LMCI restricted investments, to fund future abandonment of the Company's CER-regulated pipeline facilities.

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

9 These balances represent the impact of U.S. Tax Reform. The regulatory liabilities will be amortized over varying terms that approximate the expected reversal of the underlying deferred tax liabilities that gave rise to the regulatory liabilities under the Reverse South Georgia Methodology. Refer to Note 17, Income taxes, for additional information on U.S. Tax Reform.

12. GOODWILL

The Company has recorded the following Goodwill on its acquisitions:

(millions of Canadian $)	U.S. Natural Gas Pipelines
Balance at January 1, 2018	13,084
Tuscarora impairment charge	(79)
Foreign exchange rate changes	1,173
Balance at December 31, 2018	14,178
Sale of Columbia midstream assets	**(595)**
Foreign exchange rate changes	**(696)**
Balance at December 31, 2019	**12,887**

As part of the annual goodwill impairment assessment, the Company evaluated qualitative factors impacting the fair value of the underlying reporting units. It was determined that it was more likely than not that the fair value of the reporting units exceeded their carrying amounts, including goodwill, and therefore, goodwill was not impaired.

Sale of Columbia Midstream Assets

On August 1, 2019, TC Energy completed the sale of certain Columbia midstream assets to a third party. As these assets constitute a business, and there is goodwill within this reporting unit, $595 million of Columbia's goodwill allocated to these assets was released and netted in the pre-tax gain on sale. The amount released was determined based on the relative fair values of the assets sold and the portion of the reporting unit retained. The fair value of the reporting unit was determined using a discounted cash flow analysis. Refer to Note 27, Acquisitions and dispositions, for additional details.

Tuscarora

In 2018, the Company finalized its regulatory filing for Tuscarora in response to the 2018 FERC Actions and Form 501-G requirements. Subsequently, Tuscarora reached a new rates settlement-in-principle with its customers and FERC approved these new rates on May 2, 2019. This, combined with changes to other valuation assumptions responsive to Tuscarora’s commercial environment, resulted in a determination that the fair value of Tuscarora did not exceed its carrying value, including goodwill. The fair value of the reporting unit was determined using a discounted cash flow analysis. The expected cash flows were discounted using a risk-adjusted discount rate to determine the fair value. As a result, the Company recorded a goodwill impairment charge of $79 million pre-tax within the U.S. Natural Gas Pipelines segment. This non-cash charge was recorded in Goodwill and other asset impairment charges in the Consolidated statement of income. As Tuscarora is a TC PipeLines, LP asset, the Company's share of this amount, after tax and net of non-controlling interests, was $15 million. The gross goodwill and accumulated impairment losses related to Tuscarora were US$82 million and US$59 million, respectively, at December 31, 2019 and December 31, 2018.

13. INTANGIBLE AND OTHER ASSETS

at December 31 (millions of Canadian $)	2019	2018
Capital projects in development	**1,715**	1,051
Employee post-retirement benefits (Note 24)	**162**	192
Deferred income tax assets (Note 17)	**37**	322
Fair value of derivative contracts (Note 25)	**7**	61
Other	**247**	295
	2,168	1,921

Capital projects in development

Keystone XL

In January 2018, the Company recommenced capitalizing development costs related to Keystone XL. At December 31, 2019, the amount included in Capital projects in development for this project was $1.5 billion (2018 – $0.8 billion). A portion of the carrying value is recoverable from shippers under certain conditions.

Reimbursement of Coastal GasLink pipeline costs

In accordance with provisions in the agreements with the LNG Canada joint venture participants, all five parties elected to reimburse TC Energy for their share of costs incurred prior to receiving the Final Investment Decision on the Coastal GasLink pipeline project. In November 2018, the Company received payments totaling $470 million which were recorded as a reduction of the carrying value of Coastal GasLink.

Prince Rupert Gas Transmission

In July 2017, the Company was notified that Pacific Northwest LNG would not be proceeding with its proposed LNG project and that Progress Energy (Progress) would be terminating its agreement with TC Energy for the development of the PRGT project. In accordance with the terms of the agreement, all project costs incurred to advance the project, including carrying charges, were fully recoverable upon termination and in October 2017 the Company received the $634 million reimbursement from Progress.

Energy East and Related Projects Impairment

In October 2017, the Company informed the NEB that it would 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. The non-cash charge was recorded in Goodwill and other asset impairment charges in the Consolidated statement of income.

14. NOTES PAYABLE

(millions of Canadian $, unless otherwise noted)	2019 Outstanding at December 31	2019 Weighted Average Interest Rate per Annum at December 31	2018 Outstanding at December 31	2018 Weighted Average Interest Rate per Annum at December 31
Canada[1]	**4,034**	**2.1%**	2,117	2.5%
U.S. (2019 – nil; 2018 – US$448)	**—**	**—**	611	3.1%
Mexico (2019 – US$205; 2018 – US$25)[2]	**266**	**2.7%**	34	3.3%
	4,300		2,762	

1 At December 31, 2019, Notes payable consisted of Canadian dollar denominated notes of $1,353 million (2018 - $961 million) and U.S. dollar denominated notes of US$2,068 million (2018 - US$847 million).

2 The demand senior unsecured revolving credit facility for the Company's Mexico subsidiary can be drawn in either Mexican pesos or U.S. dollars, up to the total facility amount of MXN 5.0 billion or the equivalent in U.S. dollars.

At December 31, 2019, Notes payable consists of short-term borrowings in Canada by TransCanada PipeLines Limited (TCPL) and in Mexico by a wholly-owned Mexican subsidiary.

At December 31, 2019, total committed revolving and demand credit facilities were $12.6 billion (2018 – $12.9 billion). When drawn, interest on these lines of credit is charged at negotiated floating rates of Canadian and U.S. banks, and at other negotiated financial bases. These unsecured credit facilities included the following:

at December 31 (billions of Canadian $, unless otherwise noted) Borrower	Description	Matures	2019 Total Facilities	2019 Unused Capacity	2018 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 2024	**3.0**	**3.0**	3.0
TCPL/TCPL USA/ Columbia/TAIL	Supports TCPL's and TCPL USA's U.S. dollar commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2020	**US 4.5**	**US 4.5**	US 4.5
TCPL/TCPL USA/ Columbia/TAIL	For general corporate purposes of the borrowers, guaranteed by TCPL	December 2022	**US 1.0**	**US 1.0**	US 1.0
Demand senior unsecured revolving credit facilities[1]:					
TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity; TCPL USA facility guaranteed by TCPL	Demand	**2.1**	**1.1**	2.1
Mexico subsidiary[2]	For Mexico general corporate purposes, guaranteed by TCPL	Demand	**MXN 5.0**	**MXN 1.1**	MXN 5.0

1 Provisions of various credit arrangements with the Company's subsidiaries can restrict their ability to declare and pay dividends or make distributions under certain circumstances. If such restrictions apply, they may, in turn, have an impact on the Company's ability to declare and pay dividends on common and preferred shares. These credit arrangements also require the Company to comply with various affirmative and negative covenants and maintain certain financial ratios. At December 31, 2019, the Company was in compliance with all debt covenants.

2 The demand senior unsecured revolving credit facility for the Company's Mexico subsidiary can be drawn in either Mexican pesos or U.S. dollars, up to the total facility amount of MXN 5.0 billion or the equivalent in U.S. dollars.

For the year ended December 31, 2019, the cost to maintain the above facilities was $11 million (2018 – $12 million; 2017 – $7 million).

At December 31, 2019, the Company's operated affiliates had an additional $0.8 billion (2018 – $0.8 billion) of undrawn capacity on third-party committed credit facilities.

15. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	2019	2018
Trade payables	**3,314**	3,224
Regulatory liabilities (Note 11)	**696**	591
Fair value of derivative contracts (Note 25)	**115**	922
Unredeemed shares of Columbia Pipeline Group, Inc.	**—**	357
Other	**419**	314
	4,544	5,408

On October 22, 2019, TC Energy made a payment to dissenting Columbia Pipeline Group, Inc. shareholders in the amount of $373 million (US$284 million), representing the appraised value of their shares pursuant to a court decision, which affirmed the original Columbia Pipeline Group, Inc. share purchase price of US$25.50 per share.

16. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	2019	2018
Employee post-retirement benefits (Note 24)	**540**	569
Operating lease obligations (Note 9)	**476**	—
Long-term contract liabilities (Note 5)	**226**	121
Fair value of derivative contracts (Note 25)	**81**	42
Asset retirement obligations	**62**	90
Guarantees	**32**	12
Other	**197**	174
	1,614	1,008

17. INCOME TAXES

U.S. Tax Reform

As part of U.S. Tax Reform, the enacted U.S. federal corporate income tax rate was reduced from 35 per cent to 21 per cent effective January 1, 2018 and resulted in a remeasurement of existing deferred income tax assets and deferred income tax liabilities related to the Company's U.S. businesses to reflect the new lower income tax rate as at December 31, 2017.

For the Company's U.S. businesses not subject to RRA, the reduction in enacted income tax rates resulted in a decrease in net deferred income tax liabilities and a deferred income tax recovery of $816 million in 2017. For the Company's U.S. businesses subject to RRA, the reduction in income tax rates resulted in a reduction in net deferred income tax liabilities and the recognition of a net regulatory liability of $1,686 million on the Consolidated balance sheet at December 31, 2017.

Net deferred income tax liabilities related to the cumulative remeasurements of employee post-retirement benefits included in AOCI were also adjusted with a corresponding increase in deferred income tax expense of $12 million in 2017.

Given the significance of the legislation, the U.S. Securities and Exchange Commission (SEC) staff issued guidance which allowed registrants to record provisional amounts at December 31, 2017 which could be adjusted as additional information became available, prepared or analyzed during a measurement period not to exceed one year.

At December 31, 2017, the Company considered amounts recorded related to U.S. Tax Reform to be reasonable estimates, however, certain amounts were provisional as the Company's interpretation, assessment and presentation of the impact of the tax law change were further clarified with additional guidance from regulatory, tax and accounting authorities received in 2018. With additional guidance provided during the permitted one-year measurement period, and upon finalizing its 2017 annual tax returns for its U.S. businesses, the Company recognized further adjustments to its deferred income tax liability and net regulatory liability balances as well as an additional deferred income tax recovery of $52 million in 2018.

In accordance with FERC Form 501-G and uncontested rate settlement filings, the ADIT balances for all pipelines held wholly or in part by TC PipeLines, LP were eliminated from their respective rate bases. As a result, net regulatory liabilities recorded for these assets pursuant to U.S. Tax Reform were written off, resulting in a further deferred income tax recovery of $115 million in 2018.

Under U.S. Tax Reform, the U.S. Treasury and the U.S. Internal Revenue Service issued proposed regulations in late 2018 which provided administrative guidance and clarified certain aspects of new laws with respect to interest deductibility, base erosion and anti-abuse tax (BEAT), the new dividend received deduction and anti-hybrid rules. In 2019, the U.S. Treasury and the U.S. Internal Revenue Service issued final BEAT regulations which did not have a material impact on the Company. The remaining proposed regulations are complex and comprehensive, and considerable uncertainty continues to exist pending release of the final regulations which is expected to occur in early 2020. If the proposed regulations are enacted as currently drafted, they are not expected to have a material impact on the Company's consolidated financial statements as at December 31, 2019.

Mexico Tax Reform

In late 2019, Mexico passed tax reform legislation related to, among other things, interest deductibility and tax reporting. These changes did not have an impact on the 2019 consolidated financial statements. The Company is currently assessing the impact for 2020 and future years.

Alberta Tax Rate Reduction

In June 2019, a reduction to the Alberta corporate tax rate was enacted. For the Company's Canadian businesses not subject to RRA, this resulted in a decrease in net deferred income tax liabilities and a deferred income tax recovery of $32 million. For the Company's Canadian businesses subject to RRA, this rate change resulted in the reduction of both net deferred income tax liabilities and long-term regulatory assets of $83 million on the Consolidated balance sheet at December 31, 2019.

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	2019	2018	2017
Current			
Canada	**84**	65	113
Foreign[1]	**615**	250	36
	699	315	149
Deferred			
Canada	**(29)**	49	(185)
Foreign	**84**	235	751
Foreign – U.S. Tax Reform and 2018 FERC Actions	**—**	(167)	(804)
	55	117	(238)
Income Tax Expense/(Recovery)	**754**	432	(89)

1 The December 31, 2019 current foreign Income tax expense mainly relates to the Columbian midstream sale that closed on August 1, 2019. Refer to Note 27, Acquisitions and dispositions, for additional information.

Geographic Components of Income before Income Taxes

year ended December 31 (millions of Canadian $)	2019	2018	2017
Canada	**1,144**	433	(339)
Foreign	**4,043**	3,516	3,645
Income before Income Taxes	**5,187**	3,949	3,306

Reconciliation of Income Tax Expense/(Recovery)

year ended December 31 (millions of Canadian $)	**2019**	**2018**	**2017**
Income before income taxes	**5,187**	3,949	3,306
Federal and provincial statutory tax rate	**26.5%**	27.0%	27.0%
Expected income tax expense	**1,375**	1,066	893
Valuation allowance release	**(259)**	—	—
Foreign income tax rate differentials	**(206)**	(432)	(81)
Income tax differential related to regulated operations	**(159)**	(54)	(42)
(Income)/loss from non-controlling interests	**(78)**	50	(64)
Alberta tax rate reduction	**(32)**	—	—
Non-taxable portion of capital gains	**(28)**	(11)	(42)
Non-deductible goodwill on the Columbia midstream disposition	**154**	—	—
U.S. Tax Reform and 2018 FERC Actions	**—**	(167)	(804)
Asset impairment charges	**—**	—	34
Non-deductible amounts	**—**	—	4
Other	**(13)**	(20)	13
Income Tax Expense/(Recovery)	**754**	432	(89)

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	**2019**	**2018**
Deferred Income Tax Assets		
Tax loss and credit carryforwards	**1,046**	1,238
Regulatory and other deferred amounts	**692**	858
Difference in accounting and tax bases of impaired assets and assets held for sale	**538**	574
Unrealized foreign exchange losses on long-term debt	**260**	491
Financial instruments	**23**	—
Other	**70**	292
	2,629	3,453
Less: Valuation allowance	**673**	1,159
	1,956	2,294
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment and PPAs	**6,197**	6,449
Equity investments	**1,087**	1,069
Taxes on future revenue requirement	**232**	300
Other	**106**	180
	7,622	7,998
Net Deferred Income Tax Liabilities	**5,666**	5,704

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

at December 31 (millions of Canadian $)	2019	2018
Deferred Income Tax Assets		
Intangible and other assets (Note 13)	**37**	322
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**5,703**	6,026
Net Deferred Income Tax Liabilities	**5,666**	5,704

At December 31, 2019, the Company has recognized the benefit of non-capital loss carryforwards of $1,929 million (2018 – $1,867 million) for federal and provincial purposes in Canada, which expire from 2030 to 2039. In addition, the Company has not yet recognized the benefit of capital loss carryforwards of $598 million (2018 – $821 million) for federal and provincial purposes in Canada. The Company also has Ontario minimum tax credits of $102 million (2018 – $91 million), which expire from 2026 to 2039.

At December 31, 2019, the Company has fully recognized the benefit of net operating loss carryforwards of US$1,098 million (2018 – US$889 million) for federal purposes in the U.S., which expire from 2029 to 2037.

At December 31, 2019, the Company has recognized the benefit of net operating loss carryforwards of US$4 million (2018 – US$3 million) in Mexico, which expire from 2024 to 2029.

The Company recorded a valuation allowance of $673 million and $1,159 million against the deferred income tax asset balances as at December 31, 2019 and December 31, 2018, respectively. The decrease in the valuation allowance is primarily a result of the foreign exchange movement on unrecognized capital losses, realized capital gains and the rationalization of legal entities. These changes resulted in a deferred income tax recovery of $259 million being recognized in 2019. As of each reporting date, the Company considers new evidence, both positive and negative, that could affect its view of the future realization of deferred tax assets. As at December 31, 2019, the Company determined there was sufficient positive evidence to conclude that it is more likely than not that the net deferred tax assets will be realized.

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Deferred income tax liabilities would have increased at December 31, 2019 by approximately $648 million (2018 – $619 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $713 million, net of refunds, were made in 2019 (2018 – payments, net of refunds, of $338 million; 2017 – payments, net of refunds, of $247 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 $)	2019	2018	2017
Unrecognized tax benefit at beginning of year	**19**	15	18
Gross increases – tax positions in prior years	**13**	13	—
Gross decreases – tax positions in prior years	**(1)**	(5)	(1)
Gross increases – tax positions in current year	**—**	—	2
Lapse of statutes of limitations	**(2)**	(4)	(4)
Unrecognized Tax Benefit at End of Year	**29**	19	15

Subject to the results of audit examinations by taxing authorities and other legislative amendments, TC Energy does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its financial statements.

TC Energy and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2011. Substantially all material U.S. federal, state and local income tax matters have been concluded for years through 2013. Substantially all material Mexico income tax matters have been concluded for years through 2013.

TC Energy's practice is to recognize interest and penalties related to income tax uncertainties in Income tax expense. Income tax expense for the year ended December 31, 2019 reflects $4 million of interest expense (2018 – $1 million of interest recovery; 2017 – nil of interest expense). At December 31, 2019, the Company accrued $7 million in interest expense (December 31, 2018 – $3 million). The Company incurred no penalties associated with income tax uncertainties related to Income tax expense for the years ended December 31, 2019, 2018 and 2017 and no penalties were accrued as at December 31, 2019 and 2018.

18. LONG-TERM DEBT

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2019 Outstanding at December 31	2019 Interest Rate[1]	2018 Outstanding at December 31	2018 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian	2020	**250**	**11.8%**	350	11.4%
U.S. (2019 and 2018 – US$400)	2021	**518**	**9.9%**	546	9.9%
Medium Term Notes					
Canadian	2021 to 2049	**9,491**	**4.6%**	7,504	4.8%
Senior Unsecured Notes					
U.S. (2019 – US$14,792; 2018 – US$17,192)	2020 to 2049	**19,174**	**5.2%**	23,456	5.1%
		29,433		31,856	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian	2024	**100**	**9.9%**	100	9.9%
U.S. (2019 and 2018 – US$200)	2023	**259**	**7.9%**	273	7.9%
Medium Term Notes					
Canadian	2025 to 2030	**504**	**7.4%**	504	7.4%
U.S. (2019 and 2018 – US$33)	2026	**42**	**7.5%**	44	7.5%
		905		921	
COLUMBIA PIPELINE GROUP, INC.					
Senior Unsecured Notes					
U.S. (2019 and 2018 – US$2,250)[2]	2020 to 2045	**2,916**	**4.4%**	3,070	4.4%
TC PIPELINES, LP					
Unsecured Loan Facility					
U.S. (2019 – nil; 2018 – US$40)		**—**	**—**	55	3.8%
Unsecured Term Loan					
U.S. (2019 – US$450; 2018 – US$500)	2022	**583**	**2.9%**	682	3.6%
Senior Unsecured Notes					
U.S. (2019 and 2018 – US$1,200)	2021 to 2027	**1,556**	**4.4%**	1,637	4.4%
		2,139		2,374	
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2019 and 2018 – US$672)	2021 to 2026	**872**	**7.2%**	918	7.2%

Outstanding amounts (millions of Canadian $, unless otherwise noted)	**Maturity Dates**	**2019** **Outstanding at December 31**	**2019** **Interest Rate**[1]	**2018** **Outstanding at December 31**	**2018** **Interest Rate**[1]
GAS TRANSMISSION NORTHWEST LLC					
Unsecured Term Loan					
U.S. (2019 – nil; 2018 – US$35)		**—**	**—**	48	3.3%
Senior Unsecured Notes					
U.S. (2019 and 2018 – US$250)	2020 to 2035	**324**	**5.6%**	341	5.6%
		324		389	
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. (2019 – US$219; 2018 – US$240)	2021 to 2030	**284**	**7.7%**	327	7.7%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Unsecured Loan Facility					
U.S. (2019 – US$39; 2018 – US$19)	2023	**51**	**3.0%**	26	3.6%
TUSCARORA GAS TRANSMISSION COMPANY					
Unsecured Term Loan					
U.S. (2019 – US$23; 2018 – US$24)	2020	**30**	**2.8%**	33	3.5%
NORTH BAJA PIPELINE, LLC					
Unsecured Term Loan					
U.S. (2019 and 2018 – US$50)	2021	**65**	**2.8%**	68	3.5%
		37,019		39,982	
Current portion of long-term debt		**(2,705)**		(3,462)	
Unamortized debt discount and issue costs		**(228)**		(241)	
Fair value adjustments[3]		**194**		230	
		34,280		36,509	

1 Interest rates are the effective interest rates except for those pertaining to long-term debt issued for the Company's Canadian regulated natural gas operations, in which case the weighted average interest rate is presented as approved by the regulators. The effective interest rate is calculated by discounting the expected future interest payments, adjusted for loan fees, premiums and discounts. Weighted average and effective interest rates are stated as at the respective outstanding dates.

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

3 The fair value adjustments include $193 million (2018 – $232 million) related to the acquisition of Columbia. These adjustments also include an increase of $1 million (2018 – decrease of $2 million) related to hedged interest rate risk. Refer to Note 25, Risk management and financial instruments, for additional information.

Principal Repayments

At December 31, 2019, principal repayments for the next five years on the Company's long-term debt are approximately as follows:

(millions of Canadian $)	**2020**	**2021**	**2022**	**2023**	**2024**
Principal repayments on long-term debt	2,705	1,966	1,932	1,897	289

Long-Term Debt Issued

The Company issued long-term debt over the three years ended December 31, 2019 as follows:

(millions of Canadian $, unless otherwise noted) Company	Issue Date	Type	Maturity Date	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED					
	September 2019	Medium Term Notes	September 2029	700	3.00%
	September 2019	Medium Term Notes	July 2048	300	4.18% [1]
	April 2019	Medium Term Notes	October 2049	1,000	4.34%
	October 2018	Senior Unsecured Notes	March 2049	US 1,000	5.10%
	October 2018	Senior Unsecured Notes	May 2028	US 400	4.25% [2]
	July 2018	Medium Term Notes	July 2048	800	4.18%
	July 2018	Medium Term Notes	March 2028	200	3.39% [3]
	May 2018	Senior Unsecured Notes	May 2028	US 1,000	4.25%
	May 2018	Senior Unsecured Notes	May 2048	US 1,000	4.875%
	May 2018	Senior Unsecured Notes	May 2038	US 500	4.75%
	November 2017	Senior Unsecured Notes	November 2019	US 550	Floating
	November 2017	Senior Unsecured Notes	November 2019	US 700	2.125%
	September 2017	Medium Term Notes	March 2028	300	3.39%
	September 2017	Medium Term Notes	September 2047	700	4.33%
NORTHERN COURIER PIPELINE LIMITED PARTNERSHIP[4,5]					
	July 2019	Senior Secured Notes	June 2042	1,000	3.365%
NORTH BAJA PIPELINE, LLC					
	December 2018	Unsecured Term Loan	December 2021	US 50	Floating
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
	April 2018	Unsecured Loan Facility	April 2023	US 19	Floating
TUSCARORA GAS TRANSMISSION COMPANY					
	August 2017	Unsecured Term Loan	August 2020	US 25	Floating
TC PIPELINES, LP					
	May 2017	Senior Unsecured Notes	May 2027	US 500	3.90%

1 Reflects coupon rate on re-opening of a pre-existing medium-term notes (MTN) issue. The MTNs were issued at a premium to par, resulting in a re-issuance yield of 3.991 per cent.

2 Reflects coupon rate on re-opening of a pre-existing senior unsecured notes issue. The notes were issued at a discount to par, resulting in a re-issuance yield of 4.439 per cent.

3 Reflects coupon rate on re-opening of a pre-existing MTN issue. The MTNs were issued at a discount to par, resulting in a re-issuance yield of 3.41 per cent.

4 Principal and interest payments are made semi-annually over the life of the senior secured notes.

5 Subsequent to the debt issuance, TC Energy completed the sale of an 85 per cent equity interest in Northern Courier. The Company's remaining 15 per cent interest is accounted for using the equity method. Refer to Note 27, Acquisitions and dispositions, for additional information.

Long-Term Debt Retired/Repaid

The Company retired/repaid long-term debt over the three years ended December 31, 2019 as follows:

(millions of Canadian $, unless otherwise noted) Company	Retirement/ Repayment Date	Type	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED				
	November 2019	Senior Unsecured Notes	US 700	2.125%
	November 2019	Senior Unsecured Notes	US 550	Floating
	May 2019	Medium Term Notes	13	9.35%
	March 2019	Debentures	100	10.50%
	January 2019	Senior Unsecured Notes	US 750	7.125%
	January 2019	Senior Unsecured Notes	US 400	3.125%
	August 2018	Senior Unsecured Notes	US 850	6.50%
	March 2018	Debentures	150	9.45%
	January 2018	Senior Unsecured Notes	US 500	1.875%
	January 2018	Senior Unsecured Notes	US 250	Floating
	December 2017	Debentures	100	9.80%
	November 2017	Senior Unsecured Notes	US 1,000	1.625%
	June 2017	Acquisition Bridge Facility[1]	US 1,513	Floating
	February 2017	Acquisition Bridge Facility[1]	US 500	Floating
	January 2017	Medium Term Notes	300	5.10%
TC PIPELINES, LP				
	June 2019	Unsecured Term Loan	US 50	Floating
	December 2018	Unsecured Term Loan	US 170	Floating
GAS TRANSMISSION NORTHWEST LLC				
	May 2019	Unsecured Term Loan	US 35	Floating
COLUMBIA PIPELINE GROUP, INC.				
	June 2018	Senior Unsecured Notes	US 500	2.45%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM				
	May 2018	Senior Secured Notes	US 18	5.90%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP				
	March 2018	Senior Unsecured Notes	US 9	6.73%
TUSCARORA GAS TRANSMISSION COMPANY				
	August 2017	Senior Secured Notes	US 12	3.82%
TRANSCANADA PIPELINE USA LTD.				
	June 2017	Acquisition Bridge Facility[1]	US 630	Floating
	April 2017	Acquisition Bridge Facility[1]	US 1,070	Floating

1 These facilities were put in place to finance a portion of the Columbia acquisition and were fully retired in 2017.

Interest Expense

year ended December 31 (millions of Canadian $)	2019	2018	2017
Interest on long-term debt	**1,931**	1,877	1,794
Interest on junior subordinated notes	**427**	391	348
Interest on short-term debt	**106**	73	33
Capitalized interest	**(186)**	(124)	(173)
Amortization and other financial charges[1]	**55**	48	67
	2,333	2,265	2,069

1 Amortization and other financial charges includes amortization of transaction costs and debt discounts calculated using the effective interest method and losses on derivatives used to manage the Company's exposure to changes in interest rates.

The Company made interest payments of $2,295 million in 2019 (2018 – $2,156 million; 2017 – $1,987 million) on long-term debt, junior subordinated notes and short-term debt, net of interest capitalized.

19. JUNIOR SUBORDINATED NOTES

Outstanding loan amount (millions of Canadian $, unless otherwise noted)	Maturity Date	2019 Outstanding at December 31	2019 Effective Interest Rate[1]	2018 Outstanding at December 31	2018 Effective Interest Rate[1]
TRANSCANADA PIPELINES LIMITED[2]					
US$1,000 notes issued 2007 at 6.35%[3]	2067	**1,296**	**5.1%**	1,364	5.6%
US$750 notes issued 2015 at 5.875%[4,5]	2075	**972**	**6.0%**	1,024	6.5%
US$1,200 notes issued 2016 at 6.125%[4,5]	2076	**1,556**	**6.7%**	1,637	7.2%
US$1,500 notes issued 2017 at 5.55%[4,5]	2077	**1,944**	**5.7%**	2,047	6.2%
$1,500 notes issued 2017 at 4.90%[4,5]	2077	**1,500**	**5.4%**	1,500	5.5%
US$1,100 notes issued 2019 at 5.75%[4,5]	2079	**1,426**	**6.3%**	—	—
		8,694		7,572	
Unamortized debt discount and issue costs		**(80)**		(64)	
		8,614		7,508	

1 The effective interest rate is calculated by discounting the expected future interest payments using the coupon rate and any estimated future rate resets, adjusted for issue costs and discounts.

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

3 In May 2017, Junior subordinated notes of US$1 billion converted from a fixed rate of 6.35 per cent to a floating rate that is reset quarterly to the three-month LIBOR plus 2.21 per cent.

4 The Junior subordinated notes were issued to TransCanada Trust, a financing trust subsidiary wholly-owned by TCPL. While the obligations of the Trust are fully and unconditionally guaranteed by TCPL on a subordinated basis, the Trust is not consolidated in TC Energy's financial statements since TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are junior subordinated notes of TCPL.

5 The coupon rate is initially a fixed interest rate for the first 10 years and converts to a floating rate thereafter.

In September 2019, TransCanada Trust (the Trust) issued US$1.1 billion of Trust Notes – Series 2019-A to third party investors with a fixed interest rate of 5.50 per cent for the first 10 years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for US$1.1 billion of junior subordinated notes of TCPL at an initial fixed rate of 5.75 per cent, including a 0.25 per cent administration charge. The rate will reset commencing September 2029 until September 2049 to the then three-month LIBOR plus 4.404 per cent per annum; from September 2049 until September 2079, the interest rate will reset to the then three-month LIBOR plus 5.154 per cent per annum. Refer to Note 25, Risk management and financial instruments, for additional information regarding the expected impact to the Company with the cessation of the LIBOR at the end of 2021. The junior subordinated notes are callable at TCPL's option at any time on or after September 15, 2029 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

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 March 2017, 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.

Pursuant to the terms of the notes issued between the Trust and TCPL (the Trust Notes) and related agreements, in certain circumstances (1) TCPL may issue deferral preferred shares to holders of the Trust Notes in lieu of interest; and (2) TC Energy and TCPL would be prohibited from declaring or paying dividends on or redeeming their outstanding preferred shares (or, if none are outstanding, their respective common shares) until all deferral preferred shares are redeemed by TCPL. The Trust Notes may also be automatically exchanged for preferred shares of TCPL upon certain kinds of bankruptcy and insolvency events. All of these preferred shares would rank equally with any other outstanding first preferred shares of TCPL.

20. NON-CONTROLLING INTERESTS

The Company's Non-controlling interests included on the Consolidated balance sheet are as follows:

at December 31 (millions of Canadian $)	**2019**	**2018**
Non-controlling interest in TC PipeLines, LP	**1,634**	1,655

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

year ended December 31 (millions of Canadian $)	**2019**	**2018**	**2017**
Non-controlling interest in TC PipeLines, LP	**293**	(185)	220
Non-controlling interest in Portland Natural Gas Transmission System[1]	**—**	—	9
Non-controlling interest in Columbia Pipeline Partners LP[2]	**—**	—	9
	293	(185)	238

1 Non-controlling interest in 2017 for the period January to May when TC Energy sold its remaining interest in Portland to TC PipeLines, LP.

2 Non-controlling interest up to the February 17, 2017 acquisition of all publicly held common units of Columbia Pipeline Partners LP.

TC PipeLines, LP

During 2019, the non-controlling interest in TC PipeLines, LP remained at 74.5 per cent. In 2018, the non-controlling interest in TC PipeLines, LP ranged between 74.3 per cent and 74.5 per cent, and in 2017, between 73.2 per cent and 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.

Portland Natural Gas Transmission System

In June 2017, TC Energy sold its remaining 11.81 per cent directly held interest in Portland Natural Gas Transmission System (Portland) to TC PipeLines, LP and, as a result, since that date, non-controlling interest in Portland has been nil. Refer to Note 27, Acquisitions and dispositions, for additional information.

Columbia Pipeline Partners LP

In February 2017, TC Energy acquired all outstanding publicly held common units of Columbia Pipeline Partners LP 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.

Common Units of TC PipeLines, LP Subject to Rescission

At December 31, 2016, $106 million (US$82 million) of TC PipeLines, LP common units were recorded as Common units subject to rescission or redemption and classified outside equity on the Consolidated balance sheet. The Company classified these 1.6 million common units outside of equity because the potential rescission right of units were not within the control of the Company. At December 31, 2017, all rescission rights previously classified outside of equity had lapsed and been reclassified to equity.

21. COMMON SHARES

	Number of Shares (thousands)	Amount (millions of Canadian $)
Outstanding at January 1, 2017	863,759	20,099
Dividend reinvestment and share purchase plan	12,824	790
At-the-market equity issuance program[1]	3,462	216
Exercise of options	1,331	62
Outstanding at December 31, 2017	881,376	21,167
At-the-market equity issuance program[1]	20,050	1,118
Dividend reinvestment and share purchase plan	15,937	855
Exercise of options	734	34
Outstanding at December 31, 2018	918,097	23,174
Dividend reinvestment and share purchase plan	**15,165**	**931**
Exercise of options	**5,138**	**282**
Outstanding at December 31, 2019	**938,400**	**24,387**

1 Net of issue costs and deferred income taxes.

Common Shares Issued and Outstanding

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

Dividend Reinvestment and Share Purchase Plan

Under the Company's Dividend Reinvestment and Share Purchase Plan (DRP), eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. From July 1, 2016 to October 31, 2019, common shares under the DRP were issued from treasury at a two per cent discount. Commencing with the dividends declared October 31, 2019, common shares purchased with reinvested cash dividends under the Company's DRP will be acquired on the open market at 100 per cent of the weighted average purchase price.

TC Energy Corporation At-the-Market Equity Issuance Program

In June 2017, the Company established an At-the-Market Equity Issuance Program (ATM program) that allowed, 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 TC Energy common shares in Canada or the United States. The ATM program was effective for a 25-month period and was utilized as appropriate to assist in managing the Company's capital structure. Under the original ATM program, the Company could issue up to $1.0 billion in common shares or the U.S. dollar equivalent. In June 2018, the Company replenished the capacity available under the program which allowed for the issuance of additional common shares from treasury for an aggregate issuance limit of up to $1.0 billion in common shares for a revised total of $2.0 billion or the U.S. dollar equivalent.

In 2017, 3.5 million common shares were issued under the ATM program at an average price of $63.03 per share for proceeds of $216 million, net of approximately $2 million of related commissions and fees.

In 2018, 20 million common shares were issued under the ATM program at an average price of $56.13 per share for proceeds of $1.1 billion, net of approximately $10 million of related commissions and fees.

In July 2019, the ATM program expired with no common shares issued under it in 2019.

Basic and Diluted Net Income per Common Share

Net income per common share is calculated by dividing Net income attributable to common shares by the weighted average number of common shares outstanding. The higher weighted average number of shares for the diluted earnings per share calculation is due to options exercisable under TC Energy's Stock Option Plan and shares issuable under the DRP.

Weighted Average Common Shares Outstanding (millions)	**2019**	**2018**	**2017**
Basic	**929**	902	872
Diluted	**931**	903	874

Stock Options

	Number of Options (thousands)	**Weighted Average Exercise Prices**	**Weighted Average Remaining Contractual Life** (years)
Options outstanding at January 1, 2019	12,404	$52.83	
Options granted	**2,004**	**$56.90**	
Options exercised	**(5,138)**	**$49.08**	
Options forfeited/expired	**(176)**	**$56.69**	
Options Outstanding at December 31, 2019	**9,094**	**$55.77**	**4.1**
Options Exercisable at December 31, 2019	**5,110**	**$54.28**	**3.0**

At December 31, 2019, an additional 7,962,761 common shares were reserved for future issuance from treasury under TC Energy's Stock Option Plan. The contractual life of options granted is seven years. Options may be exercised at a price determined at the time the option is awarded and vest 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	**2019**	**2018**	**2017**
Weighted average fair value	**$6.37**	$5.80	$7.22
Expected life (years)[1]	**5.7**	5.7	5.7
Interest rate	**1.9%**	2.1%	1.2%
Volatility[2]	**19%**	16%	18%
Dividend yield	**5.0%**	4.2%	3.6%

1 Expected life is based on historical exercise activity.

2 Volatility is derived based on the average of both the historical and implied volatility of the Company's common shares.

The amount expensed for stock options, with a corresponding increase in Additional paid-in capital, was $13 million in 2019 (2018 – $13 million; 2017 – $12 million). At December 31, 2019, unrecognized compensation costs related to non-vested stock options was $14 million. The cost is expected to be fully recognized over a weighted average period of 1.7 years.

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian $, unless otherwise noted)	2019	2018	2017
Total intrinsic value of options exercised	**75**	10	28
Total fair value of options that have vested	**143**	101	140
Total options vested	**2.1 million**	2.1 million	2.3 million

As at December 31, 2019, the aggregate intrinsic value of the total options exercisable was $76 million and the aggregate intrinsic value of options outstanding was $122 million.

Shareholder Rights Plan

TC Energy'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.

22. PREFERRED SHARES

at December 31, 2019	Number of Shares Outstanding (thousands)	Current Yield	Annual Dividend Per Share[1,2]	Redemption Price Per Share	Redemption and Conversion Option Date	Right to Convert Into	Carrying Value December 31 2019 (millions of Canadian $)[3]	2018	2017
Cumulative First Preferred Shares									
Series 1	14,577	3.479%	$0.86975	$25.00	December 31, 2024	Series 2	**360**	233	233
Series 2	7,423	Floating [4]	Floating	$25.00	December 31, 2024	Series 1	**179**	306	306
Series 3	8,533	2.152%	$0.538	$25.00	June 30, 2020	Series 4	**209**	209	209
Series 4	5,467	Floating [4]	Floating	$25.00	June 30, 2020	Series 3	**134**	134	134
Series 5	12,714	2.263%	$0.56575	$25.00	January 30, 2021	Series 6	**310**	310	310
Series 6	1,286	Floating [4]	Floating	$25.00	January 30, 2021	Series 5	**32**	32	32
Series 7	24,000	3.903% [5]	$0.975752	$25.00	April 30, 2024	Series 8	**589**	589	589
Series 9	18,000	3.762% [5]	$0.9405	$25.00	October 30, 2024	Series 10	**442**	442	442
Series 11	10,000	3.80%	$0.95	$25.00	November 30, 2020	Series 12	**244**	244	244
Series 13	20,000	5.50%	$1.375	$25.00	May 31, 2021	Series 14	**493**	493	493
Series 15	40,000	4.90%	$1.225	$25.00	May 31, 2022	Series 16	**988**	988	988
							3,980	3,980	3,980

1 Each of the even-numbered series of preferred shares, if in existence, will be entitled to receive floating rate cumulative quarterly preferential dividends per share at an annualized rate equal to the 90-day Government of Canada Treasury bill rate (T-bill rate) plus 1.92 per cent (Series 2), 1.28 per cent (Series 4), 1.54 per cent (Series 6), 2.38 per cent (Series 8), 2.35 per cent (Series 10), 2.96 per cent (Series 12), 4.69 per cent (Series 14) and 3.85 per cent (Series 16). These rates reset quarterly with the then current T-Bill rate.

2 The odd-numbered series of preferred shares, if in existence, will be entitled to receive fixed rate cumulative quarterly preferential dividends, which will reset on the redemption and conversion option date and every fifth year thereafter, at an annualized rate equal to the then five-year Government of Canada bond yield plus 1.92 per cent (Series 1), 1.28 per cent (Series 3), 1.54 per cent (Series 5), 2.38 per cent (Series 7), 2.35 per cent (Series 9), 2.96 per cent (Series 11), 4.69 per cent, subject to a minimum of 5.50 per cent (Series 13) and 3.85 per cent, subject to a minimum of 4.90 per cent (Series 15).

3 Net of underwriting commissions and deferred income taxes.

4 The floating quarterly dividend rate for the Series 2 preferred shares is 3.572 per cent for the period starting December 31, 2019 to, but excluding, March 30, 2020. The floating quarterly dividend rate for the Series 4 preferred shares is 2.932 per cent for the period starting December 31, 2019 to, but excluding, March 30, 2020. The floating quarterly dividend rate for the Series 6 preferred shares is 3.164 per cent for the period starting October 30, 2019 to, but excluding, January 30, 2020. These rates will reset each quarter going forward.

5 No Series 7 or 9 preferred shares were converted on the April 30, 2019 or October 30, 2019 conversion option dates, respectively. As a result, the fixed rate dividend decreased for Series 7 from 4.00 per cent to 3.903 per cent on April 30, 2019 and for Series 9 from 4.250 per cent to 3.762 per cent on October 30, 2019, and are due to reset on every fifth anniversary thereafter.

The holders of preferred shares are entitled to receive a fixed cumulative quarterly preferential dividend as and when declared by the Board with the exception of Series 2, Series 4 and Series 6 preferred shares. The holders of Series 2, Series 4 and Series 6 preferred shares are entitled to receive quarterly floating rate cumulative preferential dividends as and when declared by the Board. The holders will have the right, subject to certain conditions, to convert their first preferred shares of a specified series into first preferred shares of another specified series on the conversion option date and every fifth anniversary thereafter as indicated in the table above.

TC Energy may, at its option, redeem all or a portion of the outstanding preferred shares for the redemption price per share, plus all accrued and unpaid dividends on the applicable redemption option date and on every fifth anniversary thereafter. In addition, Series 2, Series 4 and Series 6 preferred shares are redeemable by TC Energy at any time other than on a designated date for $25.50 per share plus all accrued and unpaid dividends on such redemption date.

On December 31, 2019, 173,954 Series 1 preferred shares were converted, on a one-for-one basis, into Series 2 preferred shares and 5,252,715 Series 2 preferred shares were converted, on a one-for-one basis, into Series 1 preferred shares.

23. OTHER COMPREHENSIVE (LOSS)/INCOME AND ACCUMULATED OTHER COMPREHENSIVE LOSS

Components of OCI, including the portion attributable to non-controlling interests and related tax effects, are as follows:

year ended December 31, 2019 (millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ (Expense)**	**Net of Tax Amount**
Foreign currency translation losses on net investment in foreign operations	**(914)**	**(30)**	**(944)**
Reclassification of foreign currency translation gains on disposal of foreign operations	**(13)**	**—**	**(13)**
Change in fair value of net investment hedges	**46**	**(11)**	**35**
Change in fair value of cash flow hedges	**(78)**	**16**	**(62)**
Reclassification to net income of gains and losses on cash flow hedges	**19**	**(5)**	**14**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**(15)**	**5**	**(10)**
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**14**	**(4)**	**10**
Other comprehensive loss on equity investments	**(114)**	**32**	**(82)**
Other Comprehensive Loss	**(1,055)**	**3**	**(1,052)**

year ended December 31, 2018 (millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ (Expense)**	**Net of Tax Amount**
Foreign currency translation gains on net investment in foreign operations	1,323	35	1,358
Change in fair value of net investment hedges	(57)	15	(42)
Change in fair value of cash flow hedges	(14)	4	(10)
Reclassification to net income of gains and losses on cash flow hedges	27	(6)	21
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	(153)	39	(114)
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	20	(5)	15
Other comprehensive income on equity investments	113	(27)	86
Other Comprehensive Income	1,259	55	1,314

year ended December 31, 2017 (millions of Canadian $)	Before Tax Amount	Income Tax Recovery/ (Expense)	Net of Tax Amount
Foreign currency translation losses on net investment in foreign operations	(746)	(3)	(749)
Reclassification of foreign currency translation gains on disposal of foreign operations	(77)	—	(77)
Change in fair value of cash flow hedges	3	—	3
Reclassification to net income of gains and losses on cash flow hedges	(3)	1	(2)
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	(14)	3	(11)
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	21	(5)	16
Other comprehensive loss on equity investments	(141)	35	(106)
Other Comprehensive Loss	(957)	31	(926)

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, 2017	(376)	(28)	(208)	(348)	(960)
Other comprehensive loss before reclassifications[2,3]	(590)	(1)	(11)	(117)	(719)
Amounts reclassified from AOCI	(77)	(2)	16	11	(52)
Net current period other comprehensive (loss)/income	(667)	(3)	5	(106)	(771)
AOCI balance at December 31, 2017	(1,043)	(31)	(203)	(454)	(1,731)
Other comprehensive income/(loss) before reclassifications[2]	1,150	(9)	(114)	72	1,099
Amounts reclassified from AOCI	—	16	15	12	43
Net current period other comprehensive income/(loss)	1,150	7	(99)	84	1,142
Reclassification of AOCI to retained earnings resulting from U.S. Tax Reform	—	1	(12)	(6)	(17)
AOCI balance at December 31, 2018	107	(23)	(314)	(376)	(606)
Other comprehensive loss before reclassifications[2]	**(824)**	**(49)**	**(10)**	**(86)**	**(969)**
Amounts reclassified from AOCI[4,5]	**(13)**	**14**	**10**	**5**	**16**
Net current period other comprehensive (loss)	**(837)**	**(35)**	**—**	**(81)**	**(953)**
AOCI balance at December 31, 2019	**(730)**	**(58)**	**(314)**	**(457)**	**(1,559)**

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

2 In 2019, other comprehensive loss before reclassifications on currency translation adjustments, cash flow hedges and equity investments are net of non-controlling interest losses of $85 million (2018 – $166 million gains; 2017 – $159 million losses), $13 million (2018 – $1 million losses; 2017 – $4 million gains) and $1 million (2018 and 2017 – nil), respectively.

3 Other comprehensive loss 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 $18 million ($13 million, net of tax) at December 31, 2019. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

5 In 2019, non-controlling interest gains related to amounts reclassified from AOCI on cash flow hedges and equity investments was nil.

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

year ended December 31	Amounts Reclassified From AOCI[1]			Affected Line Item in the Consolidated Statement of Income
(millions of Canadian $)	**2019**	**2018**	**2017**	
Cash flow hedges				
Commodities	**(7)**	(4)	20	Revenues (Power and Storage)
Interest	**(12)**	(18)	(17)	Interest expense
	(19)	(22)	3	Total before tax
	5	6	(1)	Income tax expense
	(14)	(16)	2	Net of tax[1,3]
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial gains and losses	**(14)**	(16)	(15)	Plant operating costs and other[2]
Settlement charge	**—**	(4)	(2)	Plant operating costs and other[2]
	(14)	(20)	(17)	Total before tax
	4	5	5	Income tax expense
	(10)	(15)	(12)	Net of tax[1]
Equity investments				
Equity income	**(8)**	(16)	(15)	Income from equity investments
	3	4	4	Income tax expense
	(5)	(12)	(11)	Net of tax[1,3]
Currency translation adjustments				
Realization of foreign currency translation gains on disposal of foreign operations	**13**	—	77	(Loss)/gain on assets held for sale/sold
	—	—	—	Income tax expense
	13	—	77	Net of tax[1]

1 Amounts in parentheses indicate expenses to the Consolidated statement of income.

2 These AOCI components are included in the computation of net benefit cost. Refer to Note 24, Employee post-retirement benefits, for additional information.

3 Amounts reclassified from AOCI on cash flow hedges and equity investments are net of non-controlling interest gains of nil (2018 – $5 million; 2017 – nil) and nil (2018 – $2 million; 2017 – nil), respectively.

24. 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. Effective January 1, 2019, there were certain amendments made to the Canadian DB Plan for new members whereby, subsequent to that date, benefits provided for these new members are based on years of service and highest average earnings over five consecutive years of employment. Upon commencement of retirement, pension benefits in the Canadian DB Plan increase annually by a portion of the increase in the Consumer Price Index. Net actuarial gains or losses are amortized out of AOCI over the EARSL of employees, which is approximately nine years at December 31, 2019 (2018 and 2017 – nine years).

On December 31, 2017, the Columbia DB Plan merged with TC Energy's U.S. DB Plan. Members accruing benefits in the Columbia DB Plan as of December 31, 2017 were provided an option to either continue receiving benefits in the Columbia DB Plan or instead participate in the existing U.S. DC Plan. In addition, on January 1, 2018, the Columbia other post-retirement benefit plan merged with TC Energy's U.S. other post-retirement benefit plan.

The Company also provides its employees with a savings plan in Canada, DC Plans consisting of 401(k) Plans in the U.S. and post-employment benefits other than pensions, including termination benefits and life insurance and medical benefits beyond those provided by government-sponsored plans. Net actuarial gains or losses for the plans are amortized out of AOCI over the EARSL of employees, which was approximately 11 years at December 31, 2019 (2018 and 2017 – 12 years). In 2019, the Company expensed $61 million (2018 – $59 million; 2017 – $42 million) for the savings and DC Plans.

In April 2017, the Company U.S. DB Plan was closed to non-union new entrants. All non-union hires now participate in the DC Plan.

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

year ended December 31 (millions of Canadian $)	**2019**	**2018**	**2017**
DB Plans	**122**	103	163
Other post-retirement benefit plans	**22**	23	7
Savings and DC Plans	**61**	59	42
	205	185	212

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 $12 million letter of credit to the Canadian DB Plan in 2019 (2018 – $17 million; 2017 – $27 million), resulting in a total of $289 million provided to the Canadian DB Plan under letters of credit at December 31, 2019.

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2019 and the next required valuation will be as at January 1, 2020.

In December 2018, the Company recorded a settlement resulting from lump sum payments made in 2018 to certain terminated non-union vested participants in the Company's U.S. DB Plan related to voluntary cash settlement options available to these participants. The impact of the settlement was determined using assumptions consistent with those employed at December 31, 2017. The settlement reduced the Company's U.S. DB Plan's unrealized actuarial losses by $4 million, which was included in OCI, and resulted in a settlement charge of $4 million which was recorded in net benefit costs in 2018. Effective December 1, 2018, the plan was amended to include this unlimited lump sum payment option for certain union employees who were not previously eligible.

In 2017, as a result of settlements and curtailments that occurred upon the completion of the U.S. Northeast power generation asset sales, interim remeasurements were performed on TC Energy's U.S. DB Plan and other post-retirement benefit plans. The impact of these remeasurements reduced the U.S. DB Plan's unrealized actuarial losses by $3 million, which was included in OCI, and resulted in a settlement charge of $2 million which was recorded in net benefit cost in 2017. These remeasurements had no impact on the other post-retirement benefit plan's unrealized actuarial losses.

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 $)	**2019**	**2018**	**2019**	**2018**
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**3,653**	3,646	**430**	375
Service cost	**126**	121	**5**	4
Interest cost	**142**	134	**17**	14
Employee contributions	**5**	5	**—**	—
Benefits paid	**(213)**	(177)	**(24)**	(23)
Actuarial loss/(gain)	**394**	(92)	**13**	43
Settlement	**—**	(71)	**—**	—
Foreign exchange rate changes	**(49)**	87	**(14)**	17
Benefit obligation – end of year	**4,058**	3,653	**427**	430
Change in Plan Assets				
Plan assets at fair value – beginning of year	**3,321**	3,451	**376**	365
Actual return on plan assets	**505**	(73)	**52**	(15)
Employer contributions[2]	**122**	103	**22**	23
Employee contributions	**5**	5	**—**	—
Benefits paid	**(212)**	(176)	**(24)**	(27)
Settlement	**—**	(71)	**—**	—
Foreign exchange rate changes	**(48)**	82	**(20)**	30
Plan assets at fair value – end of year	**3,693**	3,321	**406**	376
Funded Status – Plan Deficit	**(365)**	(332)	**(21)**	(54)

1 The benefit obligation for the Company's pension benefit plans represents the projected benefit obligation. The benefit obligation for the Company's other post-retirement benefit plans represents the accumulated post-retirement benefit obligation.
2 Excludes a $12 million letter of credit provided to the Canadian DB Plan for funding purposes (2018 – $17 million).

The amounts recognized on 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 $)	**2019**	**2018**	**2019**	**2018**
Intangible and other assets (Note 13)	**—**	—	**162**	192
Accounts payable and other	**—**	(1)	**(8)**	(8)
Other long-term liabilities (Note 16)	**(365)**	(331)	**(175)**	(238)
	(365)	(332)	**(21)**	(54)

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 $)	**2019**	2018	**2019**	2018
Projected benefit obligation[1]	**(4,058)**	(3,653)	**(182)**	(246)
Plan assets at fair value	**3,693**	3,321	**—**	—
Funded Status – Plan Deficit	**(365)**	(332)	**(182)**	(246)

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

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

at December 31 (millions of Canadian $)	**2019**	2018
Accumulated benefit obligation	**(3,719)**	(3,347)
Plan assets at fair value	**3,693**	3,321
Funded Status – Plan Deficit	**(26)**	(26)

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 $)	**2019**	2018
Accumulated benefit obligation	**(2,397)**	(3,347)
Plan assets at fair value	**2,351**	3,321
Funded Status – Plan Deficit	**(46)**	(26)

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	**2019**	2018	**2019**
Debt securities	**32%**	33%	**25% to 45%**
Equity securities	**58%**	56%	**40% to 70%**
Alternatives	**10%**	11%	**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 $)	**2019**	2018	**2019**	2018
Debt securities	**9**	8	**0.2%**	0.3%
Equity securities	**15**	7	**0.4%**	0.2%

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

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

The following table presents plan assets for DB Plans and other post-retirement benefits measured at fair value, which have been categorized into the three categories based on a fair value hierarchy. For additional information on the fair value hierarchy, refer to Note 25, 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 $)	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Asset Category										
Cash and Cash Equivalents	**58**	48	**—**	—	**—**	—	**58**	48	**1**	1
Equity Securities:										
Canadian	**402**	355	**189**	138	**—**	—	**591**	493	**14**	13
U.S.	**523**	460	**156**	116	**—**	—	**679**	576	**17**	16
International	**46**	40	**320**	281	**—**	—	**366**	321	**9**	9
Global	**136**	116	**297**	268	**—**	—	**433**	384	**11**	10
Emerging	**8**	8	**126**	138	**—**	—	**134**	146	**3**	4
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**198**	186	**—**	—	**198**	186	**5**	5
Provincial	**—**	—	**246**	198	**—**	—	**246**	198	**6**	5
Municipal	**—**	—	**12**	8	**—**	—	**12**	8	**—**	1
Corporate	**—**	—	**125**	112	**—**	—	**125**	112	**3**	3
U.S. Bonds:										
Federal	**421**	350	**7**	—	**—**	—	**428**	350	**11**	9
State	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Municipal	**—**	—	**1**	—	**—**	—	**1**	—	**—**	—
Corporate	**67**	145	**120**	51	**—**	—	**187**	196	**5**	5
International:										
Government	**7**	6	**4**	4	**—**	—	**11**	10	**—**	1
Corporate	**—**	19	**52**	18	**—**	—	**52**	37	**1**	1
Mortgage backed	**46**	128	**7**	—	**—**	—	**53**	128	**1**	3
Other Investments:										
Real estate	**—**	—	**—**	—	**196**	196	**196**	196	**5**	5
Infrastructure	**—**	—	**—**	—	**181**	163	**181**	163	**4**	4
Private equity funds	**—**	—	**—**	—	**2**	3	**2**	3	**—**	1
Funds held on deposit	**146**	142	**—**	—	**—**	—	**146**	142	**4**	4
	1,860	1,817	**1,860**	1,518	**379**	362	**4,099**	3,697	**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, 2017	216
Purchases and sales	127
Realized and unrealized gains	19
Balance at December 31, 2018	362
Purchases and sales	**35**
Realized and unrealized losses	**(18)**
Balance at December 31, 2019	**379**

The Company's expected funding contributions in 2020 are approximately $116 million for the DB Plans, approximately $7 million for the other post-retirement benefit plans and approximately $62 million for the savings plan and DC Plans. The Company expects to provide an additional estimated $12 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
2020	195	25
2021	199	25
2022	203	24
2023	207	24
2024	209	24
2025 to 2029	1,084	117

The rate used to discount pension and other post-retirement benefit plan obligations was developed based on a yield curve of primarily corporate AA bond yields at December 31, 2019. 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	**2019**	**2018**	**2019**	**2018**
Discount rate	**3.20%**	3.90%	**3.35%**	4.10%
Rate of compensation increase	**3.00%**	3.00%	**—**	—

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan costs were as follows:

	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
year ended December 31	**2019**	**2018**	**2017**	**2019**	**2018**	**2017**
Discount rate	**3.90%**	3.60%	3.95%	**4.10%**	3.70%	4.15%
Expected long-term rate of return on plan assets	**6.60%**	6.70%	6.50%	**4.30%**	4.00%	6.05%
Rate of compensation increase	**3.00%**	3.00%	1.20%	**—**	—	—

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 6.30 per cent weighted-average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2020 measurement purposes. The rate was assumed to decrease gradually to 4.50% by 2029 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	2	(2)
Effect on post-retirement benefit obligation	31	(25)

The net benefit cost recognized for the Company's pension benefit plans and other post-retirement benefit plans is as follows:

at December 31	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
(millions of Canadian $)	**2019**	2018	2017	**2019**	2018	2017
Service cost[1]	**126**	121	108	**5**	4	4
Other components of net benefit cost[1]						
Interest cost	**142**	134	122	**17**	14	14
Expected return on plan assets	**(222)**	(221)	(178)	**(15)**	(16)	(21)
Amortization of actuarial loss	**12**	15	14	**2**	1	1
Amortization of regulatory asset	**14**	18	37	**2**	—	1
Settlement charge – regulatory asset	**—**	—	2	**—**	—	—
Settlement charge – AOCI	**—**	4	2	**—**	—	—
	(54)	(50)	(1)	**6**	(1)	(5)
Net Benefit Cost Recognized	**72**	71	107	**11**	3	(1)

1 Service cost and other components of net benefit cost are included in Plant operating costs and other in the Consolidated statement of income.

Pre-tax amounts recognized in AOCI were as follows:

at December 31 (millions of Canadian $)	2019 Pension Benefits	2019 Other Post-Retirement Benefits	2018 Pension Benefits	2018 Other Post-Retirement Benefits	2017 Pension Benefits	2017 Other Post-Retirement Benefits
Net loss	**398**	**20**	364	53	273	11

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 2020 is $21 million and $2 million, respectively.

Pre-tax amounts recognized in OCI were as follows:

at December 31 (millions of Canadian $)	2019 Pension Benefits	2019 Other Post-Retirement Benefits	2018 Pension Benefits	2018 Other Post-Retirement Benefits	2017 Pension Benefits	2017 Other Post-Retirement Benefits
Amortization of net loss from AOCI to net income	**(12)**	**(2)**	(15)	(1)	(18)	(1)
Curtailment	**—**	**—**	—	—	(14)	(2)
Settlement	**—**	**—**	(4)	—	(11)	—
Funded status adjustment	**52**	**(37)**	110	43	46	(7)
	40	**(39)**	91	42	3	(10)

25. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TC Energy has exposure to market risk and counterparty credit risk, and has strategies, policies and limits in place to manage the impact of these risks on earnings, cash flow and shareholder value.

Risk management strategies, policies and limits are designed to ensure TC Energy's risks and related exposures are in line with the Company's business objectives and risk tolerance. Market risk and counterparty credit risk are managed within limits established by the Company's Board of Directors, implemented by senior management and monitored by the Company's risk management and internal audit groups. The Board of Directors' Audit Committee oversees how management monitors compliance with market risk and counterparty credit risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework.

Market Risk

The Company constructs and invests in energy infrastructure projects, purchases and sells commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. Certain of these activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which may affect the Company's earnings and the value of the financial instruments it holds. The Company assesses contracts used to manage market risk to determine whether all, or a portion, meets the definition of a derivative.

Derivative contracts the Company uses to assist in managing the exposure to market risk may consist of the following:
- Forwards and futures contracts – agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future
- Swaps – agreements between two parties to exchange streams of payments over time according to specified terms
- Options – agreements that convey the right, but not the obligation of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period.

Commodity price risk

The following strategies may be used to manage exposure to commodity price risk in the Company's non-regulated businesses:
- In the Company's power generation business, TC Energy manages the exposure to fluctuating commodity prices through long-term contracts and hedging activities including selling and purchasing power and natural gas in forward markets
- In the Company's non-regulated natural gas storage business, TC Energy's exposure to seasonal natural gas price spreads is managed with a portfolio of third-party storage capacity contracts and through offsetting purchases and sales of natural gas in forward markets to lock in future positive margins
- In the Company's liquids marketing business, TC Energy enters into pipeline and storage terminal capacity contracts, as well as crude purchase and sale agreements. TC Energy 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.

In May 2019, TC Energy sold its remaining U.S. Power marketing contracts completing the divestiture of its U.S. Northeast power business which began in 2017, greatly reducing its exposure to electricity price risk.

Interest rate risk

TC Energy utilizes short-term and long-term debt to finance its operations which exposes the Company to interest rate risk. TC Energy typically pays fixed rates of interest on its long-term debt and floating rates on its commercial paper programs and amounts drawn on its credit facilities. A small portion of TC Energy's long-term debt is at floating interest rates. In addition, the Company is exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. The Company manages its interest rate risk using interest rate swaps.

Many of TC Energy's financial instruments and contractual obligations with variable rate components reference the London Interbank Offered Rate (LIBOR). This rate will cease to be published at the end of 2021 and will likely be replaced by a secured overnight financing rate. The Company will continue to monitor developments and the impact, if any, on the business.

Foreign exchange risk

TC Energy generates revenues and incurs expenses and capital expenditures that are denominated in currencies other than Canadian dollars. As a result, the Company's earnings and cash flows are exposed to currency fluctuations.

A portion of TC Energy's businesses generate earnings in U.S. dollars, but since its financial results are reported in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect its net income. As the Company's U.S. dollar-denominated operations continue to grow, this exposure increases. A portion of this risk is offset by interest expense on U.S. dollar-denominated debt. The balance of the exposure is actively managed on a rolling one-year basis using foreign exchange derivatives, however, the natural exposure beyond that period remains.

Net investment hedges

The Company hedges a portion of its net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency swaps and foreign exchange options.

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

at December 31 (millions of Canadian $, unless otherwise noted)	2019 Fair Value[1,2]	2019 Notional Amount	2018 Fair Value[1,2]	2018 Notional Amount
U.S. dollar cross-currency interest rate swaps (maturing 2023)[3]	**3**	**US 100**	(43)	US 300
U.S. dollar foreign exchange options (maturing 2020 to 2021)	**10**	**US 3,000**	(47)	US 2,500
	13	**US 3,100**	(90)	US 2,800

1 Fair value equals carrying value.

2 No amounts have been excluded from the assessment of hedge effectiveness.

3 In 2019, Net income includes net realized gains of nil (2018 – gains of $2 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)	2019	2018
Notional amount	**29,300 (US 22,600)**	31,000 (US 22,700)
Fair value	**33,400 (US 25,700)**	31,700 (US 23,200)

Counterparty Credit Risk

TC Energy's exposure to counterparty credit risk consists of its cash and cash equivalents, accounts receivable, available-for-sale assets, the fair value of derivative assets and a loan receivable.

During the year, continued low natural gas prices presented increased financial challenges for some of our natural gas shippers that resulted in restructuring and bankruptcy for certain shipper entities with no significant negative impact to the Company's 2019 earnings or cash flow. The Company monitors its counterparties and reviews its accounts receivable regularly and, if needed, the Company records allowances for doubtful accounts using the specific identification method. At December 31, 2019 and 2018, there were no significant amounts past due or impaired, no significant credit risk concentration and no significant credit losses during the year.

At times, the Company's counterparties may endure financial challenges resulting from commodity price and market volatility, economic instability and political or regulatory changes. In addition to actively monitoring these situations, there are a number of factors that mitigate TC Energy's counterparty credit risk exposure in the event of default, including:

- contractual rights and remedies together with the utilization of contractually-based financial assurances
- current regulatory frameworks governing certain TC Energy operations
- competitive position of the Company's assets and the demand for the Company's services, and
- potential recovery of unpaid amounts through bankruptcy and similar proceedings.

TC Energy has significant credit and performance exposures to financial institutions because they hold cash deposits and provide committed credit lines and letters of credit that help manage the Company's exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

Fair Value of Non-Derivative Financial Instruments

Available-for-sale assets are recorded at fair value which is calculated using quoted market prices where available. Certain non-derivative financial instruments included in cash and cash equivalents, accounts receivable, 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. Each of these instruments are 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 $)	2019		2018	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt, including current portion[1,2] (Note 18)	**(36,985)**	**(43,187)**	(39,971)	(42,284)
Junior subordinated notes (Note 19)	**(8,614)**	**(8,777)**	(7,508)	(6,665)
	(45,599)	**(51,964)**	(47,479)	(48,949)

1 Long-term debt is recorded at amortized cost, except for US$200 million (2018 – US$750 million) that is attributed to hedged risk and recorded at fair value.

2 Net income in 2019 included unrealized losses of $3 million (2018 – $2 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$200 million of long-term debt at December 31, 2019 (2018 – US$750 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:

at December 31 (millions of Canadian $)	2019		2018	
	LMCI Restricted Investments	**Other Restricted Investments[1]**	**LMCI Restricted Investments**	**Other Restricted Investments[1]**
Fair value of fixed income securities[2]				
Maturing within 1 year	**—**	**6**	—	22
Maturing within 1-5 years	**26**	**100**	—	110
Maturing within 5-10 years	**801**	**—**	140	—
Maturing after 10 years	**61**	**—**	952	—
Fair value of equity securities[2]	**556**	**—**	—	—
	1,444	**106**	1,092	132

1 Other restricted investments have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

2 Available-for-sale assets are recorded at fair value and included in Other current assets and Restricted investments on the Company's Consolidated balance sheet.

year ended December 31 (millions of Canadian $)	2019		2018		2017	
	LMCI restricted investments[1]	Other restricted investments[2]	LMCI restricted investments[1]	Other restricted investments[2]	LMCI restricted investments[1]	Other restricted investments[2]
Net unrealized gains/(losses)	**32**	**3**	11	—	(3)	1
Net realized gains/(losses)[3]	**60**	**—**	(4)	—	(1)	—

1 Gains and losses arising from changes in the fair value of LMCI restricted investments impact the subsequent amounts to be collected through tolls to cover future pipeline abandonment costs. As a result, the Company records these gains and losses as regulatory assets or liabilities.

2 Gains and losses on other restricted investments are included in Interest income and other in the Company's Consolidated statement of income.

3 Realized gains and losses on the sale of LMCI restricted investments are determined using the average cost basis.

Fair Value of Derivative Instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses year-end market rates and applies a discounted cash flow valuation model. The fair value of commodity derivatives has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used. The fair value of options has been calculated using the Black-Scholes pricing model. Credit risk has been taken into consideration when calculating the fair value of derivative instruments. Unrealized gains and losses on derivative instruments are not necessarily representative of the amounts that will be realized on settlement.

In some cases, even though the derivatives are considered to be effective economic hedges, they do not meet the specific criteria for hedge accounting treatment or are not designated as a hedge and are accounted for at fair value with changes in fair value recorded in net income in the period of change. This may expose the Company to increased variability in reported earnings because the fair value of the derivative instruments can fluctuate significantly from period to period.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipeline exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, are expected to be recovered or refunded through the tolls charged by the Company. As a result, these gains and losses are deferred as regulatory assets or regulatory liabilities and are refunded to or collected from the ratepayers in subsequent years when the derivative settles.

Balance Sheet Presentation of Derivative Instruments

The balance sheet classification of the fair value of derivative instruments as at December 31, 2019 is as follows:

at December 31, 2019 (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]	—	—	—	**118**	**118**
Foreign exchange	—	—	**10**	**61**	**71**
Interest rate	—	**1**	—	—	**1**
	—	**1**	**10**	**179**	**190**
Intangible and other assets (Note 13)					
Foreign exchange	—	—	**5**	—	**5**
Interest rate	**2**	—	—	—	**2**
	2	—	**5**	—	**7**
Total Derivative Assets	**2**	**1**	**15**	**179**	**197**
Accounts payable and other (Note 15)					
Commodities[2]	**(4)**	—	—	**(104)**	**(108)**
Foreign exchange	—	—	**(1)**	**(3)**	**(4)**
Interest rate	**(3)**	—	—	—	**(3)**
	(7)	—	**(1)**	**(107)**	**(115)**
Other long-term liabilities (Note 16)					
Commodities[2]	**(6)**	—	—	**(11)**	**(17)**
Foreign exchange	—	—	**(1)**	—	**(1)**
Interest rate	**(63)**	—	—	—	**(63)**
	(69)	—	**(1)**	**(11)**	**(81)**
Total Derivative Liabilities	**(76)**	—	**(2)**	**(118)**	**(196)**
Total Derivatives	**(74)**	**1**	**13**	**61**	**1**

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, 2018 is as follows:

at December 31, 2018 (millions of Canadian $)	Cash Flow Hedges	Fair Value Hedges	Net Investment Hedges	Held for Trading	Total Fair Value of Derivative Instruments[1]
Other current assets (Note 7)					
Commodities[2]	1	—	—	716	717
Foreign exchange	—	—	16	1	17
Interest rate	3	—	—	—	3
	4	—	16	717	737
Intangible and other assets (Note 13)					
Commodities[2]	1	—	—	50	51
Foreign exchange	—	—	1	—	1
Interest rate	8	1	—	—	9
	9	1	1	50	61
Total Derivative Assets	13	1	17	767	798
Accounts payable and other (Note 15)					
Commodities[2]	(4)	—	—	(622)	(626)
Foreign exchange	—	—	(105)	(188)	(293)
Interest rate	—	(3)	—	—	(3)
	(4)	(3)	(105)	(810)	(922)
Other long-term liabilities (Note 16)					
Commodities[2]	—	—	—	(28)	(28)
Foreign exchange	—	—	(2)	—	(2)
Interest rate	(11)	(1)	—	—	(12)
	(11)	(1)	(2)	(28)	(42)
Total Derivative Liabilities	(15)	(4)	(107)	(838)	(964)
Total Derivatives	(2)	(3)	(90)	(71)	(166)

1 Fair value equals carrying value.
2 Includes purchases and sales of power, natural gas and liquids.

The majority of derivative instruments held for trading have been entered into for risk management purposes and all are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

Derivatives in fair value hedging relationships

The following table details amounts recorded on the Consolidated balance sheet in relation to cumulative adjustments for fair value hedges included in the carrying amount of the hedged liabilities:

at December 31	Carrying amount		Fair value hedging adjustments[1]	
(millions of Canadian $)	2019	2018	2019	2018
Current portion of long-term debt	**—**	(748)	**—**	3
Long-term debt	**(260)**	(273)	**(1)**	—
	(260)	(1,021)	**(1)**	3

1 At December 31, 2019 and 2018, adjustments for discontinued hedging relationships included in these balances were nil.

Notional and Maturity Summary

The maturity and notional amount or quantity outstanding related to the Company's derivative instruments excluding hedges of the net investment in foreign operations is as follows:

at December 31, 2019	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Purchases[1]	**492**	**14**	**39**	**—**	**—**
Sales[1]	**2,089**	**22**	**53**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**3,153**	**1,600**
Millions of Mexican pesos	**—**	**—**	**—**	**800**	**—**
Maturity dates	**2020-2024**	**2020-2027**	**2020**	**2020**	**2020-2030**

1 Volumes for power, natural gas and liquids derivatives are in GWh, Bcf and MMBbls respectively.

at December 31, 2018	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Purchases[1]	23,865	44	59	—	—
Sales[1]	17,689	56	79	—	—
Millions of U.S. dollars	—	—	—	3,862	1,650
Maturity dates	2019-2023	2019-2027	2019	2019	2019-2030

1 Volumes for power, natural gas and liquids derivatives are in GWh, Bcf and MMBbls respectively.

Unrealized and Realized (Losses)/Gains on Derivative Instruments

The following summary does not include hedges of the net investment in foreign operations.

year ended December 31 (millions of Canadian $)	2019	2018	2017
Derivative instruments held for trading[1]			
Amount of unrealized (losses)/gains in the year			
Commodities[2]	**(111)**	28	62
Foreign exchange	**245**	(248)	88
Interest rate	**—**	—	(1)
Amount of realized gains/(losses) in the year			
Commodities	**378**	351	(107)
Foreign exchange	**(70)**	(24)	18
Interest rate	**—**	—	1
Derivative instruments in hedging relationships			
Amount of realized (losses)/gains in the year			
Commodities	**(6)**	(1)	23
Foreign exchange	**—**	—	5
Interest rate	**2**	(1)	1

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

2 In 2019, 2018 and 2017, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

Derivatives in cash flow hedging relationships

The components of OCI (Note 23) 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)	2019	2018	2017
Change in fair value of derivative instruments recognized in OCI[1]			
Commodities	**(15)**	(1)	(1)
Interest rate	**(63)**	(13)	4
	(78)	(14)	3

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI and AOCI.

Effect of fair value and cash flow hedging relationships

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

year ended December 31 (millions of Canadian $)	2019	2018	2017
Fair Value Hedges			
Interest rate contracts[1]			
Hedged items	**(19)**	(71)	(74)
Derivatives designated as hedging instruments	**1**	(4)	1
Cash Flow Hedges			
Reclassification of (losses)/gains on derivative instruments from AOCI to net income[2,3]			
Interest rate contracts[1]	**(12)**	(22)	(17)
Commodity contracts[4]	**(7)**	(5)	20

1 Presented within Interest expense in the Consolidated statement of income.
2 Refer to Note 23, Other comprehensive (loss)/income and accumulated other comprehensive loss, for the components of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests.
3 There are no amounts recognized in earnings that were excluded from effectiveness testing.
4 Presented within Revenues (Power and Storage) in the Consolidated statement of income.

Offsetting of derivative instruments

The Company enters into derivative contracts with the right to offset in the normal course of business as well as in the event of default. TC Energy has no master netting agreements, however, similar contracts are entered into containing rights to offset. The Company has elected to present the fair value of derivative instruments with the right to offset on a gross basis on the Consolidated balance sheet. The following tables show the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis:

at December 31, 2019 (millions of Canadian $)	**Gross Derivative Instruments**	**Amounts Available for Offset**[1]	**Net Amounts**
Derivative instrument assets			
Commodities	**118**	**(76)**	**42**
Foreign exchange	**76**	**(5)**	**71**
Interest rate	**3**	**(1)**	**2**
	197	**(82)**	**115**
Derivative instrument liabilities			
Commodities	**(125)**	**76**	**(49)**
Foreign exchange	**(5)**	**5**	**—**
Interest rate	**(66)**	**1**	**(65)**
	(196)	**82**	**(114)**

1 Amounts available for offset do not include cash collateral pledged or received.

at December 31, 2018 (millions of Canadian $)	**Gross Derivative Instruments**	**Amounts Available for Offset**[1]	**Net Amounts**
Derivative instrument assets			
Commodities	768	(626)	142
Foreign exchange	18	(18)	—
Interest rate	12	(4)	8
	798	(648)	150
Derivative instrument liabilities			
Commodities	(654)	626	(28)
Foreign exchange	(295)	18	(277)
Interest rate	(15)	4	(11)
	(964)	648	(316)

1 Amounts available for offset do not include cash collateral pledged or received.

With respect to the derivative instruments presented above, the Company provided cash collateral of $58 million and letters of credit of $25 million at December 31, 2019 (2018 – $143 million and $22 million, respectively) to its counterparties. At December 31, 2019, the Company held no cash collateral and no letters of credit (2018 – nil and $1 million, respectively) from counterparties on asset exposures.

Credit-risk-related contingent features of derivative instruments

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. The Company may also need to provide collateral if the fair value of its derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at December 31, 2019, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $4 million (2018 – $6 million), for which the Company has provided no collateral in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on December 31, 2019, the Company would have been required to provide collateral of $4 million (2018 – $6 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	This category includes interest rate and foreign exchange derivative assets and liabilities where fair value is determined using the income approach and commodity derivatives where fair value is determined using the market approach. Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers.
Level III	This category mainly includes long-dated commodity transactions in certain markets where liquidity is low and the Company uses the most observable inputs available or, if not available, long-term broker quotes to estimate the fair value for these transactions. There is uncertainty caused by using unobservable market data which may not accurately reflect possible future changes in fair value.

The fair value of the Company's derivative assets and liabilities measured on a recurring basis, including both current and non-current portions, are categorized as follows:

at December 31, 2019 (millions of Canadian $)	**Quoted Prices in Active Markets (Level I)**	**Significant Other Observable Inputs (Level II)**[1]	**Significant Unobservable Inputs (Level III)**[1]	**Total**
Derivative Instrument Assets				
Commodities	**81**	**37**	**—**	**118**
Foreign exchange	**—**	**76**	**—**	**76**
Interest rate	**—**	**3**	**—**	**3**
Derivative Instrument Liabilities				
Commodities	**(77)**	**(41)**	**(7)**	**(125)**
Foreign exchange	**—**	**(5)**	**—**	**(5)**
Interest rate	**—**	**(66)**	**—**	**(66)**
	4	**4**	**(7)**	**1**

1 There were no transfers from Level II to Level III for the year ended December 31, 2019.

at December 31, 2018 (millions of Canadian $)	**Quoted Prices in Active Markets (Level I)**	**Significant Other Observable Inputs (Level II)**[1]	**Significant Unobservable Inputs (Level III)**[1]	**Total**
Derivative Instrument Assets				
Commodities	581	187	—	768
Foreign exchange	—	18	—	18
Interest rate	—	12	—	12
Derivative Instrument Liabilities				
Commodities	(555)	(95)	(4)	(654)
Foreign exchange	—	(295)	—	(295)
Interest rate	—	(15)	—	(15)
	26	(188)	(4)	(166)

1 There were no transfers from Level II to Level III for the year ended December 31, 2018.

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)	**2019**	**2018**
Balance at beginning of year	**(4)**	(7)
Transfers out of Level III	**4**	5
Total (losses)/gains included in Net income	**(3)**	8
Total losses included in OCI	**(4)**	—
Settlements	**—**	(9)
Foreign exchange	**—**	(1)
Balance at end of year[1]	**(7)**	(4)

1 Revenues include unrealized losses of $3 million attributed to derivatives in the Level III category that were still held at December 31, 2019 (2018 – unrealized losses of $5 million).

26. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian $)	2019	2018	2017
Decrease/(increase) in Accounts receivable	**31**	(69)	(576)
Increase in Inventories	**(42)**	(49)	(38)
Decrease in Assets held for sale	**—**	—	14
(Increase)/decrease in Other current assets	**(15)**	45	189
Increase/(decrease) in Accounts payable and other	**352**	(70)	151
(Decrease)/increase in Accrued interest	**(33)**	41	12
Decrease in Liabilities related to Assets held for sale	**—**	—	(25)
Decrease/(increase) in Operating Working Capital	**293**	(102)	(273)

27. ACQUISITIONS AND DISPOSITIONS

U.S. Natural Gas Pipelines

Columbia Midstream Assets

On August 1, 2019, TC Energy completed the sale of certain Columbia midstream assets to a third party for approximately US$1.3 billion before post-closing adjustments.

The Company recorded a pre-tax gain on sale of $21 million ($152 million after-tax loss) including the impact of $4 million of foreign currency translation gains that were reclassified from AOCI to net income and the release of $595 million of Columbia goodwill allocated to these assets that is not deductible for income tax purposes. The pre-tax gain is included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income. This sale did not include any interest in Columbia Energy Ventures Company, the Company's minerals business in the Appalachian basin.

Iroquois Gas Transmission System and Portland Natural Gas Transmission System

In June 2017, the Company 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, the Company closed the sale of its remaining 11.81 per cent interest in Portland to TC PipeLines, LP. Proceeds from these transactions were US$765 million, before post-closing adjustments, and were comprised of US$597 million in cash and US$168 million representing a proportionate share of Iroquois and Portland debt.

Liquids Pipelines

Northern Courier

On July 17, 2019, TC Energy completed the sale of an 85 per cent equity interest in Northern Courier pipeline to a third party for gross proceeds of $144 million before post-closing adjustments resulting in a pre-tax gain of $69 million after recording the Company's remaining 15 per cent interest at fair value. The pre-tax gain is included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income. On an after-tax basis, the gain of $115 million reflects the utilization of previously unrecognized tax loss benefits. Preceding the equity sale, Northern Courier pipeline issued $1.0 billion of long-term, non-recourse debt with all proceeds paid to TC Energy.

TC Energy remains the operator of the Northern Courier pipeline and is using the equity method to account for its remaining 15 per cent interest in the Company's consolidated financial statements.

Power and Storage

Coolidge Generating Station

In December 2018, the Company entered into an agreement to sell its Coolidge generating station in Arizona to SWG Coolidge Holdings, LLC (SWG). Salt River Project Agriculture Improvement and Power District (SRP), the PPA counterparty, subsequently exercised its contractual right of first refusal (ROFR) on a sale to a third party and the Company terminated the agreement with SWG.

On May 21, 2019, the Company completed the sale to SRP, as per the terms of their ROFR, for proceeds of US$448 million before post-closing adjustments. As a result, the Company recorded a pre-tax gain on sale of $68 million ($54 million after tax) including the impact of $9 million of foreign currency translation gains which were reclassified from AOCI to net income. The pre-tax gain is included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income.

Cartier Wind

In October 2018, the Company completed the sale of its 62 per cent interest in the Cartier Wind power facilities to Innergex Renewable Energy Inc for proceeds of $630 million before post-closing adjustments. As a result, the Company recorded a gain on sale of $170 million ($143 million after tax) which is included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income.

Ontario Solar Assets

In December 2017, the Company completed the sale of its Ontario solar assets to a third party for proceeds of $541 million before post-closing adjustments. As a result, the Company recorded a gain on sale of $127 million ($136 million after tax) which is included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income.

U.S. Northeast Power Assets

In 2018, upon finalizing its 2017 annual tax returns for its U.S. operations, the Company recorded a $27 million income tax recovery related to the sale of its U.S. Northeast power generation assets.

In April 2017, the Company completed the sale of TC Hydro for proceeds of approximately US$1.07 billion before post-closing adjustments and recorded a gain on sale of $715 million ($440 million after tax), including the impact of $5 million of foreign currency translation gains which were reclassified from AOCI to net income.

In June 2017, the Company completed the sale of Ravenswood, Ironwood, Kibby Wind and Ocean State Power for proceeds of approximately US$2.029 billion before post-closing adjustments. In 2016, the Company recorded a loss of $829 million ($863 million after tax) which included the impact of $70 million of foreign currency translation gains that were reclassified from AOCI to net income on close. The Company recorded an additional loss on sale of $211 million ($167 million after tax) in 2017 which included $2 million in foreign currency translation gains. This additional loss primarily related to adjustments to the purchase price and repair costs for an unplanned outage at Ravenswood prior to close of the sale.

Gains and losses from these sales were included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income.

28. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

TC Energy and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business. Purchases under these contracts in 2019 were $236 million (2018 – $207 million; 2017 – $214 million).

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, 2019, TC Energy had the following capital expenditure commitments:

- approximately $4.5 billion for its Canadian natural gas pipelines, primarily related to construction costs associated with the Coastal GasLink pipeline and NGTL System expansion projects. Upon close of the sale of a 65 per cent interest in Coastal GasLink and establishment of a secured construction credit facility, project commitments will be predominantly funded by project-level financing and equity partners. Refer to Note 8, Plant, property and equipment, for additional information
- approximately $0.1 billion for its U.S. natural gas pipelines, primarily related to construction costs associated with Columbia Gas and ANR pipeline projects
- approximately $0.2 billion for its Mexico natural gas pipelines, primarily related to construction of the Villa de Reyes and Tula pipeline projects
- approximately $0.2 billion for its Liquids pipelines, primarily related to the development of Keystone XL
- approximately $0.7 billion for its Power and Storage business, primarily related to the Company's proportionate share of commitments for Bruce Power's life extension program.

Contingencies

TC Energy is subject to laws and regulations governing environmental quality and pollution control. As at December 31, 2019, the Company had accrued approximately $39 million (2018 – $40 million) related to operating facilities, which represents the present value of the estimated future amount it expects to spend to remediate the sites. However, additional liabilities may be incurred as assessments take place and remediation efforts continue.

TC Energy and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. The amounts involved in such proceedings are not reasonably estimable as the final outcome of such legal proceedings cannot be predicted with certainty. It is the opinion of management that the ultimate resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

Guarantees

As part of its role as operator of the Northern Courier pipeline, TC Energy has guaranteed the financial performance of the pipeline related to delivery and terminalling of bitumen and diluent and contingent financial obligations under sub-lease agreements.

TC Energy and its partner on the Sur de Texas pipeline, IEnova, have jointly guaranteed the financial performance of the entity which owns the pipeline. Such agreements include a guarantee and a letter of credit which are primarily related to construction services and the delivery of natural gas.

TC Energy and its joint venture partner on Bruce Power, BPC Generation Infrastructure Trust, have each severally guaranteed certain contingent financial obligations of Bruce Power related to a lease agreement and contractor and supplier services.

The Company and its partners in certain other jointly-owned entities have either (i) jointly and severally, (ii) jointly, (iii) severally or (iv) exclusively 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 TC Energy under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

The carrying value of these guarantees has been recorded in Accounts payable and other and Other long-term liabilities on the Consolidated balance sheet. Information regarding the Company's guarantees is as follows:

		2019		2018	
at December 31 (millions of Canadian $)	**Term**	**Potential Exposure**[1]	**Carrying Value**	**Potential Exposure**[1]	**Carrying Value**
Northern Courier pipeline	to 2055	**300**	**27**	—	—
Sur de Texas	to 2020	**109**	**—**	183	1
Bruce Power	to 2021	**88**	**—**	88	—
Other jointly-owned entities	to 2059	**100**	**10**	104	11
		597	**37**	375	12

1 TC Energy's share of the potential estimated current or contingent exposure.

29. CORPORATE RESTRUCTURING COSTS

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

Cumulatively to December 31, 2019, the Company has incurred costs of $86 million for employee severance and $61 million for lease commitments, net of $158 million related to costs that were recoverable through regulatory and tolling structures. The remaining lease commitments provision at December 31, 2019 is expected to be fully realized by 2027.

Changes in the restructuring liability were as follows:

(millions of Canadian $)	Employee Severance	Lease Commitments	Total
Restructuring liability as at December 31, 2017	9	53	62
Restructuring charges[1]	—	42	42
Accretion expense	—	1	1
Cash payments	(9)	(15)	(24)
Restructuring liability as at December 31, 2018	—	81	81
Accretion expense	**—**	**2**	**2**
Cash payments	**—**	**(14)**	**(14)**
Restructuring liability as at December 31, 2019	**—**	**69**	**69**

1 At December 31, 2018, the Company recorded an additional $21 million in Plant operating costs and other in the Consolidated statement of income and $21 million as a regulatory asset on the Consolidated balance sheet related to costs that are recoverable through regulatory and tolling structures in future periods.

30. VARIABLE INTEREST ENTITIES

A VIE is a legal entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support or is structured such that equity investors lack the ability to make significant decisions relating to the entity's operations through voting rights or do not substantively participate in the gains and losses of the entity.

In the normal course of business, the Company consolidates VIEs in which it has a variable interest and for which it is considered to be the primary beneficiary. VIEs in which the Company has a variable interest but is not the primary beneficiary are considered non-consolidated VIEs and are accounted for as equity investments.

Consolidated VIEs

The Company's consolidated VIEs consist of legal entities where the Company is the primary beneficiary. As the primary beneficiary, the Company has the power, through voting or similar rights, to direct the activities of the VIE that most significantly impact economic performance including purchasing or selling significant assets; maintenance and operations of assets; incurring additional indebtedness; or determining the strategic operating direction of the entity. In addition, the Company has the obligation to absorb losses or the right to receive benefits from the consolidated VIE that could potentially be significant to the VIE.

A significant portion of the Company's assets are held through VIEs in which the Company holds a 100 per cent voting interest, the VIE meets the definition of a business and the VIE's assets can be used for general corporate purposes. The consolidated VIEs whose assets cannot be used for purposes other than for the settlement of the VIE's obligations, or are not considered a business, are as follows:

at December 31 (millions of Canadian $)	2019	2018
ASSETS		
Current Assets		
Cash and cash equivalents	**106**	45
Accounts receivable	**88**	79
Inventories	**27**	24
Other	**8**	13
	229	161
Plant, Property and Equipment	**3,050**	3,026
Equity Investments	**785**	965
Goodwill	**431**	453
Intangible and Other Assets	**—**	8
	4,495	4,613
LIABILITIES		
Current Liabilities		
Accounts payable and other	**70**	88
Accrued interest	**21**	24
Current portion of long-term debt	**187**	79
	278	191
Regulatory Liabilities	**45**	43
Other Long-Term Liabilities	**9**	3
Deferred Income Tax Liabilities	**9**	13
Long-Term Debt	**2,694**	3,125
	3,035	3,375

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 $)	2019	2018
Balance sheet		
Equity investments[1]	**4,720**	4,575
Off-balance sheet		
Potential exposure to guarantees	**466**	170
Maximum exposure to loss	**5,186**	4,745

1 Includes equity investment in Portlands Energy Centre classified as Assets held for sale as at December 31, 2019. Refer to Note 6, Assets held for sale, for additional information.