Quarterly report to shareholders

Third quarter 2019

Financial highlights

	three months ended September 30		nine months ended September 30	
(millions of $, except per share amounts)	**2019**	**2018**	**2019**	**2018**
Income				
Revenues	**3,133**	3,156	**9,992**	9,775
Net income attributable to common shares	**739**	928	**2,868**	2,447
per common share – basic and diluted	**$0.79**	$1.02	**$3.09**	$2.72
Comparable EBITDA[1]	**2,344**	2,056	**7,051**	6,110
Comparable earnings[1]	**970**	902	**2,881**	2,534
per common share[1]	**$1.04**	$1.00	**$3.11**	$2.82
Cash flows				
Net cash provided by operations	**1,585**	1,299	**5,256**	4,516
Comparable funds generated from operations[1]	**1,802**	1,571	**5,292**	4,641
Comparable distributable cash flow[1]	**1,657**	1,413	**4,830**	4,158
per common share[1]	**$1.78**	$1.56	**$5.21**	$4.63
Capital spending[2]	**2,135**	2,798	**6,429**	7,491
Dividends declared				
Per common share	**$0.75**	$0.69	**$2.25**	$2.07
Basic common shares outstanding (millions)				
– weighted average for the period	**932**	906	**927**	898
– issued and outstanding at end of period	**934**	914	**934**	914

1 Comparable EBITDA, comparable earnings, comparable earnings per common share, comparable funds generated from operations, comparable distributable cash flow and comparable distributable cash flow per common share are all non-GAAP measures. Refer to the Non-GAAP measures section for more information.

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

Management's discussion and analysis

October 31, 2019

On May 3, 2019, TransCanada Corporation changed its name to TC Energy Corporation (TC Energy).

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TC Energy. It discusses our business, operations, financial position, risks and other factors for the three and nine months ended September 30, 2019, and should be read with the accompanying unaudited Condensed consolidated financial statements for the three and nine months ended September 30, 2019, which have been prepared in accordance with U.S. GAAP.

This MD&A should also be read in conjunction with our December 31, 2018 audited Consolidated financial statements and notes and the MD&A in our 2018 Annual Report. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in our 2018 Annual Report. Certain comparative figures have been adjusted to reflect the current period's presentation.

FORWARD-LOOKING INFORMATION

We disclose forward-looking information to help current and potential investors understand management's assessment of our future plans and financial outlook, and our future prospects overall.

Statements that are ***forward-looking*** are based on certain assumptions and on what we know and expect today and generally include words like ***anticipate, expect, believe, may, will, should, estimate*** or other similar words.

Forward-looking statements in this MD&A include information about the following, among other things:

- our financial and operational performance, including the performance of our subsidiaries
- expectations about strategies and goals for growth and expansion
- expected cash flows and future financing options available, including portfolio management
- expected dividend growth
- expected access to and cost of capital
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures and contractual obligations
- expected regulatory processes and outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- expected impact of future tax and accounting changes, commitments and contingent liabilities
- expected industry, market and economic conditions.

Forward-looking statements do not guarantee future performance. Actual events and results could be significantly different because of assumptions, risks or uncertainties related to our business or events that happen after the date of this MD&A.

Our forward-looking information is based on the following key assumptions, and subject to the following risks and uncertainties:

Assumptions

- regulatory decisions and outcomes
- planned and unplanned outages and the use of our pipeline, power and storage assets
- integrity and reliability of our assets
- anticipated construction costs, schedules and completion dates
- access to capital markets, including portfolio management
- expected industry, market and economic conditions
- inflation rates and commodity prices
- interest, tax and foreign exchange rates
- nature and scope of hedging.

Risks and uncertainties

- our ability to successfully implement our strategic priorities and whether they will yield the expected benefits
- our ability to implement a capital allocation strategy aligned with maximizing shareholder value
- the operating performance of our pipeline, power and storage assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the amount of capacity payments and revenues from our power generation assets due to plant availability
- production levels within supply basins
- construction and completion of capital projects
- costs for labour, equipment and materials
- the availability and market prices of commodities
- access to capital markets on competitive terms
- interest, tax and foreign exchange rates
- performance and credit risk of our counterparties
- regulatory decisions and outcomes of legal proceedings, including arbitration and insurance claims
- changes in environmental and other laws and regulations
- our ability to effectively anticipate and assess changes to government policies and regulations
- competition in the pipeline, power and storage sectors
- unexpected or unusual weather
- acts of civil disobedience
- cyber security and technological developments
- economic conditions in North America as well as globally.

You can read more about these factors and others in this MD&A and in other reports we have filed with Canadian securities regulators and the SEC, including the MD&A in our 2018 Annual Report.

As actual results could vary significantly from the forward-looking information, you should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events, unless we are required to by law.

FOR MORE INFORMATION

You can find more information about TC Energy in our Annual Information Form and other disclosure documents, which are available on SEDAR (www.sedar.com).

NON-GAAP MEASURES

This MD&A references the following non-GAAP measures:

- comparable EBITDA
- comparable EBIT
- comparable earnings
- comparable earnings per common share
- funds generated from operations
- comparable funds generated from operations
- comparable distributable cash flow
- comparable distributable cash flow per common share.

These measures do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to similar measures presented by other entities.

Comparable measures

We calculate comparable measures by adjusting certain GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period. Except as otherwise described herein, these comparable measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable.

Our decision not to adjust for a specific item is subjective and made after careful consideration. Specific items may include:

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

We exclude the unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives generally provide effective economic hedges but do not meet the criteria for hedge accounting. As a result, the changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them reflective of our underlying operations.

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

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

Comparable EBITDA and comparable EBIT

Comparable EBITDA represents segmented earnings adjusted for certain specific items, excluding non-cash charges for depreciation and amortization. We use comparable EBITDA as a measure of our earnings from ongoing operations as it is a useful indicator of our performance and is also presented on a consolidated basis. Comparable EBIT represents segmented earnings adjusted for specific items. Comparable EBIT is an effective tool for evaluating trends in each segment.

Comparable earnings and comparable earnings per common share

Comparable earnings represents earnings or losses attributable to common shareholders on a consolidated basis, adjusted for specific items. Comparable earnings is comprised of segmented earnings, Interest expense, AFUDC, Interest income and other, Income taxes, Non-controlling interests and Preferred share dividends, adjusted for specific items. Refer to the Consolidated results section for reconciliations to net income attributable to common shares and net income per common share.

Funds generated from operations and comparable funds generated from operations

Funds generated from operations reflects net cash provided by operations before changes in operating working capital. We believe it is a useful measure of our consolidated operating cash flow because it does not include fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period, and is used to provide a consistent measure of the cash generating performance of our assets. Comparable funds generated from operations is adjusted for the cash impact of specific items. Refer to the Financial condition section for a reconciliation to net cash provided by operations.

Comparable distributable cash flow and comparable distributable cash flow per common share

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

Maintenance capital expenditures are expenditures incurred to maintain our operating capacity, asset integrity and reliability, and include amounts paid for our proportionate share of maintenance capital expenditures on our equity investments. We have the opportunity to recover effectively all of our pipeline maintenance capital expenditures in Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Liquids Pipelines through tolls. As such, our presentation of comparable distributable cash flow and comparable distributable cash flow per common share only includes a reduction for non-recoverable maintenance capital expenditures in their respective calculations.

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

Consolidated results – third quarter 2019

As of first quarter 2019, the previously disclosed Energy segment has been renamed the Power and Storage segment.

	three months ended September 30		nine months ended September 30	
(millions of $, except per share amounts)	**2019**	2018	**2019**	2018
Canadian Natural Gas Pipelines	**283**	267	**794**	800
U.S. Natural Gas Pipelines	**626**	545	**2,081**	1,734
Mexico Natural Gas Pipelines	**125**	127	**354**	382
Liquids Pipelines	**491**	316	**1,493**	1,047
Power and Storage	**27**	223	**353**	464
Corporate	**33**	(68)	**(1)**	(77)
Total segmented earnings	**1,585**	1,410	**5,074**	4,350
Interest expense	**(573)**	(577)	**(1,747)**	(1,662)
Allowance for funds used during construction	**120**	147	**358**	365
Interest income and other	**(19)**	168	**250**	139
Income before income taxes	**1,113**	1,148	**3,935**	3,192
Income tax expense	**(274)**	(120)	**(727)**	(394)
Net income	**839**	1,028	**3,208**	2,798
Net income attributable to non-controlling interests	**(59)**	(59)	**(217)**	(229)
Net income attributable to controlling interests	**780**	969	**2,991**	2,569
Preferred share dividends	**(41)**	(41)	**(123)**	(122)
Net income attributable to common shares	**739**	928	**2,868**	2,447
Net income per common share – basic and diluted	**$0.79**	$1.02	**$3.09**	$2.72

Net income attributable to common shares decreased by $189 million or $0.23 per common share for the three months ended September 30, 2019, and increased by $421 million or $0.37 per common share for the nine months ended September 30, 2019, compared to the same periods in 2018. Net income per common share reflects the dilutive impact of common shares issued under our DRP in 2018 and 2019 and our Corporate ATM program in 2018.

Net income in both periods included unrealized gains and losses from changes in risk management activities which we excluded along with other specific items as noted below to arrive at comparable earnings.

2019 results included:

- an after-tax loss of $133 million at September 30, 2019 related to the Ontario natural gas-fired power plants held for sale. The total after-tax loss on this sale is expected to be $231 million. The remaining loss primarily reflects the residual costs to be incurred until Napanee is placed in service, including capitalized interest, and will be recorded on or before closing of the transaction, which is anticipated by the end of first quarter 2020
- an after-tax loss of $133 million related to the sale of certain Columbia Midstream assets in August 2019
- an after-tax gain of $115 million related to the partial sale of Northern Courier in July 2019
- an after-tax gain of $54 million related to the sale of our Coolidge generating station in May 2019
- a deferred tax benefit of $32 million related to the impact of an Alberta corporate income tax rate reduction on our Canadian businesses not subject to rate-regulated accounting in June 2019
- an after-tax loss of $6 million for the nine months ended September 30, 2019 related to the remainder of our U.S. Northeast power marketing contracts which were sold in May 2019.

Refer to the Recent developments section for additional information regarding the above noted dispositions.

2018 results included:

- after-tax income of $8 million and $3 million for the three and nine months ended September 30, 2018 related to our U.S. Northeast power marketing contracts.

These amounts have been excluded from comparable earnings as we do not consider these transactions or adjustments to be a part of our underlying operations.

A reconciliation of net income attributable to common shares to comparable earnings is shown in the following table.

RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS

	three months ended September 30		nine months ended September 30	
(millions of $, except per share amounts)	**2019**	**2018**	**2019**	**2018**
Net income attributable to common shares	**739**	928	**2,868**	2,447
Specific items (net of tax):				
Loss on sale of Columbia Midstream assets	**133**	—	**133**	—
Loss on Ontario natural gas-fired power plants held for sale	**133**	—	**133**	—
Gain on partial sale of Northern Courier	**(115)**	—	**(115)**	—
Gain on sale of Coolidge generating station	**—**	—	**(54)**	—
Alberta corporate income tax rate reduction	**—**	—	**(32)**	—
U.S. Northeast power marketing contracts	**—**	(8)	**6**	(3)
Risk management activities[1]	**80**	(18)	**(58)**	90
Comparable earnings	**970**	902	**2,881**	2,534
Net income per common share	**$0.79**	$1.02	**$3.09**	$2.72
Specific items (net of tax):				
Loss on sale of Columbia Midstream assets	**0.14**	—	**0.14**	—
Loss on Ontario natural gas-fired power plants held for sale	**0.14**	—	**0.14**	—
Gain on partial sale of Northern Courier	**(0.12)**	—	**(0.12)**	—
Gain on sale of Coolidge generating station	**—**	—	**(0.06)**	—
Alberta corporate income tax rate reduction	**—**	—	**(0.03)**	—
U.S. Northeast power marketing contracts	**—**	(0.01)	**0.01**	—
Risk management activities	**0.09**	(0.01)	**(0.06)**	0.10
Comparable earnings per common share	**$1.04**	$1.00	**$3.11**	$2.82

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Risk management activities	three months ended September 30		nine months ended September 30	
(millions of $)	**2019**	**2018**	**2019**	**2018**
Canadian Power	**(1)**	—	**(1)**	3
U.S. Power	**—**	31	**(52)**	(31)
Liquids marketing	**(70)**	(65)	**(36)**	(10)
Natural Gas Storage	**(3)**	—	**(8)**	(6)
Foreign exchange	**(31)**	60	**176**	(79)
Income tax attributable to risk management activities	**25**	(8)	**(21)**	33
Total unrealized (losses)/gains from risk management activities	**(80)**	18	**58**	(90)

COMPARABLE EBITDA TO COMPARABLE EARNINGS

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

	three months ended September 30		nine months ended September 30	
(millions of $, except per share amounts)	**2019**	**2018**	**2019**	**2018**
Comparable EBITDA				
Canadian Natural Gas Pipelines	**572**	522	**1,656**	1,561
U.S. Natural Gas Pipelines	**796**	715	**2,625**	2,223
Mexico Natural Gas Pipelines	**153**	153	**440**	455
Liquids Pipelines	**575**	467	**1,720**	1,311
Power and Storage	**252**	207	**622**	585
Corporate	**(4)**	(8)	**(12)**	(25)
Comparable EBITDA	**2,344**	2,056	**7,051**	6,110
Depreciation and amortization	**(610)**	(564)	**(1,839)**	(1,669)
Interest expense	**(573)**	(577)	**(1,747)**	(1,662)
Allowance for funds used during construction	**120**	147	**358**	365
Interest income and other included in comparable earnings	**49**	48	**85**	166
Income tax expense included in comparable earnings	**(260)**	(108)	**(687)**	(425)
Net income attributable to non-controlling interests	**(59)**	(59)	**(217)**	(229)
Preferred share dividends	**(41)**	(41)	**(123)**	(122)
Comparable earnings	**970**	902	**2,881**	2,534
Comparable earnings per common share	**$1.04**	$1.00	**$3.11**	$2.82

Comparable EBITDA – 2019 versus 2018

Comparable EBITDA increased by $288 million for the three months ended September 30, 2019 compared to the same period in 2018 primarily due to the net effect of the following:

- higher contribution from Liquids Pipelines primarily due to higher volumes on the Keystone Pipeline System and increased earnings from liquids marketing activities, partially offset by the sale of an 85 per cent equity interest in Northern Courier in July 2019
- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by decreased earnings from Bison (wholly-owned by TC PipeLines, LP) and from the sale of certain Columbia Midstream assets in August 2019
- higher contribution from Canadian Natural Gas Pipelines mainly due to the Canadian Mainline recovery of increased depreciation and higher incentive earnings in 2019
- higher contribution from Power and Storage primarily due to increased Bruce Power results from a higher realized power price and higher output, partially offset by the sale of our interests in the Cartier Wind power facilities in fourth quarter 2018 and the sale of our Coolidge generating station in May 2019.

Comparable EBITDA increased by $941 million for the nine months ended September 30, 2019 compared to the same period in 2018 and was primarily due to the net effect of the following:

- higher contribution from Liquids Pipelines primarily due to higher volumes on the Keystone Pipeline System and increased earnings from liquids marketing activities, partially offset by decreased earnings as a result of the sale of an 85 per cent equity interest in Northern Courier in July 2019

- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by decreased earnings from Bison (wholly-owned by TC PipeLines, LP) and from the sale of certain Columbia Midstream assets in August 2019
- higher contribution from Canadian Natural Gas Pipelines mainly due to the Canadian Mainline recovery of increased depreciation and higher incentive earnings in 2019, partially offset by lower flow-through income taxes on the NGTL System as a result of accelerated tax depreciation
- higher contribution from Power and Storage primarily due to increased Bruce Power results from a higher realized power price net of lower generation due to increased outage days, partially offset by the sale of our interests in the Cartier Wind power facilities in 2018 and the sale of our Coolidge generating station in May 2019
- foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent earnings from our U.S. operations.

Due to the flow-through treatment of certain expenses including income taxes and depreciation on our Canadian rate-regulated pipelines, the accelerated tax depreciation changes in 2019 and increased depreciation expense impacts our comparable EBITDA despite having no effect on net income.

Comparable earnings – 2019 versus 2018

Comparable earnings increased by $68 million or $0.04 per common share for the three months ended September 30, 2019 compared to the same period in 2018 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher income tax expense primarily due to higher comparable earnings before income taxes and lower foreign tax rate differentials
- higher depreciation, largely in Canadian Natural Gas Pipelines which is fully recovered in tolls as reflected in the comparable EBITDA discussion above, therefore having no impact on comparable earnings. In addition, higher consolidated depreciation reflects new projects placed in service
- lower AFUDC in U.S. Natural Gas Pipelines primarily due to Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by continued investment in our NGTL System expansion and Mexico projects.

Comparable earnings increased by $347 million or $0.29 per common share for the nine months ended September 30, 2019 compared to the same period in 2018 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher income tax expense due to higher comparable earnings before income taxes and lower foreign tax rate differentials, partially offset by lower flow-through income taxes on the NGTL System
- higher depreciation, largely in Canadian Natural Gas Pipelines which is fully recovered in tolls as reflected in the increase in comparable EBITDA described above therefore having no impact on comparable earnings. In addition, higher consolidated depreciation reflects new projects placed in service
- higher interest expense primarily as a result of higher levels of short-term borrowings, the foreign exchange impact on translation of U.S. dollar-denominated interest, and long-term debt issuances, net of maturities, partially offset by higher capitalized interest
- lower interest income and other due to realized losses in 2019 compared to realized gains in 2018 on derivatives used to manage exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Comparable earnings per common share for the three and nine months ended September 30, 2019 also reflects the dilutive impact of common shares issued under our DRP in 2018 and 2019 and our Corporate ATM program in 2018.

Capital Program

We are developing quality projects under our capital program. These long-life infrastructure assets are supported by long-term commercial arrangements with creditworthy counterparties or regulated business models and are expected to generate significant growth in earnings and cash flow.

Our capital program consists of approximately $30 billion of secured projects which include commercially supported, committed projects that are either under construction, are in or are preparing to commence the permitting stage but are not yet fully approved. An additional $21 billion of projects under development are commercially supported (except where noted) but have greater uncertainty with respect to timing and estimated project costs and are subject to certain approvals. In the nine months ended September 30, 2019, we have placed approximately $8.2 billion of projects in service including Mountaineer XPress, Gulf XPress, various NGTL System expansions and the Sur de Texas and White Spruce pipelines.

Three years of maintenance capital expenditures for our businesses are included in the secured projects table. Maintenance capital expenditures on our regulated Canadian and U.S. natural gas pipelines businesses are added to rate base on which we have the opportunity to earn a return and recover these expenditures through current or future tolls, which is similar to our capacity capital projects on these pipelines. Tolling arrangements in our liquids pipelines business provide for the recovery of maintenance capital expenditures.

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

Secured projects

(billions of $)	Expected in-service date	Estimated project cost[1]	Carrying value at September 30, 2019
Canadian Natural Gas Pipelines			
Canadian Mainline	2019-2022	0.4	0.1
NGTL System[2,3]	2019	2.5	2.4
	2020	2.1	0.8
	2021	2.6	0.1
	2022+	2.8	—
Coastal GasLink[4,5]	2023	6.6	0.8
Regulated maintenance capital expenditures	2019-2021	1.8	0.4
U.S. Natural Gas Pipelines			
Columbia Gas			
Modernization II	2019-2020	US 1.1	US 0.7
Other capacity capital	2019-2022	US 1.5	US 0.1
Regulated maintenance capital expenditures	2019-2021	US 2.1	US 0.4
Mexico Natural Gas Pipelines			
Villa de Reyes	2020	US 0.9	US 0.7
Tula[6]	—	US 0.8	US 0.6
Liquids Pipelines			
Other capacity capital	2020	0.1	—
Recoverable maintenance capital expenditures	2019-2021	0.1	—
Power and Storage			
Bruce Power – life extension[7]	2019-2023	2.2	0.9
Other			
Non-recoverable maintenance capital expenditures[8]	2019-2021	0.7	0.2
		28.3	**8.2**
Foreign exchange impact on secured projects[9]		**2.0**	**0.8**
Total secured projects (Cdn$)		**30.3**	**9.0**

1 Amounts reflect our proportionate share of joint venture costs where applicable and 100 per cent of costs related to wholly-owned assets and assets held through TC PipeLines, LP.

2 The North Montney project is included in the 2019 program, although a portion of this project is expected to be placed into service in January 2020.

3 Includes $0.7 billion for the Foothills pipeline system related to the West Path Delivery Program.

4 Represents 100 per cent of required capital prior to potential joint venture partners or project financing.

5 Carrying value is net of the fourth quarter 2018 receipts from the LNG Canada participants for the reimbursement of approximately $0.5 billion of pre-FID costs pursuant to project agreements.

6 Construction of the central segment for the Tula project has been delayed due to a lack of progress to successfully complete Indigenous consultation by the Secretary of Energy. The east and west segments of Tula are being considered as part of the current renegotiation with CFE.

7 Reflects our proportionate share of the Unit 6 Major Component Replacement program costs, expected to be in service in 2023, and amounts to be invested under the Asset Management program through 2023.

8 Includes non-recoverable maintenance capital expenditures from all segments and is primarily comprised of our proportionate share of maintenance capital expenditures for Bruce Power and other Power and Storage assets.

9 Reflects U.S./Canada foreign exchange rate of 1.32 at September 30, 2019.

Projects under development

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

(billions of $)	Estimated project cost[1]	Carrying value at September 30, 2019
Canadian Natural Gas Pipelines		
NGTL System – Merrick	1.9	—
U.S. Natural Gas Pipelines		
Other capacity capital[2]	US 0.4	—
Liquids Pipelines		
Keystone XL[3]	US 8.0	US 1.0
Heartland and TC Terminals[4]	0.9	0.1
Grand Rapids Phase 2[4]	0.7	—
Keystone Hardisty Terminal[4]	0.3	0.1
Power and Storage		
Bruce Power – life extension[5]	6.0	—
	18.2	1.2
Foreign exchange impact on projects under development[6]	2.7	0.3
Total projects under development (Cdn$)	**20.9**	**1.5**

1 Amounts reflect our proportionate share of joint venture costs where applicable and 100 per cent of costs related to wholly-owned assets and assets held through TC PipeLines, LP.

2 Includes projects subject to a positive customer FID.

3 Carrying value reflects amount remaining after impairment charge recorded in 2015 along with additional amounts capitalized from January 1, 2018. A portion of the carrying value is recoverable from shippers under certain conditions.

4 Regulatory approvals have been obtained and additional commercial support is being pursued.

5 Reflects our proportionate share of Major Component Replacement program costs for Units 3, 4, 5, 7 and 8, and the remaining Asset Management program costs beyond 2023.

6 Reflects U.S./Canada foreign exchange rate of 1.32 at September 30, 2019.

Outlook

Consolidated comparable earnings

Our overall comparable earnings outlook for 2019 remains consistent with the 2018 Annual Report taking into consideration the net effect of:

- higher expected volumes on the Keystone Pipeline System as well as higher contribution from liquids marketing activities
- delays in the commencement of operations on the Napanee power plant and Sur de Texas pipeline
- uncertainty regarding the impact of final U.S. Tax Reform regulations, expected in late 2019, on the cost of financing certain of our U.S. operations
- asset sales and use of proceeds.

Consolidated capital spending

Our total capital expenditures for 2019 are expected to be approximately $9 billion on growth projects, maintenance capital expenditures and contributions to equity investments. The increase relative to the outlook in the 2018 Annual Report is primarily a result of higher spending on Napanee, the NGTL System and Mountaineer XPress as well as changes in foreign exchange rates.

Canadian Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(millions of $)	**2019**	**2018**	**2019**	**2018**
NGTL System	**311**	302	**871**	884
Canadian Mainline	**234**	195	**704**	592
Other Canadian pipelines[1]	**27**	25	**81**	85
Comparable EBITDA	**572**	522	**1,656**	1,561
Depreciation and amortization	**(289)**	(255)	**(862)**	(761)
Comparable EBIT and segmented earnings	**283**	267	**794**	800

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

Canadian Natural Gas Pipelines comparable EBIT and segmented earnings increased by $16 million and decreased by $6 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018.

Net income and comparable EBITDA for our rate-regulated Canadian natural gas pipelines are primarily affected by our approved ROE, investment base, the level of deemed common equity and incentive earnings. Changes in depreciation, financial charges and income taxes also impact comparable EBITDA but do not have a significant impact on net income as they are almost entirely recovered in revenue on a flow-through basis.

NET INCOME AND AVERAGE INVESTMENT BASE

	three months ended September 30		nine months ended September 30	
(millions of $)	**2019**	**2018**	**2019**	**2018**
Net Income				
NGTL System	**124**	101	**355**	289
Canadian Mainline	**43**	40	**129**	121
Average investment base				
NGTL System			**11,654**	9,419
Canadian Mainline			**3,677**	3,855

Net income for the NGTL System increased by $23 million and $66 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 mainly due to a higher average investment base resulting from continued system expansions. The NGTL System is operating under 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 OM&A amount and flow-through treatment of all other costs.

Net income for the Canadian Mainline increased by $3 million and $8 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018. The increase in the nine months ended September 30, 2019 is mainly due to higher incentive earnings. We did not record incentive earnings in the first nine months of 2018 pending the outcome of the Canadian Mainline 2018-2020 toll review. The NEB 2018 Decision, received in December 2018, preserved the incentive arrangement from the NEB 2014 Decision along with an approved ROE of 10.1 per cent on 40 per cent deemed equity. As a result, we recorded the 2018 full-year incentive earnings in fourth quarter 2018.

COMPARABLE EBITDA

Comparable EBITDA for the Canadian Natural Gas Pipelines increased by $50 million and $95 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 due to the net effect of:

- increased depreciation on the Canadian Mainline due to higher rates approved in the NEB 2018 Decision
- increased incentive earnings on the Canadian Mainline
- lower flow-through income taxes on the NGTL System and the Canadian Mainline as a result of the Canadian federal government's accelerated tax depreciation, enacted in June 2019, to allow businesses in Canada to deduct the cost of their investments more quickly. Due to the flow-through treatment of income taxes on our Canadian rate-regulated pipelines, this beneficial income tax change reduces our comparable EBITDA despite having no impact on net income
- increased rate base earnings on the NGTL System
- increased depreciation on the NGTL System due to additional facilities that were placed in service.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $34 million and $101 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 mainly due to the increase in composite depreciation rates approved in the Mainline NEB 2018 Decision as well as additional NGTL System facilities that were placed in service.

U.S. Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

(millions of US$, unless otherwise noted)	three months ended September 30 2019	three months ended September 30 2018	nine months ended September 30 2019	nine months ended September 30 2018
Columbia Gas	**291**	204	**906**	637
ANR	**107**	111	**373**	370
TC PipeLines, LP[1,2]	**26**	30	**88**	102
Great Lakes[3]	**15**	18	**62**	74
Midstream	**18**	42	**87**	101
Columbia Gulf	**47**	34	**131**	90
Other U.S. pipelines[4]	**21**	19	**58**	50
Non-controlling interests[5]	**79**	89	**270**	304
Comparable EBITDA	**604**	547	**1,975**	1,728
Depreciation and amortization	**(145)**	(130)	**(425)**	(380)
Comparable EBIT	**459**	417	**1,550**	1,348
Foreign exchange impact	**146**	128	**510**	386
Comparable EBIT (Cdn$)	**605**	545	**2,060**	1,734
Specific item:				
Gain on sale of Columbia Midstream assets	**21**	—	**21**	—
Segmented earnings (Cdn$)	**626**	545	**2,081**	1,734

1 Reflects our earnings from TC PipeLines, LP's ownership interests in eight natural gas pipelines as well as general and administrative costs related to TC PipeLines, LP.
2 For the three and nine months ended September 30, 2019, our ownership interest in TC PipeLines, LP was 25.5 per cent which is unchanged from the same periods in 2018.
3 Reflects our 53.55 per cent direct interest in Great Lakes. The remaining 46.45 per cent is held by TC PipeLines, LP.
4 Reflects earnings from our effective ownership in Millennium and Hardy Storage as well as general and administrative and business development costs related to our U.S. natural gas pipelines.
5 Reflects earnings attributable to portions of TC PipeLines, LP that we do not own.

U.S. Natural Gas Pipelines segmented earnings increased by $81 million and $347 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 and included a pre-tax gain of $21 million related to the sale of certain Columbia Midstream assets in August 2019 which has been excluded from comparable EBIT. Refer to the Recent developments section for further information.

In addition to the net increases in comparable EBITDA noted below, a stronger U.S. dollar in 2019 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same periods in 2018.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$57 million and US$247 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018. This was primarily the net effect of:

- increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service
- decreased earnings from Bison (wholly-owned by TC PipeLines, LP) due to 2018 customer agreements to pay out their future contracted revenues and terminate their contracts
- decreased earnings as a result of the sale of certain Columbia Midstream assets in August 2019.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US$15 million and US$45 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 mainly due to new projects placed in service, partially offset by lower depreciation as a result of the Bison (wholly-owned by TC PipeLines, LP) asset impairment in 2018 and the sale of certain Columbia Midstream assets in August 2019.

Mexico Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(millions of US$, unless otherwise noted)	**2019**	2018	**2019**	2018
Topolobampo	**40**	42	**120**	128
Tamazunchale	**31**	33	**93**	96
Mazatlán	**17**	19	**52**	58
Guadalajara	**17**	18	**49**	53
Sur de Texas[1]	**10**	4	**18**	14
Other	**—**	—	**—**	4
Comparable EBITDA	**115**	116	**332**	353
Depreciation and amortization	**(21)**	(19)	**(65)**	(56)
Comparable EBIT	**94**	97	**267**	297
Foreign exchange impact	**31**	30	**87**	85
Comparable EBIT and segmented earnings (Cdn$)	**125**	127	**354**	382

1 Represents equity income from our 60 per cent interest.

Mexico Natural Gas Pipelines comparable EBIT and segmented earnings decreased by $2 million and $28 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018. Lower EBITDA as described below was partially offset by a stronger U.S. dollar in 2019 which had a positive impact on the Canadian dollar equivalent earnings.

Comparable EBITDA for Mexico Natural Gas Pipelines decreased by US$1 million and US$21 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 mainly due to the net effect of:

- lower revenues from operations primarily as a result of changes in timing of revenue recognition in 2018
- higher equity earnings from our investment in the Sur de Texas pipeline which was placed in service on September 17, 2019, at which time recording of equity income from operations commenced. Prior to in-service, Sur de Texas equity income primarily reflected AFUDC during construction, net of interest expense on an inter-affiliate loan from TC Energy. This interest expense is fully offset in Interest income and other in the Corporate segment.

Following the execution of an amending agreement with CFE for the Sur de Texas pipeline and commencement of operations, revenue is being recognized for this pipeline at a levelized average rate over the now 35-year contract. Refer to the Recent developments section for additional information.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US$2 million and US$9 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 reflecting new assets in service and other adjustments.

Liquids Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(millions of $)	**2019**	**2018**	**2019**	**2018**
Keystone Pipeline System	**415**	350	**1,283**	1,042
Intra-Alberta pipelines	**29**	46	**109**	122
Liquids marketing and other	**131**	71	**328**	147
Comparable EBITDA	**575**	467	**1,720**	1,311
Depreciation and amortization	**(83)**	(86)	**(260)**	(254)
Comparable EBIT	**492**	381	**1,460**	1,057
Specific items:				
Gain on partial sale of Northern Courier	**69**	—	**69**	—
Risk management activities	**(70)**	(65)	**(36)**	(10)
Segmented earnings	**491**	316	**1,493**	1,047
Comparable EBIT denominated as follows:				
Canadian dollars	**88**	96	**272**	278
U.S. dollars	**306**	218	**894**	605
Foreign exchange impact	**98**	67	**294**	174
Comparable EBIT	**492**	381	**1,460**	1,057

Liquids Pipelines segmented earnings increased by $175 million and $446 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 and included the following specific items which have been excluded from our calculation of comparable EBIT:

- a pre-tax gain of $69 million related to the sale of an 85 per cent equity interest in Northern Courier. Refer to the Recent developments section for additional information
- unrealized losses from changes in the fair value of derivatives related to our liquids marketing business.

Comparable EBITDA for Liquids Pipelines increased by $108 million and $409 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018. This was primarily the net effect of:

- higher volumes on the Keystone Pipeline System
- higher contribution from liquids marketing activities due to improved margins and volumes
- contribution from the White Spruce pipeline, which went into service in May 2019
- decreased earnings as a result of the sale of an 85 per cent equity interest in Northern Courier in July 2019
- positive foreign exchange impact on the Canadian dollar equivalent earnings from our U.S. operations.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization decreased by $3 million and increased by $6 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018. The decrease in the three-month period is primarily a result of the sale of an 85 per cent equity interest in Northern Courier. The increase for the nine-month period is the net result of new facilities being placed in service and the effect of a stronger U.S. dollar, partially offset by the sale of an 85 per cent equity interest in Northern Courier.

THIRD QUARTER 2019

Power and Storage

As of first quarter 2019, the previously disclosed Energy segment has been renamed the Power and Storage segment.

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(millions of $)	**2019**	**2018**	**2019**	**2018**
Western and Eastern Power[1]	**61**	106	**228**	329
Bruce Power[1]	**193**	100	**378**	245
Natural Gas Storage and other	**2**	4	**25**	21
Business development	**(4)**	(3)	**(9)**	(10)
Comparable EBITDA	**252**	207	**622**	585
Depreciation and amortization	**(19)**	(27)	**(66)**	(92)
Comparable EBIT	**233**	180	**556**	493
Specific items:				
Loss on Ontario natural gas-fired power plants held for sale	**(202)**	—	**(202)**	—
Gain on sale of Coolidge generating station	**—**	—	**68**	—
U.S. Northeast power marketing contracts	**—**	12	**(8)**	5
Risk management activities	**(4)**	31	**(61)**	(34)
Segmented earnings	**27**	223	**353**	464

1 Includes our share of equity income from our investments in Portlands Energy and Bruce Power.

Power and Storage segmented earnings decreased by $196 million and $111 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 and included the following specific items which have been excluded from comparable EBIT:

- a pre-tax loss of $202 million recorded in third quarter 2019 related to the Ontario natural gas-fired power plants held for sale
- a pre-tax gain of $68 million related to the sale of our Coolidge generating station in May 2019
- pre-tax losses of nil and $8 million for the three and nine months ended September 30, 2019, (2018 – pre-tax gains of $12 million and $5 million, respectively) related to our U.S. Northeast power marketing contracts, the remainder of which were sold in May 2019
- unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks.

Refer to the Recent developments section for additional information regarding the above noted dispositions.

Comparable EBITDA for Power and Storage increased by $45 million and $37 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 primarily due to the net effect of:

- increased Bruce Power results mainly due to a higher realized power price and higher output due to fewer outage days for the three months ended September 30, 2019. Results increased for the nine months ended September 30, 2019 largely due to a higher realized power price, partially offset by lower volumes from greater outage days. Additional financial and operating information on Bruce Power is provided below
- decreased Western and Eastern Power results largely due to the sale of our interests in the Cartier Wind power facilities in October 2018, the sale of our Coolidge generating station in May 2019 and lower realized margins on lower generation volumes.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization decreased by $8 million and $26 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 primarily due to the cessation of depreciation on our Coolidge generating station at December 31, 2018 and our Halton Hills power plant at July 30, 2019 upon classification as held for sale as well as the sale of our interests in the Cartier Wind power facilities in October 2018.

BRUCE POWER

The following reflects our proportionate share of the components of comparable EBITDA and comparable EBIT.

	three months ended September 30		nine months ended September 30	
(millions of $, unless otherwise noted)	**2019**	**2018**	**2019**	**2018**
Equity income included in comparable EBITDA and EBIT comprised of:				
Revenues[1]	**499**	397	**1,284**	1,153
Operating expenses	**(217)**	(204)	**(660)**	(640)
Depreciation and other	**(89)**	(93)	**(246)**	(268)
Comparable EBITDA and EBIT[2]	**193**	100	**378**	245
Bruce Power – other information				
Plant availability[3]	**93%**	89%	**83%**	88%
Planned outage days	**45**	30	**291**	180
Unplanned outage days	**3**	43	**57**	77
Sales volumes (GWh)[2]	**6,321**	6,087	**16,817**	17,810
Realized power price per MWh[4]	**$78**	$67	**$75**	$67

1 Net of amounts recorded to reflect operating cost efficiencies shared with the IESO.

2 Represents our 48.4 per cent (2018 – 48.3 per cent) ownership interest in Bruce Power. Sales volumes include deemed generation.

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

4 Calculation based on actual and deemed generation. Realized power price per MWh includes realized gains and losses from contracting activities and cost flow-through items. Excludes unrealized gains and losses on contracting activities and non-electricity revenues.

Planned outage work on Units 3 and 7 was completed in the first half of 2019. Planned maintenance on Unit 5 began in August 2019 and is scheduled to be completed in fourth quarter 2019. Planned maintenance on Unit 2 is expected in fourth quarter 2019. The overall average plant availability percentage in 2019 is expected to be in the low-80 per cent range.

On April 1, 2019, Bruce Power's contract price increased from approximately $68 per MWh to a final adjusted contract price of approximately $78 per MWh including flow-through items, reflecting capital to be invested under the Unit 6 Major Component Replacement program and the Asset Management program as well as annual inflation adjustments.

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings/(losses) (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(millions of $)	2019	2018	2019	2018
Comparable EBITDA and EBIT	**(4)**	(8)	**(12)**	(25)
Specific item:				
Foreign exchange gain/(loss) – inter-affiliate loan[1]	**37**	(60)	**11**	(52)
Segmented earnings/(losses)	**33**	(68)	**(1)**	(77)

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

Corporate segmented earnings increased by $101 million for the three months ended September 30, 2019 while Corporate segmented losses decreased by $76 million for the nine months ended September 30, 2019 compared to the same periods in 2018. Segmented earnings/(losses) include foreign exchange gains and losses on a peso-denominated inter-affiliate loan to the Sur de Texas project for our proportionate share of the project's financing which are fully offset by corresponding foreign exchange losses and gains included in Interest income and other on the inter-affiliate loan receivable. These amounts have been excluded from our calculation of comparable EBIT.

Comparable EBITDA increased by $4 million and $13 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 primarily due to U.S. capital tax adjustments recorded in second quarter 2018 and decreased general and administrative costs.

OTHER INCOME STATEMENT ITEMS

Interest expense

	three months ended September 30		nine months ended September 30	
(millions of $)	2019	2018	2019	2018
Interest on long-term debt and junior subordinated notes				
Canadian dollar-denominated	**(152)**	(142)	**(440)**	(407)
U.S. dollar-denominated	**(330)**	(335)	**(989)**	(981)
Foreign exchange impact	**(106)**	(103)	**(326)**	(283)
	(588)	(580)	**(1,755)**	(1,671)
Other interest and amortization expense	**(33)**	(30)	**(121)**	(80)
Capitalized interest	**48**	33	**129**	89
Interest expense	**(573)**	(577)	**(1,747)**	(1,662)

Interest expense decreased by $4 million and increased by $85 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 primarily due to the net effect of:

- long-term debt issuances, net of maturities
- foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest
- higher levels of short-term borrowings
- higher capitalized interest primarily related to Keystone XL and Napanee.

Allowance for funds used during construction

	three months ended September 30		nine months ended September 30	
(millions of $)	**2019**	2018	**2019**	2018
Canadian dollar-denominated	**57**	27	**151**	68
U.S. dollar-denominated	**48**	91	**156**	230
Foreign exchange impact	**15**	29	**51**	67
Allowance for funds used during construction	**120**	147	**358**	365

AFUDC decreased by $27 million and $7 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018. The increase in Canadian dollar-denominated AFUDC is primarily due to capital expenditures on our NGTL System expansion projects. The decrease in U.S. dollar-denominated AFUDC is largely due to Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by continued investment in our Mexico projects.

Interest income and other

	three months ended September 30		nine months ended September 30	
(millions of $)	**2019**	2018	**2019**	2018
Interest income and other included in comparable earnings	**49**	48	**85**	166
Specific items:				
Foreign exchange (loss)/gain – inter-affiliate loan	**(37)**	60	**(11)**	52
Risk management activities	**(31)**	60	**176**	(79)
Interest income and other	**(19)**	168	**250**	139

Interest income and other decreased by $187 million for the three months ended September 30, 2019 compared to the same period in 2018 and was primarily the net effect of:

- foreign exchange losses in 2019 compared to foreign exchange gains in 2018 related to a peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture. The corresponding foreign exchange gains and losses in Sur de Texas are reflected in Income from equity investments, resulting in no net impact on net income. The offsetting currency-related gain and loss amounts are excluded from comparable earnings
- unrealized losses in 2019 compared to unrealized gains in 2018 from foreign exchange risk management activities. These amounts have been excluded from comparable earnings.

Interest income and other increased by $111 million for the nine months ended September 30, 2019 compared to the same period in 2018 and was primarily the net effect of:

- unrealized gains in 2019 compared to unrealized losses in 2018 from foreign exchange risk management activities. These amounts have been excluded from comparable earnings
- foreign exchange losses in 2019 compared to foreign exchange gains in 2018 related to a peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture. The corresponding foreign exchange gains and losses in Sur de Texas are reflected in Income from equity investments, resulting in no net impact on net income. The offsetting currency-related gain and loss amounts are excluded from comparable earnings
- realized losses in 2019 compared to realized gains in 2018 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Income tax expense

(millions of $)	three months ended September 30		nine months ended September 30	
	2019	**2018**	**2019**	**2018**
Income tax expense included in comparable earnings	**(260)**	(108)	**(687)**	(425)
Specific items:				
Gain on partial sale of Northern Courier	**46**	—	**46**	—
Loss on sale of Columbia Midstream assets	**(154)**	—	**(154)**	—
Loss on Ontario natural gas-fired power plants held for sale	**69**	—	**69**	—
Gain on sale of Coolidge generating station	**—**	—	**(14)**	—
Alberta corporate income tax rate reduction	**—**	—	**32**	—
U.S. Northeast power marketing contracts	**—**	(4)	**2**	(2)
Risk management activities	**25**	(8)	**(21)**	33
Income tax expense	**(274)**	(120)	**(727)**	(394)

Income tax expense included in comparable earnings increased by $152 million and $262 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018. This was primarily due to higher comparable earnings before income taxes and lower foreign tax rate differentials, partially offset by lower flow-through income taxes in Canadian rate-regulated pipelines.

In second quarter 2019, we recorded a $32 million income tax recovery on deferred income tax balances attributable to our Canadian businesses not subject to rate-regulated accounting due to the Alberta corporate income tax rate reduction enacted in June 2019. This has been excluded from comparable earnings.

Refer to the Recent developments section for additional information on the income tax impacts of dispositions.

Net income attributable to non-controlling interests

(millions of $)	three months ended September 30		nine months ended September 30	
	2019	**2018**	**2019**	**2018**
Net income attributable to non-controlling interests	**(59)**	(59)	**(217)**	(229)

Net income attributable to non-controlling interests for the nine months ended September 30, 2019 decreased by $12 million compared to the same period in 2018 primarily due to lower earnings in TC PipeLines, LP, partially offset by the impact of a stronger U.S. dollar in 2019 on the Canadian dollar equivalent earnings.

Preferred share dividends

(millions of $)	three months ended September 30		nine months ended September 30	
	2019	**2018**	**2019**	**2018**
Preferred share dividends	**(41)**	(41)	**(123)**	(122)

Recent developments

CANADA ENERGY REGULATOR AND THE IMPACT ASSESSMENT AGENCY OF CANADA

On August 28, 2019, the Canadian Energy Regulator Act (CER Act) came into effect, replacing the National Energy Board Act (NEB Act), and the National Energy Board (NEB) was replaced by the Canada Energy Regulator (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.

CANADIAN NATURAL GAS PIPELINES

Coastal GasLink Pipeline Project

Following the October 2018 positive FID by LNG Canada, construction activities continue along the pipeline route including the area south of Houston, B.C. which required a B.C. Supreme Court injunction for access. We expect a further decision in fourth quarter 2019 from the B.C. Supreme Court to extend the injunction to project completion.

On July 26, 2019, the NEB issued its decision affirming provincial jurisdiction for Coastal GasLink. Accordingly, construction will continue to proceed as planned under the permits granted to Coastal GasLink by the B.C. Oil and Gas Commission.

Our estimated project cost has increased from $6.2 billion to $6.6 billion due to increased scope and refinement of construction estimates for rock work and watercourse crossings. We expect the incremental cost will be incorporated into the final tolls.

TC Energy continues to advance funding plans for this pipeline project through a combination of the sale of up to 75 per cent ownership interest and arrangement of project financing, which are both proceeding as planned.

NGTL System

On October 31, 2019, we announced our West Path Delivery Program, an expansion of our NGTL System and Foothills pipeline system for incremental export capacity onto the GTN system in the Pacific Northwest. The Canadian portion of the expansion program has an estimated capital cost of $1.2 billion and consists of approximately 119 km (74 miles) of pipeline and associated facilities with in-service dates between fourth quarter 2022 and fourth quarter 2023. This Program is underpinned by approximately 275 TJ/d (258 MMcf/d) of new firm service contracts with terms that exceed 30 years.

On March 14, 2019, the NGTL System Rate Design and Services Application was filed with the NEB which included a settlement agreement negotiated with members of its Tolls, Tariff, Facilities and Procedures (TTFP) committee which represents stakeholders. The settlement is supported by the majority of members of the TTFP committee. The Application addresses rate design, terms and conditions of service for the NGTL System and a tolling methodology for the North Montney Mainline (NMML). Given the complexity of the issues raised in the Application, the NEB decided to hold a public hearing which is expected to conclude in fourth quarter 2019.

On May 16, 2019, the NEB approved the proposed NMML tolling methodology including the surcharge, as filed, on an interim basis, pending the outcome of the above Rate Design and Services Application.

In the nine months ended September 30, 2019, the NGTL System placed approximately $0.8 billion of capacity projects in service.

Canadian Mainline

In March 2019, the NEB approved Canadian Mainline tolls as filed in the January 2019 compliance filing related to the 2018-2020 Toll Review.

On May 9, 2019, we received NEB approval of the North Bay Junction Long Term Fixed Price service, as filed.

U.S. NATURAL GAS PIPELINES

Sale of Columbia Midstream Assets

On August 1, 2019, we finalized the sale of certain Columbia Midstream assets to UGI Energy Services, LLC, a subsidiary of UGI Corporation, for proceeds of approximately US$1.3 billion, before post-closing adjustments. The sale resulted in a pre-tax gain of $21 million ($133 million after-tax loss), which included the release of $595 million of Columbia's goodwill allocated to these assets that is not deductible for income tax purposes. This sale does not include any interest in Columbia Energy Ventures Company, which is our minerals business in the Appalachian basin.

Columbia Gulf Rate Settlement

Columbia Gulf and its shippers have recently agreed to a settlement-in-principle addressing all rate and service related issues raised during the settlement discussions. We plan to file an agreement with FERC before the end of the year reflecting this settlement-in-principle and precluding the need to file a general rate case as contemplated by Columbia Gulf's previous 2016 settlement. We anticipate that FERC will accept the settlement agreement and that it will be unopposed.

PHMSA Compliance Regulation

The Pipeline and Hazardous Materials Safety Administration (PHMSA) released its final rule revising the Federal Pipeline Safety Regulations. The rule updates reporting and records retention standards for gas transmission pipelines and expands the level of required integrity assessments that must be completed on certain pipeline segments outside of high consequence areas. The final rule also requires operators to review maximum allowable operating pressure records and perform specific remediation activities where records are not available. We are currently assessing the operational and financial impact related to this ruling which will become effective on July 1, 2020.

GTN XPress

In third quarter 2019, we initiated the GTN XPress project which is an integrated reliability and expansion project on the GTN system that will provide for the transport of additional volumes enabled by the West Path Delivery Program discussed above. GTN XPress is expected to be fully complete in late 2023 with an estimated total cost of US$0.3 billion.

East Lateral XPress

In second quarter 2019, we approved the East Lateral XPress project, an expansion project on the Columbia Gulf system that will connect supply to Gulf Coast LNG export markets. Subject to a positive customer FID, the anticipated in-service is 2022 with estimated project costs of US$0.3 billion.

Louisiana XPress and Grand Chenier XPress

Combined, the Louisiana XPress and Grand Chenier XPress projects will connect nearly 2 Bcf/d of supply to Gulf Coast LNG export facilities. Both projects have now obtained necessary customer approvals or waivers of conditions allowing the projects to move to the execution phase. Interim service for Louisiana XPress shippers will commence on Columbia Gulf November 1, 2019, with full in-service anticipated in 2022 and total estimated project costs of US$0.4 billion. The anticipated in-service dates for Grand Chenier XPress are in 2021 and 2022 for Phase I and II, respectively, with total estimated project costs of US$0.2 billion.

Mountaineer XPress and Gulf XPress

The Mountaineer XPress project, a Columbia Gas project transporting supply from the Marcellus and Utica shale plays to points along the system and the Leach interconnect with Columbia Gulf, was phased into service over first quarter 2019 along with Gulf XPress, a Columbia Gulf project.

MEXICO NATURAL GAS PIPELINES

CFE Arbitration

In June 2019, CFE filed requests for arbitration under the Sur de Texas, Villa de Reyes and Tula contracts. CFE requested nullification of clauses that govern the parties' responsibilities in instances of force majeure and requested reimbursement of certain fixed capacity payments. Regarding Sur de Texas, the parties successfully executed an amending agreement as described below and CFE has withdrawn its Sur de Texas arbitration request.

Negotiations continue with respect to the Villa de Reyes and Tula arbitrations with the expectation of reaching agreements before the end of 2019. Accordingly, these arbitration proceedings have been temporarily suspended while negotiations continue.

Sur de Texas

In September 2019, the Sur de Texas pipeline began commercial operations following execution of the above amending agreement with CFE. The original Sur de Texas agreement had a fluctuating toll profile over a 25-year contract term. As a result of the amendment, the contract has been extended and CFE will now receive transportation services for 35 years under a levelized toll structure based on actual construction costs with an initial fixed toll applicable for the first 25 years of the contract term and a higher fixed toll over the last 10 years of the contract. All other terms and conditions of the contract remain substantially unchanged. Monthly revenue for this pipeline will be recognized at a levelized average rate over the 35-year contract term.

Villa de Reyes

Construction of the Villa de Reyes project is ongoing, however the project has experienced force majeure events that have delayed the schedule. We anticipate a phased in-service to commence in early 2020 and have received certain capacity payments under force majeure provisions in the contract, but have not commenced recording revenues.

Tula

Construction on the central segment of the Tula project has been delayed due to a lack of progress by the Secretary of Energy, the governmental department responsible for Indigenous consultations. The project in-service date is estimated to be two years after the Secretary of Energy successfully concludes such consultations. We have received certain capacity payments under force majeure provisions in the contract, but have not commenced recording revenues.

LIQUIDS PIPELINES

Keystone Pipeline System

In January 2019, we entered into an agreement with Motiva Enterprises LLC (Motiva) to construct a pipeline connection between the Keystone Pipeline system and Motiva's 630,000 Bbl/d refinery in Port Arthur, Texas. The connection is targeted to be operational in second quarter 2020.

In early February 2019, the Keystone Pipeline system was temporarily shut down after a leak was detected near St. Charles, Missouri. The pipeline system was restarted the same day while the segment between Steele City, Nebraska to Patoka, Illinois was restarted in mid-February 2019. This shutdown is not expected to have a significant impact on our 2019 earnings.

Keystone XL

In March 2019, U.S. President Trump issued a new Presidential Permit for the Keystone XL project which superseded the 2017 Permit and resulted in the dismissal of the cases related to the 2017 Permit and injunction barring certain pre-construction activities and construction of the project by the U.S. Court of Appeals (Appellate Court) for the Ninth Circuit.

On June 27, 2019, the U.S. Government and TC Energy filed motions to dismiss the lawsuit brought by two U.S. Native American communities that have been expanded to challenge both the 2017 and 2019 Presidential Permits. The U.S. District Court in Montana heard argument on motions to dismiss the complaints on September 12, 2019 and a decision is expected by year end.

On June 27, 2019, the U.S. Government filed a motion to dismiss the challenge to the 2019 Presidential Permit brought by the Indigenous Environmental Network. TC Energy has intervened and moved to dismiss this lawsuit. A hearing on the motion to dismiss and a motion for a preliminary injunction by the Indigenous Environmental Network was held by the U.S. District Court in Montana on October 9, 2019. A ruling is expected to be made by year end.

On August 23, 2019, the Nebraska Supreme Court affirmed the November 2017 decision by the Nebraska Public Service Commission that approved the Keystone XL Pipeline route through the state. A motion for re-hearing of the decision has been denied.

The U.S. Department of State issued a Draft Supplemental Environmental Impact Statement (DSEIS) for the project on October 4, 2019. The DSEIS supplements the 2014 Keystone XL SEIS. It considers changes in the project since 2014 including routing in Nebraska and incorporates updated information and new studies. The SEIS is expected to be issued by the end of 2019.

We continue to actively manage legal and regulatory matters as the project advances.

White Spruce

The White Spruce pipeline, which transports crude oil from Canadian Natural Resources Limited's Horizon facility in northeast Alberta to the Grand Rapids pipeline, was placed in service in May 2019.

Northern Courier

On July 17, 2019, we completed the sale of an 85 per cent equity interest in Northern Courier to Alberta Investment Management Corporation for gross proceeds of $144 million before post-closing adjustments, resulting in a pre-tax gain of $69 million after recording our remaining 15 per cent interest at fair value. 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 issued $1.0 billion of long-term, non-recourse debt, the proceeds from which were paid to TC Energy, resulting in aggregate gross proceeds to TC Energy of $1.15 billion from this asset monetization.

We remain the operator of the Northern Courier pipeline and are using the equity method to account for our remaining 15 per cent interest in our Consolidated financial statements.

POWER AND STORAGE (PREVIOUSLY ENERGY)

Ontario natural gas-fired power plants

On July 30, 2019, we entered into an agreement to sell our Halton Hills and Napanee power plants as well as our 50 per cent interest in Portlands Energy Centre to a subsidiary of Ontario Power Generation Inc. 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 reaching commercial operations as outlined in the agreement. We expect this sale to result in a total pre-tax loss of approximately $330 million ($231 million after tax). As these assets have been classified as held for sale, $202 million of this pre-tax loss ($133 million after tax) has been recorded at September 30, 2019. The remaining loss primarily reflects the residual costs to be incurred until Napanee is placed in service, including capitalized interest, and will be recorded on or before closing of the transaction.

In March 2019, Napanee experienced an equipment failure while progressing commissioning activities. Steps are being taken to address the situation and commercial operations are expected to commence in late first quarter 2020 with an estimated project cost of $1.8 billion.

Coolidge Generating Station

In December 2018, we entered into an agreement to sell our 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 we terminated the agreement with SWG. On May 21, 2019, we completed the sale to SRP as per the terms of their ROFR for proceeds of US$448 million before post-closing adjustments, resulting in a pre-tax gain of $68 million ($54 million after tax).

Monetization of U.S. Northeast power business

In May 2019, we sold our remaining U.S. Northeast power marketing contracts. This transaction concludes the wind-down of our U.S. Northeast power marketing business.

Financial condition

We strive to maintain strong financial capacity and flexibility in all parts of the economic cycle. We rely on our operating cash flow to sustain our business, pay dividends and fund a portion of our growth. In addition, we access capital markets and engage in portfolio management to meet our financing needs, manage our capital structure and to preserve our credit ratings.

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

At September 30, 2019, our current assets totaled $8.3 billion and current liabilities amounted to $11.0 billion, leaving us with a working capital deficit of $2.7 billion compared to $7.8 billion at December 31, 2018. Our working capital deficiency is considered to be in the normal course of business and is managed through:

- our ability to generate predictable and growing cash flow from operations
- approximately $11.5 billion of unutilized, unsecured credit facilities
- our access to capital markets.

CASH PROVIDED BY OPERATING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(millions of $, except per share amounts)	**2019**	**2018**	**2019**	**2018**
Net cash provided by operations	**1,585**	1,299	**5,256**	4,516
(Decrease)/increase in operating working capital	**(140)**	284	**(329)**	130
Funds generated from operations	**1,445**	1,583	**4,927**	4,646
Specific items:				
Current income tax expense on sale of Columbia Midstream assets	**357**	—	**357**	—
U.S. Northeast power marketing contracts	**—**	(12)	**8**	(5)
Comparable funds generated from operations	**1,802**	1,571	**5,292**	4,641
Dividends on preferred shares	**(40)**	(40)	**(120)**	(118)
Distributions to non-controlling interests	**(50)**	(57)	**(164)**	(174)
Non-recoverable maintenance capital expenditures[1]	**(55)**	(61)	**(178)**	(191)
Comparable distributable cash flow	**1,657**	1,413	**4,830**	4,158
Comparable distributable cash flow per common share	**$1.78**	$1.56	**$5.21**	$4.63

1 Includes non-recoverable maintenance capital expenditures from all segments including cash contributions to fund our proportionate share of maintenance capital expenditures for our equity investments which are primarily related to contributions to Bruce Power.

COMPARABLE FUNDS GENERATED FROM OPERATIONS

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

Comparable funds generated from operations increased by $231 million and $651 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 primarily due to higher comparable earnings adjusted for non-cash items and the cash impact of specific items.

NET CASH PROVIDED BY OPERATIONS

Net cash provided by operations increased by $286 million and $740 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 primarily due to higher funds generated from operations as well as the amount and timing of working capital changes.

COMPARABLE DISTRIBUTABLE CASH FLOW

Comparable distributable cash flow, a non-GAAP measure, helps us assess the cash available to common shareholders before capital allocation.

Comparable distributable cash flow increased by $244 million and $672 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 and reflects higher comparable funds generated from operations as described above. Comparable distributable cash flow per common share of $1.78 and $5.21 for the three and nine months ended September 30, 2019 also incorporates the dilutive impact of common shares issued under our DRP in 2018 and 2019 and our Corporate ATM program in 2018.

CASH USED IN INVESTING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(millions of $)	**2019**	**2018**	**2019**	**2018**
Capital spending				
Capital expenditures	**(1,818)**	(2,435)	**(5,411)**	(6,474)
Capital projects in development	**(184)**	(127)	**(565)**	(239)
Contributions to equity investments	**(133)**	(236)	**(453)**	(778)
	(2,135)	(2,798)	**(6,429)**	(7,491)
Proceeds from sale of assets, net of transaction costs	**1,807**	—	**2,398**	—
Other distributions from equity investments	**—**	—	**186**	121
Deferred amounts and other	**(73)**	(16)	**(154)**	78
Net cash used in investing activities	**(401)**	(2,814)	**(3,999)**	(7,292)

Capital expenditures in 2019 were incurred primarily for the expansion of the NGTL System and Columbia Gas projects along with construction of the Coastal GasLink pipeline, Napanee power generating facility and maintenance capital expenditures. Lower spending in 2019 reflects Columbia Gas and Columbia Gulf growth projects being completed and placed in service and the approaching completion of Napanee, partially offset by increased spending on the NGTL System and Coastal GasLink.

Costs incurred on capital projects in development in 2019 and 2018 were mostly attributable to spending on Keystone XL.

Contributions to equity investments decreased in 2019 compared to 2018 mainly due to lower contributions to Sur de Texas, which included our proportionate share of debt financing requirements during construction, and lower contributions to Millennium.

In third quarter 2019, we closed the sale of certain of our Columbia Midstream assets for net proceeds of $1.7 billion (US$1.3 billion) and the sale of an 85 per cent equity interest in Northern Courier for net proceeds of $146 million.

In second quarter 2019, we closed the sale of our Coolidge generating station for net proceeds of $591 million.

Other distributions from equity investments reflect our proportionate share of Bruce Power and Northern Border financings undertaken to fund their respective capital programs and to make distributions to their partners. In first quarter 2019, we received distributions of $120 million (2018 – $121 million) from Bruce Power in connection with their issuance of senior notes in capital markets. In second quarter 2019, we received distributions of $66 million (2018 – nil) from Northern Border originating from a draw on its revolving credit facility to manage capitalization levels.

CASH PROVIDED BY FINANCING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(millions of $)	**2019**	**2018**	**2019**	**2018**
Notes payable (repaid)/issued, net	**(2,584)**	1,421	**(688)**	1,906
Long-term debt issued, net of issue costs[1]	**1,994**	1,026	**3,015**	4,359
Long-term debt repaid[1]	**(1)**	(1,232)	**(1,835)**	(3,266)
Junior subordinated notes issued, net of issue costs	**1,441**	—	**1,441**	—
Dividends and distributions paid	**(549)**	(513)	**(1,628)**	(1,446)
Common shares issued, net of issue costs	**83**	354	**242**	1,139
Partnership units of TC PipeLines, LP issued, net of issue costs	**—**	—	**—**	49
Net cash provided by financing activities	**384**	1,056	**547**	2,741

1 Includes draws and repayments on an unsecured loan facility by TC PipeLines, LP.

We maintain access to debt capital markets to partially fund our growth programs and for other financing requirements. In July 2019, Northern Courier issued $1.0 billion of long-term, non-recourse debt, the proceeds of which were paid to TC Energy prior to the sale of an 85 per cent equity interest in the pipeline. Refer to the Recent developments section for additional information.

In September 2019, we issued $1.0 billion of Medium Term Notes. As well, we issued US$1.1 billion of Junior Subordinated Notes through the TransCanada Trust, a wholly-owned financing trust subsidiary of TCPL. Further details related to our long-term debt and junior subordinated notes as at and for the three and nine months ended September 30, 2019 are discussed in Note 8, Long-term debt, and Note 9, Junior subordinated notes of our Condensed consolidated financial statements.

DIVIDEND REINVESTMENT PLAN

With respect to the common share dividend declared on August 1, 2019, the DRP participation rate amongst common shareholders was approximately 35 per cent resulting in $247 million reinvested in common equity under the program. Year-to-date in 2019, the participation rate amongst common shareholders has been approximately 34 per cent resulting in $711 million of dividends reinvested.

Commencing with the dividends declared October 31, 2019, common shares purchased with reinvested cash dividends under TC Energy's DRP will no longer be satisfied with shares issued from treasury at a discount, but rather will be acquired on the open market at 100 per cent of the weighted average purchase price. The DRP is available for dividends payable on TC Energy's common and preferred shares.

DIVIDENDS

On October 31, 2019, we declared quarterly dividends on our common shares of $0.75 per share payable on January 31, 2020 to shareholders of record at the close of business on December 31, 2019.

SHARE INFORMATION

At October 29, 2019, we had 934 million issued and outstanding common shares and 9 million outstanding options to buy common shares, of which 5 million were exercisable.

Shareholders of the Series 9 preferred shares had the option to convert to Series 10 preferred shares by providing notice on or before October 15, 2019. As the total number of Series 9 preferred shares tendered for conversion did not meet the established threshold, no Series 9 preferred shares were subsequently converted into Series 10 preferred shares.

CREDIT FACILITIES

We have several committed credit facilities that support our commercial paper programs and provide short-term liquidity for general corporate purposes. In addition, we have demand credit facilities that are also used for general corporate purposes, including issuing letters of credit and providing additional liquidity.

At October 29, 2019, we had a total of $12.6 billion of committed revolving and demand credit facilities of which $11.4 billion remains available.

At October 29, 2019, our operated affiliates had an additional $0.8 billion of undrawn capacity on committed credit facilities.

Refer to Financial risks and financial instruments for more information about liquidity, market and other risks.

CONTRACTUAL OBLIGATIONS

Our capital expenditure commitments have remained at approximately the same level as on December 31, 2018. Increased commitments related to the construction of Coastal GasLink and Columbia growth projects were offset by the fulfillment of commitments for the NGTL System, White Spruce, Canadian Mainline and Villa de Reyes.

There were no other material changes to our contractual obligations in third quarter 2019 or to payments due in the next five years or after. Refer to the MD&A in our 2018 Annual Report for more information about our contractual obligations.

Financial risks and financial instruments

We are exposed to market risk and counterparty credit risk and have strategies, policies and limits in place to manage the impact of these risks on our earnings, cash flow and, ultimately, shareholder value. Risk management strategies, policies and limits are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance.

Refer to our 2018 Annual Report for more information about the risks we face in our business which have not changed substantially since December 31, 2018.

In May 2019, we sold our remaining U.S. Northeast power marketing contracts. This transaction concludes the wind-down of our U.S. Northeast power marketing business, reducing our commodity price risk.

INTEREST RATE RISK

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

FOREIGN EXCHANGE RISK

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

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

Average exchange rate – U.S. to Canadian dollars

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

three months ended September 30, 2019	**1.32**
three months ended September 30, 2018	1.31
nine months ended September 30, 2019	**1.33**
nine months ended September 30, 2018	1.29

The impact of changes in the value of the U.S. dollar on our U.S. and Mexico operations is partially offset by interest on U.S. dollar-denominated debt as set out in the table below. Comparable EBIT is a non-GAAP measure.

Significant U.S. dollar-denominated amounts

(millions of US$)	three months ended September 30 2019	2018	nine months ended September 30 2019	2018
U.S. Natural Gas Pipelines comparable EBIT	**459**	417	**1,550**	1,348
Mexico Natural Gas Pipelines comparable EBIT[1]	**122**	122	**349**	366
U.S. Liquids Pipelines comparable EBIT	**306**	218	**894**	605
Interest on U.S. dollar-denominated long-term debt and junior subordinated notes	**(330)**	(335)	**(989)**	(981)
Capitalized interest on U.S. dollar-denominated capital expenditures	**9**	4	**24**	10
U.S. dollar-denominated allowance for funds used during construction	**48**	91	**156**	230
U.S. dollar comparable non-controlling interests and other	**(46)**	(50)	**(174)**	(195)
	568	467	**1,810**	1,383

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

Net investment hedges

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

COUNTERPARTY CREDIT RISK

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

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

We monitor counterparties and review our accounts receivable regularly and, if needed, we record allowances for doubtful accounts using the specific identification method. At September 30, 2019, we had no significant credit losses, no significant credit risk concentration and no significant amounts past due or impaired.

Continued low natural gas prices have presented increased financial challenges to certain of our WCSB and Appalachian natural gas pipeline shippers. We do not expect these shipper challenges to result in any material negative impact to our earnings or cash flow.

We have significant credit and performance exposure to financial institutions because they hold cash deposits and provide committed credit lines and letters of credit that help manage our exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

LIQUIDITY RISK

We manage our liquidity risk by continuously forecasting our cash flow and making sure we have adequate cash balances, cash flow from operations, committed and demand credit facilities and access to capital markets to meet our operating, financing and capital expenditure obligations under both normal and stressed economic conditions.

LOAN RECEIVABLE FROM AFFILIATE

We hold a 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline. We account for our interest in the joint venture as an equity investment. In 2017, we 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 September 30, 2019, our Condensed consolidated balance sheet included a MXN$20.9 billion or $1.4 billion (December 31, 2018 – MXN$18.9 billion or $1.3 billion) loan receivable from the Sur de Texas joint venture which represents our proportionate share of long-term debt financing requirements related to the joint venture. Interest income and other included interest income of $38 million and $110 million for the three and nine months ended September 30, 2019 (2018 – $32 million and $88 million) from this joint venture with a corresponding proportionate share of interest expense recorded in Income from equity investments in our Mexico Natural Gas Pipelines segment. As a result, there is no impact to net income.

FINANCIAL INSTRUMENTS

With the exception of Long-term debt and Junior subordinated notes, our derivative and non-derivative financial instruments are recorded on the balance sheet at fair value unless they were entered into and continue to be held for the purpose of receipt or delivery in accordance with our normal purchase and sales exemptions and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain accounting exemptions.

Derivative instruments

We use derivative instruments to reduce volatility associated with fluctuations in commodity prices, interest rates and foreign exchange rates. Derivative instruments, including those that qualify and are designated for hedge accounting treatment, are recorded at fair value.

The majority of derivative instruments that are not designated or do not qualify for hedge accounting treatment have been entered into as economic hedges to manage our exposure to market risk and are classified as held for trading. Changes in the fair value of held-for-trading derivative instruments are recorded in net income in the period of change. This may expose us to increased variability in reported operating results since the fair value of the held-for-trading derivative instruments can fluctuate significantly from period to period.

Balance sheet presentation of derivative instruments

The balance sheet presentation of the fair value of derivative instruments is as follows:

(millions of $)	September 30, 2019	December 31, 2018
Other current assets	**211**	737
Intangible and other assets	**52**	61
Accounts payable and other	**(213)**	(922)
Other long-term liabilities	**(154)**	(42)
	(104)	(166)

Unrealized and realized (losses)/gains on derivative instruments

The following summary does not include hedges of our net investment in foreign operations:

	three months ended September 30		nine months ended September 30	
(millions of $)	2019	2018	2019	2018
Derivative instruments held for trading[1]				
Amount of unrealized (losses)/gains in the period				
Commodities[2]	**(69)**	(31)	**(98)**	(41)
Foreign exchange	**(31)**	60	**176**	(79)
Amount of realized gains/(losses) in the period				
Commodities	**132**	81	**319**	210
Foreign exchange	**(9)**	(5)	**(68)**	14
Derivative instruments in hedging relationships				
Amount of realized gains/(losses) in the period				
Commodities	**1**	1	**(8)**	—
Interest rate	**1**	(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 the three and nine months ended September 30, 2019 and 2018, 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.

Effect of fair value and cash flow hedging relationships

The following tables detail amounts presented in the Condensed consolidated statement of income and in which accounts the effects of fair value or cash flow hedging relationships are recorded:

	three months ended September 30			
	Revenues (Power and Storage)		Interest Expense	
(millions of $)	2019	2018	2019	2018
Total Amount Presented in the Condensed Consolidated Statement of Income	**96**	535	**(573)**	(577)
Fair Value Hedges				
Interest rate contracts				
Hedged items	**—**	—	**(5)**	(17)
Derivatives designated as hedging instruments	**—**	—	**1**	(2)
Cash Flow Hedges				
Reclassification of losses on derivative instruments from AOCI to net income[1,2]				
Interest rate contracts	**—**	—	**(1)**	(5)
Commodity contracts	**(4)**	(3)	**—**	—

1 Refer to our Condensed consolidated financial statements for the components of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests.

2 There are no amounts recognized in earnings that were excluded from effectiveness testing.

	nine months ended September 30			
	Revenues (Power and Storage)		Interest Expense	
(millions of $)	2019	2018	2019	2018
Total Amount Presented in the Condensed Consolidated Statement of Income	**674**	1,724	**(1,747)**	(1,662)
Fair Value Hedges				
Interest rate contracts				
Hedged items	**—**	—	**(16)**	(59)
Derivatives designated as hedging instruments	**—**	—	**—**	(4)
Cash Flow Hedges				
Reclassification of losses on derivative instruments from AOCI to net income[1,2]				
Interest rate contracts	**—**	—	**(9)**	(17)
Commodity contracts	**(4)**	(4)	**—**	—

1 Refer to our Condensed consolidated financial statements for the components of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests.

2 There are no amounts recognized in earnings that were excluded from effectiveness testing.

Credit-risk-related contingent features of derivative instruments

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

Based on contracts in place and market prices at September 30, 2019, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $5 million (December 31, 2018 – $6 million), with no collateral provided in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on September 30, 2019, we would have been required to provide collateral of $5 million (December 31, 2018 – $6 million) to our counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

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

Other information

CONTROLS AND PROCEDURES

Management, including our President and CEO and our CFO, evaluated the effectiveness of our disclosure controls and procedures as at September 30, 2019, as required by the Canadian securities regulatory authorities and by the SEC, and concluded that our disclosure controls and procedures are effective at a reasonable assurance level.

There were no changes in third quarter 2019 that had or are likely to have a material impact on our internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES AND ACCOUNTING POLICY CHANGES

When we prepare financial statements that conform with U.S. GAAP, we are required to make estimates and assumptions that affect the timing and amounts we record for our assets, liabilities, revenues and expenses because these items may be affected by future events. We base the estimates and assumptions on the most current information available, using our best judgement. We also regularly assess the assets and liabilities themselves. A summary of our critical accounting estimates is included in our 2018 Annual Report.

Our significant accounting policies have remained unchanged since December 31, 2018 other than described below. A summary of our significant accounting policies is included in our 2018 Annual Report.

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 twelve 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 us to not apply the new guidance, including disclosure requirements, to the comparative periods presented.

We elected available practical expedients and exemptions upon adoption which allowed us:

- 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 our 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 we are the lessee and for facility and liquids tank terminals for which we are the lessor
- to use hindsight in determining the lease term and assessing ROU assets for impairment.

The new guidance had a significant impact on our Condensed consolidated balance sheet, but did not have an impact on our Condensed consolidated statements of income and cash flows. The most significant impact was the recognition of ROU assets and lease liabilities for operating leases and providing significant new disclosures about our leasing activities. Refer to our Condensed consolidated financial statements for further information related to the impact of adopting the new guidance and our updated accounting policies related to leases.

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 our leases includes the noncancellable period of the lease plus any additional periods covered by either our option to extend (or not to terminate) the lease that we are 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.

Fair value measurement

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

Implementation costs of cloud computing arrangements

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

Consolidation

In October 2018, the FASB issued new guidance for determining whether fees paid to decision makers and service providers are variable interests for indirect interests held through related parties under common control. This new guidance is effective January 1, 2020 and will be applied on a retrospective basis, however, early adoption is permitted. We do not expect the adoption of this new guidance to have a material impact on our 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 January 1, 2021 and will be applied on a retrospective basis, however, early adoption is permitted. We are currently evaluating the timing and impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

	2019			2018				2017
(millions of $, except per share amounts)	**Third**	**Second**	**First**	**Fourth**	**Third**	**Second**	**First**	**Fourth**
Revenues	**3,133**	3,372	3,487	3,904	3,156	3,195	3,424	3,617
Net income attributable to common shares	**739**	1,125	1,004	1,092	928	785	734	861
Comparable earnings	**970**	924	987	946	902	768	864	719
Share statistics								
Net income per common share – basic and diluted	**$0.79**	$1.21	$1.09	$1.19	$1.02	$0.88	$0.83	$0.98
Comparable earnings per common share	**$1.04**	$1.00	$1.07	$1.03	$1.00	$0.86	$0.98	$0.82
Dividends declared per common share	**$0.75**	$0.75	$0.75	$0.69	$0.69	$0.69	$0.69	$0.625

FACTORS AFFECTING QUARTERLY FINANCIAL INFORMATION BY BUSINESS SEGMENT

Quarter-over-quarter revenues and net income fluctuate for reasons that vary across our business segments.

In our Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Mexico Natural Gas Pipelines segments, except for seasonal fluctuations in short-term throughput volumes on U.S. pipelines, quarter-over-quarter revenues and net income generally remain relatively stable during any fiscal year. Over the long term, however, they fluctuate because of:

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

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

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

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

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

FACTORS AFFECTING FINANCIAL INFORMATION BY QUARTER

We calculate comparable measures by adjusting certain GAAP and non-GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period.

Comparable earnings exclude the unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives generally provide effective economic hedges, but do not meet the criteria for hedge accounting. As a result, the changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them part of our underlying operations.

In third quarter 2019, comparable earnings also excluded:

- an after-tax loss of $133 million at September 30, 2019 related to the Ontario natural gas-fired power plants held for sale. The total after-tax loss on this sale is expected to be $231 million. The remaining loss primarily reflects the residual costs to be incurred until Napanee is placed in service, including capitalized interest, and will be recorded on or before closing which is anticipated by the end of first quarter 2020
- an after-tax loss of $133 million related to the sale of certain Columbia Midstream assets in August 2019
- an after-tax gain of $115 million related to the partial sale of Northern Courier in July 2019.

In second quarter 2019, comparable earnings also excluded:

- an after-tax gain of $54 million related to the sale of our Coolidge generating station
- a deferred tax benefit of $32 million related to the impact of an Alberta corporate income tax rate reduction on our Canadian businesses not subject to rate-regulated accounting
- an after-tax gain of $6 million related to the remainder of our U.S. Northeast power marketing contracts which were sold in May 2019.

In first quarter 2019, comparable earnings also excluded:

- an after-tax loss of $12 million related to our U.S. Northeast power marketing contracts.

In fourth quarter 2018, comparable earnings also excluded:

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

In third quarter 2018, comparable earnings also excluded:

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

In second quarter 2018, comparable earnings also excluded:

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

In the first quarter 2018, comparable earnings also excluded:

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

In fourth quarter 2017, comparable earnings also excluded:

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