

# Quarterly report to shareholders

## Third quarter 2017

### Financial highlights

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
<b>Income</b>				
Revenues	<b>3,242</b>	3,632	<b>9,850</b>	8,886
Net income/(loss) attributable to controlling interests and to common shares	<b>636</b>	(118)	<b>2,217</b>	655
Comparable EBITDA <sup>1</sup>	<b>1,667</b>	1,886	<b>5,474</b>	4,757
Comparable earnings <sup>1</sup>	<b>638</b>	639	<b>2,052</b>	1,552
<b>Cash flows</b>				
Net cash provided by operations	<b>1,168</b>	1,305	<b>3,789</b>	3,590
Comparable funds generated from operations <sup>1</sup>	<b>1,296</b>	1,430	<b>4,139</b>	3,739
Comparable distributable cash flow <sup>1</sup>	<b>788</b>	1,011	<b>2,936</b>	2,680
Capital spending - capital expenditures	<b>2,031</b>	1,444	<b>5,383</b>	3,262
- projects in development	<b>37</b>	62	<b>135</b>	219
- contributions to equity investments	<b>475</b>	286	<b>1,140</b>	570
Acquisitions, net of cash acquired	—	12,609	—	13,608
Proceeds from sales of assets, net of transaction costs	—	—	<b>4,147</b>	6
<b>Basic common shares outstanding (millions)</b>				
Average for the period	<b>867</b>	823	<b>864</b>	790
End of period	<b>868</b>	823	<b>868</b>	823

<sup>1</sup> Comparable EBITDA, comparable earnings, comparable funds generated from operations and comparable distributable cash flow are all non-GAAP measures. See the non-GAAP measures section for more information.

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## Management's discussion and analysis

November 8, 2017

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TransCanada Pipelines Limited (TCPL). It discusses our business, operations, financial position, risks and other factors for the three and nine months ended September 30, 2017, and should be read with the accompanying unaudited condensed consolidated financial statements for the three and nine months ended September 30, 2017 which have been prepared in accordance with U.S. GAAP.

This MD&A should also be read in conjunction with our December 31, 2016 audited consolidated financial statements and notes and the MD&A in our 2016 Annual Report.

### 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. These statements generally include words like *anticipate, expect, believe, may, will, should, estimate* or other similar words.

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

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

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

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

#### Assumptions

- inflation rates, commodity prices and capacity prices
- nature and scope of hedging
- regulatory decisions and outcomes
- foreign exchange rates
- interest rates
- tax rates

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- planned and unplanned outages and the use of our pipeline and energy assets
- integrity and reliability of our assets
- access to capital markets
- anticipated construction costs, schedules and completion dates.

### **Risks and uncertainties**

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

You can read more about these factors and others in reports we have filed with Canadian securities regulators and the SEC, including the MD&A in our 2016 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 TCPL in our Annual Information Form and other disclosure documents, which are available on SEDAR ([www.sedar.com](http://www.sedar.com)).

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**NON-GAAP MEASURES**

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

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

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

**Comparable measures**

We calculate comparable measures by adjusting certain GAAP and non-GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period. 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 to adjust for a specific item is subjective and made after careful consideration. Specific items may include:

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

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

The following table identifies our non-GAAP measures against their equivalent GAAP measures.

<b>Comparable measure</b>	<b>Original measure</b>
comparable earnings	net income attributable to common shares
comparable EBITDA	segmented earnings
comparable EBIT	segmented earnings
comparable funds generated from operations	net cash provided by operations
comparable distributable cash flow	net cash provided by operations

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### **Comparable earnings**

Comparable earnings represent earnings or loss attributable to controlling interests and to common shareholders on a consolidated basis, adjusted for specific items. Comparable earnings is comprised of segmented earnings, interest expense, AFUDC, interest income and other, income taxes and non-controlling interests, adjusted for the specific items. See the Consolidated results section for a reconciliation to net income attributable to controlling interests and to common shares.

### **Comparable EBIT and comparable EBITDA**

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

### **Funds generated from operations and comparable funds generated from operations**

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

### **Comparable distributable cash flow**

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 distributions to non-controlling interests and maintenance capital expenditures. Maintenance capital expenditures are expenditures incurred to maintain our operating capacity, asset integrity and reliability, and include amounts attributable to our proportionate share of maintenance capital expenditures on our equity investments. Although we deduct maintenance capital expenditures in determining comparable distributable cash flow, in certain of our rate-regulated businesses, maintenance capital expenditures are included in their respective rate bases, on which we earn a regulated return and recover depreciation through future tolls. See the Financial condition section for a reconciliation to net cash provided by operations.

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## Consolidated results - third quarter 2017

Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 results have been adjusted to reflect this change.

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
Canadian Natural Gas Pipelines	316	329	903	943
U.S. Natural Gas Pipelines	337	332	1,299	787
Mexico Natural Gas Pipelines	95	98	333	184
Liquids Pipelines	203	183	681	593
Energy	237	(828)	1,080	(583)
Corporate	(29)	(36)	(102)	(87)
<b>Total segmented earnings</b>	<b>1,159</b>	<b>78</b>	<b>4,194</b>	<b>1,837</b>
Interest expense	(522)	(538)	(1,578)	(1,369)
Allowance for funds used during construction	145	110	367	322
Interest income and other	83	18	192	128
<b>Income/(loss) before income taxes</b>	<b>865</b>	<b>(332)</b>	<b>3,175</b>	<b>918</b>
Income tax (expense)/recovery	(185)	266	(769)	(79)
<b>Net income/(loss)</b>	<b>680</b>	<b>(66)</b>	<b>2,406</b>	<b>839</b>
Net income attributable to non-controlling interests	(44)	(52)	(189)	(184)
<b>Net income/(loss) attributable to controlling interests and to common shares</b>	<b>636</b>	<b>(118)</b>	<b>2,217</b>	<b>655</b>

Net income attributable to controlling interests and to common shares increased by \$754 million and \$1,562 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016.

The 2017 results included:

- a \$243 million after-tax net gain related to the monetization of our U.S. Northeast power business, which included a \$440 million after-tax gain on the sale of TC Hydro, an incremental loss of \$183 million after tax recorded on the sale of the thermal and wind package and \$14 million year-to-date of after-tax disposition costs and income tax adjustments
- an after-tax charge of \$30 million in third quarter and \$69 million year-to-date for integration-related costs associated with the acquisition of Columbia
- an after-tax charge of \$8 million in third quarter and \$19 million year-to-date related to the maintenance of Keystone XL assets which is being expensed pending further advancement of the project
- a \$7 million income tax recovery in first quarter related to the realized loss on a third party sale of Keystone XL project assets. A provision for the expected pre-tax loss on these assets was included in our 2015 impairment charge, but the related income tax recoveries could not be recorded until realized.

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The 2016 results included:

- a \$656 million after-tax impairment on Ravenswood goodwill. As a result of information received during the process to monetize our U.S. Northeast Power business in third quarter 2016, it was determined that the fair value of Ravenswood no longer exceeded its carrying value
- a \$176 million after-tax impairment charge in first quarter on the carrying value of our Alberta PPAs as a result of our decision to terminate the PPAs
- costs associated with the acquisition of Columbia including an after-tax charge of \$67 million in third quarter, primarily relating to retention, severance and integration expenses, and \$103 million year-to-date which included \$36 million related to acquisition costs
- \$28 million of income tax recoveries in third quarter related to the realized loss on a third party sale of Keystone XL project assets. A provision for the expected loss on these assets was included in our fourth quarter 2015 impairment charge, but the related income tax recoveries could not be recorded until realized
- an after-tax charge of \$9 million in third quarter and \$24 million year-to-date related to Keystone XL costs for the maintenance and liquidation of project assets which are expensed pending further advancement of the project
- an after-tax charge of \$10 million year-to-date for restructuring charges mainly related to expected future losses under lease commitments. These charges formed part of a restructuring initiative, which commenced in 2015, to maximize the effectiveness and efficiency of our existing operations and reduce overall costs
- \$3 million of after-tax costs related to the monetization of our U.S. Northeast Power business
- an additional \$3 million after-tax loss on the sale of TC Offshore which closed on March 31, 2016.

Net income in all periods included unrealized gains and losses from changes in risk management activities which we exclude, along with the above-noted items, to arrive at comparable earnings.

Comparable earnings decreased by \$1 million and increased by \$500 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016 as discussed below in the reconciliation of net income to comparable earnings.

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**RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS**

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
<b>Net income/(loss) attributable to controlling interests and to common shares</b>	<b>636</b>	(118)	<b>2,217</b>	655
<b>Specific items (net of tax):</b>				
Net loss/(gain) on sales of U.S. Northeast power assets	<b>12</b>	3	<b>(243)</b>	3
Integration and acquisition related costs – Columbia	<b>30</b>	67	<b>69</b>	103
Keystone XL asset costs	<b>8</b>	9	<b>19</b>	24
Keystone XL income tax recoveries	—	(28)	<b>(7)</b>	(28)
Ravenswood goodwill impairment	—	656	—	656
Alberta PPA terminations	—	—	—	176
Restructuring costs	—	—	—	10
TC Offshore loss on sale	—	—	—	3
Risk management activities <sup>1</sup>	<b>(48)</b>	50	<b>(3)</b>	(50)
<b>Comparable earnings</b>	<b>638</b>	639	<b>2,052</b>	1,552

<sup>1</sup> Risk management activities (unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
Canadian Power	<b>1</b>	(4)	<b>5</b>	3
U.S. Power	<b>59</b>	(73)	<b>(97)</b>	16
Liquids marketing	<b>(19)</b>	(8)	<b>(15)</b>	(6)
Natural Gas Storage	<b>4</b>	4	<b>5</b>	9
Interest rate	<b>(1)</b>	—	<b>(1)</b>	—
Foreign exchange	<b>33</b>	—	<b>89</b>	49
Income tax attributable to risk management activities	<b>(29)</b>	31	<b>17</b>	(21)
<b>Total unrealized gains/(losses) from risk management activities</b>	<b>48</b>	(50)	<b>3</b>	50



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Comparable earnings decreased by \$1 million for the three months ended September 30, 2017 compared to the same period in 2016. This decrease was primarily the net effect of:

- lower contribution from U.S. Power due to the monetization of our U.S. Northeast power generation assets in second quarter 2017
- lower contribution from U.S. Natural Gas Pipelines primarily due to the timing of funding contributions to the Columbia Gas defined benefit pension plan, partially offset by higher ANR transportation revenues resulting from a FERC-approved rate settlement effective August 1, 2016
- higher AFUDC on our rate-regulated U.S. natural gas pipelines
- lower interest expense mainly due to the repayment of the remaining bridge facilities that partially funded the acquisition of Columbia
- higher interest income and other primarily due to realized gains in 2017 compared to realized losses in 2016 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and income recognized on the termination of the PRGT project
- higher contribution from Liquids Pipelines primarily due to higher volumes on Keystone and the commencement of operations on Grand Rapids
- higher earnings from Bruce Power mainly due to improved results from contracting activities
- higher contribution from Mexico Natural Gas Pipelines primarily due to earnings from Mazatlán beginning in December 2016, partially offset by the impairment of our equity investment in TransGas.

Comparable earnings increased by \$500 million for the nine months ended September 30, 2017 compared to the same period in 2016. This increase was primarily the net effect of:

- higher contribution from U.S. Natural Gas Pipelines due to incremental earnings resulting from the Columbia acquisition on July 1, 2016, higher ANR transportation revenues resulting from a FERC-approved rate settlement effective August 1, 2016, partially offset by the timing of funding contributions to the Columbia Gas defined benefit pension plan
- increased earnings from Bruce Power mainly due to higher volumes resulting from fewer planned outage days
- higher contribution from Mexico Natural Gas Pipelines due to earnings from Topolobampo beginning in July 2016 and Mazatlán beginning in December 2016, partially offset by the impairment of our equity investment in TransGas
- higher earnings from Liquids Pipelines primarily due to higher volumes on Keystone and the commencement of operations on Grand Rapids
- higher AFUDC on our rate-regulated U.S. natural gas pipelines, as well as the NGTL System, partially offset by the commercial in-service of Topolobampo and completion of Mazatlán construction
- higher interest income and other due to income related to Coastal GasLink project costs and the termination of the PRGT project
- higher earnings from Western Power following the termination of the Alberta PPAs in March 2016
- lower contribution from U.S. Power due to the monetization of our U.S. Northeast power generation assets in second quarter 2017
- higher interest expense as a result of debt assumed in the acquisition of Columbia on July 1, 2016, and long-term debt and junior subordinated note issuances.

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## 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 \$24 billion of near-term projects and approximately \$24 billion of medium to longer-term projects. Amounts presented exclude maintenance capital expenditures, capitalized interest and AFUDC. All projects are subject to cost adjustments due to market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits.

### Near-term projects

<b>at September 30, 2017</b>			
(unaudited - billions of \$)	<b>Expected in-service date</b>	<b>Estimated project cost</b>	<b>Carrying value</b>
<b>Canadian Natural Gas Pipelines</b>			
Canadian Mainline	2017-2019	0.5	0.2
NGTL System <sup>1</sup>	2017	2.3	1.5
	2018	0.3	0.1
	2019	2.2	0.3
	2020	1.9	0.1
	2021+	0.4	—
<b>U.S. Natural Gas Pipelines</b>			
Columbia Gas			
Leach XPress	2018	US 1.6	US 1.3
Modernization I	2017	US 0.2	US 0.2
WB XPress	2018	US 0.8	US 0.3
Mountaineer XPress	2018	US 2.6	US 0.4
Modernization II	2018-2020	US 1.1	US 0.1
Columbia Gulf			
Rayne XPress	2017	US 0.4	US 0.4
Cameron Access	2018	US 0.3	US 0.2
Gulf XPress	2018	US 0.6	US 0.2
Midstream – Gibraltar	2017	US 0.3	US 0.2
<b>Mexico Natural Gas Pipelines</b>			
Tula	2018	US 0.6	US 0.5
Villa de Reyes	2018	US 0.6	US 0.4
Sur de Texas <sup>2</sup>	2018	US 1.3	US 0.7
<b>Liquids Pipelines</b>			
Northern Courier	2017	1.0	1.0
White Spruce	2018	0.2	—
<b>Energy</b>			
Napanee	2018	1.1	0.9
Bruce Power – life extension <sup>3</sup>	up to 2020+	1.0	0.2
		<b>21.3</b>	<b>9.2</b>
Foreign exchange impact on near-term projects <sup>4</sup>		<b>2.6</b>	<b>1.2</b>
<b>Total near-term projects (billions of Cdn\$)</b>		<b>23.9</b>	<b>10.4</b>

<sup>1</sup> Beginning in second quarter 2017, near-term NGTL System capital projects are being reported by expected in-service dates.

<sup>2</sup> Our proportionate share.

<sup>3</sup> Amounts reflect our proportionate share of the remaining capital costs that Bruce Power expects to incur on its life extension investment programs in advance of major refurbishment outages which are expected to begin in 2020.

<sup>4</sup> Reflects U.S./Canada foreign exchange rate of 1.25 at September 30, 2017.

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### Medium to longer-term projects

The medium to longer-term projects have greater uncertainty with respect to timing and estimated project costs. The expected in-service dates of these projects are post-2020, and costs provided in the schedule below reflect the most recent costs for each project as filed with the various regulatory authorities or otherwise determined. These projects have all been commercially secured or, in the case of Keystone XL, commercial support is expected to be achieved. All these projects are subject to approvals that include FID and/or complex regulatory processes.

<b>at September 30, 2017</b>			
(unaudited - billions of \$)	Segment	Estimated project cost	Carrying value
Heartland and TC Terminals	Liquids Pipelines	0.9	0.1
Grand Rapids Phase 2 <sup>1</sup>	Liquids Pipelines	0.7	—
Bruce Power – life extension <sup>1</sup>	Energy	5.3	—
<b>Keystone projects</b>			
Keystone XL <sup>2</sup>	Liquids Pipelines	US 8.0	US 0.3
Keystone Hardisty Terminal <sup>2</sup>	Liquids Pipelines	0.3	0.1
<b>BC west coast LNG-related projects</b>			
Coastal GasLink	Canadian Natural Gas Pipelines	4.8	0.4
NGTL System – Merrick	Canadian Natural Gas Pipelines	1.9	—
		21.9	0.9
Foreign exchange impact on medium to longer-term projects <sup>3</sup>		2.0	0.1
<b>Total medium to longer-term projects (billions of Cdn\$)</b>		<b>23.9</b>	<b>1.0</b>

<sup>1</sup> Our proportionate share.

<sup>2</sup> Carrying value reflects amount remaining after impairment charge recorded in fourth quarter 2015.

<sup>3</sup> Reflects U.S./Canada foreign exchange rate of 1.25 at September 30, 2017.

## Outlook

Our overall comparable earnings outlook for 2017 is expected to be higher than what was previously included in the 2016 Annual Report as a result of stronger performance across our business segments as reported in our 2017 year-to-date results in this MD&A.

### Consolidated capital spending

Our expected total capital expenditures, projects in development and contributions to equity investments for 2017 as outlined in the 2016 Annual Report remains unchanged.

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## Canadian Natural Gas Pipelines

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

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
NGTL System	256	246	722	713
Canadian Mainline	263	278	774	800
Other Canadian pipelines <sup>1</sup>	25	27	81	89
Business development	—	(2)	(2)	(4)
<b>Comparable EBITDA</b>	<b>544</b>	<b>549</b>	<b>1,575</b>	<b>1,598</b>
Depreciation and amortization	(228)	(220)	(672)	(655)
<b>Comparable EBIT and segmented earnings</b>	<b>316</b>	<b>329</b>	<b>903</b>	<b>943</b>

<sup>1</sup> Includes results from Foothills, Ventures LP and our share of equity income from our investment in TQM.

Canadian Natural Gas Pipelines segmented earnings decreased by \$13 million and \$40 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016 and are equivalent to comparable EBIT.

Net income and comparable EBITDA for our rate-regulated Canadian Natural Gas Pipelines are generally affected by our approved ROE, our investment base, our level of deemed common equity and incentive earnings or losses. 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 revenues on a flow-through basis.

### NET INCOME - NGTL SYSTEM AND CANADIAN MAINLINE

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
NGTL System	92	81	261	233
Canadian Mainline	49	52	149	154

Net income for the NGTL System increased by \$11 million and \$28 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016 mainly due to a higher average investment base and higher OM&A incentive earnings, partially offset by higher carrying charges on regulatory deferrals in 2017. The NGTL System is operating under the two-year 2016-2017 Revenue Requirement Settlement which includes an ROE of 10.1 per cent on 40 per cent deemed equity and a mechanism for sharing variances above and below a fixed annual OM&A amount with flow-through treatment of all other costs.

Net income for the Canadian Mainline decreased by \$3 million for the three months ended September 30, 2017 compared to the same period in 2016 primarily due to a lower average investment base and lower incentive earnings. Net income decreased by \$5 million for the nine months ended September 30, 2017 compared to the same period in 2016 primarily due to a lower average investment base and higher carrying charges on regulatory deferrals, partially offset by higher incentive earnings. The Canadian Mainline is operating under the NEB 2014 Decision which includes an approved ROE of 10.1 per cent on a 40 per cent deemed equity with a possible range of achieved outcomes between 8.7 per cent and 11.5 per cent. The decision also includes an incentive mechanism that has both upside and downside risk and a \$20 million annual after-tax contribution from TCPL.

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**DEPRECIATION AND AMORTIZATION**

Depreciation and amortization increased by \$8 million and \$17 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016 mainly due to facilities that were placed in service for the NGTL System and Canadian Mainline.

**OPERATING STATISTICS - NGTL SYSTEM AND CANADIAN MAINLINE**

<b>nine months ended September 30</b> (unaudited)	<b>NGTL System<sup>1</sup></b>		<b>Canadian Mainline<sup>2</sup></b>	
	<b>2017</b>	<b>2016</b>	<b>2017</b>	<b>2016</b>
Average investment base (millions of \$)	<b>8,210</b>	7,401	<b>4,165</b>	4,423
Delivery volumes (Bcf):				
Total	<b>3,015</b>	2,978	<b>1,244</b>	1,217
Average per day	<b>11.0</b>	10.9	<b>4.6</b>	4.4

<sup>1</sup> Field receipt volumes for the NGTL System for the nine months ended September 30, 2017 were 3,111 Bcf (2016 – 3,080 Bcf). Average per day was 11.4 Bcf (2016 – 11.2 Bcf).

<sup>2</sup> Canadian Mainline's throughput volumes represent physical deliveries to domestic and export markets. Physical receipts originating at the Alberta border and in Saskatchewan for the nine months ended September 30, 2017 were 716 Bcf (2016 – 802 Bcf). Average per day was 2.6 Bcf (2016 – 2.9 Bcf).

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## U.S. Natural Gas Pipelines

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

(unaudited - millions of US\$, unless otherwise noted)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
Columbia Gas <sup>1</sup>	125	123	446	123
ANR	86	76	301	233
TC PipeLines, LP <sup>2,3</sup>	25	32	83	90
Great Lakes <sup>4</sup>	9	11	49	48
Midstream <sup>1</sup>	27	26	70	26
Columbia Gulf <sup>1</sup>	16	11	55	11
Other U.S. pipelines <sup>1,2,3,5</sup>	23	22	78	46
Non-controlling interests <sup>6</sup>	74	94	257	264
Business development	—	(1)	(1)	(2)
<b>Comparable EBITDA</b>	<b>385</b>	394	<b>1,338</b>	839
Depreciation and amortization	(116)	(104)	(340)	(204)
<b>Comparable EBIT</b>	<b>269</b>	290	<b>998</b>	635
Foreign exchange impact	68	94	311	208
<b>Comparable EBIT (Cdn\$)</b>	<b>337</b>	384	<b>1,309</b>	843
Specific items:				
Integration and acquisition related costs – Columbia	—	(52)	(10)	(52)
TC Offshore loss on sale	—	—	—	(4)
<b>Segmented earnings (Cdn\$)</b>	<b>337</b>	332	<b>1,299</b>	787

<sup>1</sup> We completed the acquisition of Columbia on July 1, 2016 and the publicly held units of Columbia Pipeline Partners LP (CPPL) on February 17, 2017.

<sup>2</sup> Results from Northern Border and Iroquois reflect our share of equity income from these investments. We acquired additional interests in Iroquois of 0.65 per cent on May 1, 2016 and 4.87 per cent on March 31, 2016. TC PipeLines, LP acquired TCPL's 49.34 per cent interest in Iroquois and its remaining 11.81 per cent interest in PNGTS on June 1, 2017.

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

	Effective ownership percentage as of	
	September 30, 2017	September 30, 2016
TC PipeLines, LP	26.0	27.1
Effective ownership through TC PipeLines, LP:		
Great Lakes	12.1	12.6
PNGTS	16.1	13.5

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

<sup>5</sup> Includes our effective ownership in Millennium and Hardy Storage and our direct ownership in Iroquois and PNGTS up to June 1, 2017.

<sup>6</sup> Comparable EBITDA for the portions of TC PipeLines, LP, PNGTS and CPPL that we do not own. Effective February 17, 2017, we acquired the remaining publicly held units of CPPL.

## THIRD QUARTER 2017

U.S. Natural Gas Pipelines segmented earnings increased by \$5 million and \$512 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016 primarily due to the acquisition of Columbia.

Segmented earnings for the nine months ended September 30, 2017 included a first quarter \$10 million pre-tax charge primarily due to integration-related costs associated with the Columbia acquisition. Segmented earnings for the nine months ended September 30, 2016 included a \$52 million pre-tax charge primarily due to integration and acquisition-related costs associated with the Columbia acquisition and a \$4 million pre-tax loss as a result of a December 2015 agreement to sell TC Offshore which closed in early 2016. These amounts have been excluded from our calculation of comparable EBIT. As well, a weaker U.S. dollar had a negative impact on the Canadian dollar equivalent segmented earnings from our U.S. operations.

Earnings from our U.S. Natural Gas Pipelines operations, which include Columbia effective July 1, 2016, are generally affected by contracted volume levels, volumes delivered and the rates charged as well as by the cost of providing services. Columbia and ANR results are also affected by the contracting and pricing of their storage capacity and commodity sales. Transmission and storage revenues are generally higher in winter months due to increased seasonal demand for our services.

Comparable EBITDA for U.S. Natural Gas Pipelines decreased by US\$9 million for the three months ended September 30, 2017 compared to the same period in 2016. This was primarily the net effect of:

- the timing of funding contributions to the Columbia Gas defined benefit pension plan. Under the current rate settlement for Columbia Gas, pension costs are reflected in expense as funding occurs and the full 2017 pension funding for this plan was recorded in third quarter 2017
- increased revenue from Columbia Gas growth projects
- higher ANR transportation and storage revenue resulting from a FERC-approved rate settlement effective August 1, 2016.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US\$499 million for the nine months ended September 30, 2017 compared to the same period in 2016. This was primarily the net effect of:

- the earnings contribution resulting from the Columbia acquisition for nine months in 2017 compared to only three months in 2016
- higher ANR transportation and storage revenue resulting from a FERC-approved rate settlement effective August 1, 2016.

## **DEPRECIATION AND AMORTIZATION**

Depreciation and amortization increased by US\$12 million and US\$136 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016 mainly due to the acquisition of Columbia and higher depreciation rates on ANR following the FERC-approved rate settlement effective August 1, 2016.

US\$5 million of first quarter 2017 depreciation related to Columbia information system assets retired as part of the Columbia integration process has been excluded from comparable EBIT and included as part of integration and acquisition related costs to arrive at segmented earnings.

THIRD QUARTER 2017

## Mexico Natural Gas Pipelines

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

(unaudited - millions of US\$, unless otherwise noted)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
Topolobampo	39	41	119	40
Tamazunchale	29	24	85	79
Guadalajara	17	17	51	49
Mazatlán	16	—	49	—
Sur de Texas <sup>1</sup>	3	—	14	—
Other <sup>2</sup>	(10)	—	(10)	—
Business development	—	1	—	(4)
<b>Comparable EBITDA</b>	<b>94</b>	<b>83</b>	<b>308</b>	<b>164</b>
Depreciation and amortization	(18)	(10)	(54)	(23)
<b>Comparable EBIT</b>	<b>76</b>	<b>73</b>	<b>254</b>	<b>141</b>
Foreign exchange impact	19	25	79	43
<b>Comparable EBIT and segmented earnings (Cdn\$)</b>	<b>95</b>	<b>98</b>	<b>333</b>	<b>184</b>

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

<sup>2</sup> Reflects results from our 46.5 per cent equity investment in TransGas. On August 25, 2017, TransGas transferred all of its pipeline assets to Transportadora de Gas Internacional S.A..

Mexico Natural Gas Pipelines segmented earnings decreased by \$3 million and increased \$149 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016 and are equivalent to comparable EBIT. Aside from commercial factors outlined below, a weaker U.S. dollar had a negative impact on the Canadian dollar equivalent segmented earnings from our Mexico operations.

Earnings from our Mexico operations are underpinned by long-term, stable, primarily U.S. dollar-denominated revenue contracts, and are affected by the cost of providing service.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US\$11 million and US\$144 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016 and was the net effect of:

- incremental earnings from Topolobampo on a year-to-date basis. The Topolobampo project has experienced a delay in construction which, under the terms of our Transportation Service Agreement (TSA) with the CFE, constitutes a force majeure event with provisions allowing for the collection and recognition of revenue as per the original TSA service commencement date of July 2016
- incremental earnings from Mazatlán. Construction is complete and the collection and recognition of revenue began as per the terms of the TSA in December 2016
- equity earnings from our investment in the Sur de Texas pipeline which records AFUDC during construction, net of interest expense on an inter-affiliate loan from TCPL
- the impairment of our equity investment in TransGas. See Recent developments section for further detail.

### DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US\$8 million and US\$31 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016 primarily due to the commencement of depreciation on Topolobampo and Mazatlán.



THIRD QUARTER 2017

## Liquids Pipelines

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

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
Keystone Pipeline System	302	280	937	856
Business development and other	1	(2)	10	(6)
<b>Comparable EBITDA</b>	<b>303</b>	278	<b>947</b>	850
Depreciation and amortization	(71)	(73)	(228)	(214)
<b>Comparable EBIT</b>	<b>232</b>	205	<b>719</b>	636
Specific items:				
Keystone XL asset costs	(10)	(14)	(23)	(37)
Risk management activities	(19)	(8)	(15)	(6)
<b>Segmented earnings</b>	<b>203</b>	183	<b>681</b>	593
<b>Comparable EBIT denominated as follows:</b>				
Canadian dollars	63	51	175	160
U.S. dollars	135	117	416	360
Foreign exchange impact	34	37	128	116
	<b>232</b>	205	<b>719</b>	636

Liquids Pipelines segmented earnings increased by \$20 million and \$88 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016 and included pre-tax charges related to Keystone XL costs for the maintenance of project assets which are being expensed pending further advancement of the project as well as unrealized losses from changes in the fair value of derivatives related to our liquids marketing business.

Keystone Pipeline System earnings are generated primarily by providing pipeline capacity to shippers for fixed monthly payments that are not linked to actual throughput volumes. Uncontracted capacity is offered to the market on a spot basis and provides opportunities to generate incremental earnings.

Comparable EBITDA for Liquids Pipelines increased by \$25 million and \$97 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016 and was the net effect of:

- higher volumes on Keystone pipeline
- higher contribution from liquids marketing activities
- contribution from Grand Rapids pipeline, which was placed in service in late-August 2017
- increased business development activities, including advancement of Keystone XL
- a weaker U.S. dollar which had a negative impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

### DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by \$14 million for the nine months ended September 30, 2017 compared to the same period in 2016 as a result of the timing of new facilities being placed in service, partially offset by the effect of a weaker U.S. dollar.

THIRD QUARTER 2017

## Energy

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

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
<b>Canadian Power</b>				
Western Power <sup>1</sup>	24	26	77	48
Eastern Power	75	81	252	267
Bruce Power	91	76	314	210
<b>Canadian Power - comparable EBITDA<sup>1,2</sup></b>	<b>190</b>	183	<b>643</b>	525
Depreciation and amortization	(35)	(36)	(108)	(119)
<b>Canadian Power - comparable EBIT<sup>1,2</sup></b>	<b>155</b>	147	<b>535</b>	406
<b>U.S. Power (US\$)</b>				
<b>U.S. Power - comparable EBITDA<sup>3</sup></b>	<b>22</b>	164	<b>108</b>	321
Depreciation and amortization <sup>4</sup>	—	(34)	—	(98)
<b>U.S. Power - comparable EBIT</b>	<b>22</b>	130	<b>108</b>	223
Foreign exchange impact	7	44	34	72
<b>U.S. Power - comparable EBIT (Cdn\$)</b>	<b>29</b>	174	<b>142</b>	295
<b>Natural Gas Storage and other - comparable EBITDA</b>	<b>8</b>	20	<b>40</b>	38
Depreciation and amortization	(4)	(3)	(10)	(9)
<b>Natural Gas Storage and other - comparable EBIT</b>	<b>4</b>	17	<b>30</b>	29
<b>Business Development comparable EBITDA and EBIT</b>	<b>(3)</b>	(3)	<b>(9)</b>	(11)
<b>Energy - comparable EBIT<sup>1,2,3</sup></b>	<b>185</b>	335	<b>698</b>	719
Specific items:				
Net (loss)/gain on sales of U.S. Northeast power assets	(12)	(5)	469	(5)
Ravenswood goodwill impairment	—	(1,085)	—	(1,085)
Alberta PPA terminations	—	—	—	(240)
Risk management activities	64	(73)	(87)	28
<b>Segmented earnings/(losses)<sup>1,2,3</sup></b>	<b>237</b>	(828)	<b>1,080</b>	(583)

<sup>1</sup> Included losses from the Alberta PPAs up to March 7, 2016 when the PPAs were terminated.

<sup>2</sup> Includes our share of equity income from our investments in Portlands Energy and Bruce Power.

<sup>3</sup> TC Hydro earnings included up to April 19, 2017 sale date; Ravenswood, Ironwood, Ocean State Power and Kibby Wind earnings included up to June 2, 2017 sale date.

<sup>4</sup> Depreciation of U.S. Northeast power assets ceased effective November 2016 when classified as held for sale.

## THIRD QUARTER 2017

Energy segmented earnings increased by \$1,065 million and \$1,663 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016 and included the following specific items:

- in 2017, a net gain of \$469 million before tax related to the monetization of our U.S. Northeast power business which included a \$715 million gain on the sale of TC Hydro, a loss of \$226 million on the sale of the thermal and wind package and \$20 million (2016 - \$5 million) of pre-tax disposition costs. See Recent developments section for more details
- in 2016, a \$1,085 million pre-tax impairment charge on the Ravenswood goodwill. As a result of information received during the process to monetize our U.S. Northeast Power business, it was determined that the fair value of Ravenswood no longer exceeded its carrying value
- in 2016, a \$240 million pre-tax charge, which included a \$29 million impairment of our equity investment in ASTC Power Partnership, on the carrying value of our Alberta PPAs as a result of our decision to terminate the PPAs
- unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks as follows:

Risk management activities (unaudited - millions of \$, pre-tax)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
Canadian Power	1	(4)	5	3
U.S. Power	59	(73)	(97)	16
Natural Gas Storage	4	4	5	9
<b>Total unrealized gains/(losses) from risk management activities</b>	<b>64</b>	<b>(73)</b>	<b>(87)</b>	<b>28</b>

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

The remainder of the Energy segmented earnings are equivalent to comparable EBIT and are discussed in the following sections.

THIRD QUARTER 2017

**CANADIAN POWER****Western and Eastern Power**

The following are the components of comparable EBITDA and comparable EBIT.

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
<b>Revenues<sup>1</sup></b>				
Western Power	39	43	128	167
Eastern Power	103	112	301	315
Other <sup>2</sup>	4	2	24	31
	<b>146</b>	157	<b>453</b>	513
Income from equity investments	8	9	23	16
Commodity purchases resold	—	(1)	(2)	(60)
Plant operating costs and other	(55)	(58)	(145)	(154)
<b>Comparable EBITDA<sup>3</sup></b>	<b>99</b>	107	<b>329</b>	315
Depreciation and amortization	(35)	(36)	(108)	(119)
<b>Comparable EBIT<sup>3</sup></b>	<b>64</b>	71	<b>221</b>	196
<b>Breakdown of comparable EBITDA</b>				
Western Power <sup>3</sup>	24	26	77	48
Eastern Power	75	81	252	267
<b>Comparable EBITDA<sup>3</sup></b>	<b>99</b>	107	<b>329</b>	315
<b>Plant availability<sup>4</sup></b>				
Western Power	94%	94%	96%	92%
Eastern Power	97%	96%	96%	93%

<sup>1</sup> Includes the realized gains and losses from financial derivatives used to manage Canadian Power's assets which are presented on a net basis in Western and Eastern Power revenues. The unrealized gains and losses from financial derivatives have been excluded to arrive at comparable EBITDA.

<sup>2</sup> Includes revenues from the sale of unused natural gas transportation and sale of excess natural gas purchased for generation.

<sup>3</sup> Included Alberta PPAs up to March 7, 2016 when the PPAs were terminated.

<sup>4</sup> The percentage of time the plant was available to generate power, regardless of whether it was running.

**Western Power**

Comparable EBITDA for Western Power increased by \$29 million for the nine months ended September 30, 2017 compared to the same period in 2016. Results from the Alberta PPAs are included up to March 7, 2016 when we terminated the PPAs for the Sundance A, Sundance B and Sheerness facilities.

**Eastern Power**

Comparable EBITDA for Eastern Power decreased by \$6 million and \$15 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016 mainly due to lower earnings from our renewable assets and from the Ontario gas-fired plants due to reduced ancillary revenue opportunities. Lower earnings from the sale of unused natural gas transportation also contributed to the decreased earnings for the nine months ended September 30, 2017 compared to the same period in 2016.

**DEPRECIATION AND AMORTIZATION**

Depreciation and amortization decreased by \$11 million for the nine months ended September 30, 2017 compared to the same period in 2016 following the termination of the Alberta PPAs.

THIRD QUARTER 2017

**Bruce Power**

Bruce Power results reflect our proportionate share. The following is our proportionate share of the components of comparable EBITDA and comparable EBIT.

(unaudited - millions of \$, unless noted otherwise)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
Equity income included in comparable EBITDA and EBIT comprised of:				
Revenues	<b>383</b>	369	<b>1,212</b>	1,109
Operating expenses	<b>(205)</b>	(208)	<b>(638)</b>	(658)
Depreciation and other	<b>(87)</b>	(85)	<b>(260)</b>	(241)
<b>Comparable EBITDA and EBIT<sup>1</sup></b>	<b>91</b>	76	<b>314</b>	210
<b>Bruce Power – other information</b>				
Plant availability <sup>2</sup>	<b>86%</b>	88%	<b>89%</b>	82%
Planned outage days	<b>81</b>	50	<b>178</b>	335
Unplanned outage days	<b>19</b>	37	<b>39</b>	49
Sales volumes (GWh) <sup>1</sup>	<b>5,801</b>	5,886	<b>18,093</b>	16,420
Realized sales price per MWh <sup>3</sup>	<b>\$67</b>	\$67	<b>\$67</b>	\$67

<sup>1</sup> Represents our 48.4 per cent (2016 - 48.5 per cent) ownership interest in Bruce Power. Sales volumes include deemed generation.

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

<sup>3</sup> Calculation based on actual and deemed generation. Realized sales prices 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.

Comparable EBITDA from Bruce Power increased by \$15 million for the three months ended September 30, 2017 compared to the same period in 2016 due to improved results from contracting activities partially offset by lower volumes resulting from increased planned outage days.

Comparable EBITDA from Bruce Power increased by \$104 million for the nine months ended September 30, 2017 compared to the same period in 2016 due to higher volumes resulting from fewer planned outage days and higher gains from contracting activities, partially offset by higher interest expense.

Planned outage work, which commenced on Unit 3 in August 2017, was completed in September 2017. Planned maintenance on Unit 6 began in September 2017 and is scheduled to be completed in fourth quarter 2017. The overall average plant availability percentage in 2017 is expected to be approximately 90 per cent.

**U.S. POWER**

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

**NATURAL GAS STORAGE AND OTHER**

Comparable EBITDA for Natural Gas Storage and other decreased by \$12 million for the three months ended September 30, 2017 compared to the same period in 2016 mainly due to lower realized natural gas storage price spreads.

THIRD QUARTER 2017

## Corporate

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

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
Comparable EBITDA and EBIT	(4)	8	(20)	7
Specific items:				
Integration and acquisition related costs – Columbia	(32)	(44)	(81)	(80)
Foreign exchange gain/(loss) – inter-affiliate loan <sup>1</sup>	7	—	(1)	—
Restructuring costs	—	—	—	(14)
Segmented losses	(29)	(36)	(102)	(87)

<sup>1</sup> Reported in Income from equity investments on the condensed consolidated statement of income.

Corporate segmented losses decreased by \$7 million for the three months ended September 30, 2017, and increased by \$15 million for the nine months ended September 30, 2017 compared to the same periods in 2016 and included the following specific items that have been excluded from comparable EBIT:

- integration and acquisition costs associated with the acquisition of Columbia
- foreign exchange on an inter-affiliate loan, which is offset in Interest income and other. This peso-denominated loan to the Sur de Texas project represents our proportionate share of its financing
- in 2016, restructuring costs related to expected future losses under lease commitments.

Comparable EBITDA decreased by \$12 million and \$27 million for the three and nine months ended September 30, 2017, respectively, compared to the same periods in 2016 primarily due to increased legal and other general and administrative costs recorded in 2017.

## OTHER INCOME STATEMENT ITEMS

### Interest expense

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
<b>Interest on long-term debt and junior subordinated notes</b>				
Canadian dollar-denominated	(130)	(122)	(356)	(343)
U.S. dollar-denominated	(314)	(315)	(954)	(811)
Foreign exchange impact	(79)	(102)	(293)	(260)
	(523)	(539)	(1,603)	(1,414)
Other interest and amortization expense	(47)	(39)	(124)	(82)
Capitalized interest	49	46	150	133
<b>Interest expense included in comparable earnings</b>	<b>(521)</b>	<b>(532)</b>	<b>(1,577)</b>	<b>(1,363)</b>
Specific items:				
Integration and acquisition related costs – Columbia	—	(6)	—	(6)
Risk management activities	(1)	—	(1)	—
<b>Interest expense</b>	<b>(522)</b>	<b>(538)</b>	<b>(1,578)</b>	<b>(1,369)</b>

## THIRD QUARTER 2017

Interest expense decreased by \$16 million in the three months ended September 30, 2017 compared to the same period in 2016 and primarily reflects the net effect of:

- final repayment of the Columbia acquisition bridge facilities in June 2017
- long-term debt and junior subordinated notes issuances, net of maturities
- the impact of a weaker U.S. dollar in translating U.S. dollar denominated interest.

Interest expense increased by \$209 million for the nine months ended September 30, 2017 compared to the same period in 2016 and primarily reflects the net effect of:

- long-term debt and junior subordinated notes issuances, partially offset by Canadian and U.S. dollar-denominated debt maturities
- debt assumed in the acquisition of Columbia on July 1, 2016
- higher capitalized interest on the Napanee power generating facility and LNG projects
- higher related-party debt financing
- the impact of a weaker U.S. dollar in translating U.S. dollar denominated interest.

### Allowance for funds used during construction

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
Canadian dollar-denominated	44	44	149	133
U.S. dollar-denominated	81	55	168	149
Foreign exchange impact	20	11	50	40
<b>Allowance for funds used during construction</b>	<b>145</b>	<b>110</b>	<b>367</b>	<b>322</b>

AFUDC increased by \$35 million and \$45 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016. The year-to-date increase in Canadian dollar-denominated AFUDC is primarily due to continued investment in our NGTL System expansions. The increase in U.S. dollar-denominated AFUDC for both the three and nine months ended September 30, 2017 is primarily due to continued investment and higher rates on projects acquired as part of the Columbia acquisition on July 1, 2016, as well as additional investment in Mexico projects, partially offset by the commercial in-service of Topolobampo and completion of Mazatlán construction.

### Interest income and other

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
<b>Interest income and other included in comparable earnings</b>	<b>57</b>	<b>18</b>	<b>102</b>	<b>79</b>
Specific items:				
Foreign exchange (loss)/gain – inter-affiliate loan	(7)	—	1	—
Risk management activities	33	—	89	49
<b>Interest income and other</b>	<b>83</b>	<b>18</b>	<b>192</b>	<b>128</b>

Interest income and other increased by \$65 million for the three months ended September 30, 2017 compared to the same period in 2016 and was primarily the net effect of:

- realized gains in 2017 compared to losses in 2016 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- \$10 million of income recognized on the termination of the PRGT project, mainly related to the recovery of carrying costs. See Recent developments section for more information

## THIRD QUARTER 2017

- interest income and foreign exchange impact related to an inter-affiliate loan receivable from the Sur de Texas joint venture. The foreign exchange impact is offset in Corporate segmented losses and is excluded from comparable earnings
- higher unrealized gains on risk management activities in 2017 compared to 2016. These amounts have been excluded from comparable earnings.

Interest income and other increased by \$64 million for the nine months ended September 30, 2017 compared to the same period in 2016 and was primarily the net effect of:

- income of \$20 million related to Coastal GasLink project costs incurred to date and \$10 million recognized on the termination of the PRGT project, mainly related to the recovery of carrying costs. See Recent developments section for more information
- lower realized gains in 2017 compared to 2016 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- foreign exchange impact on the translation of foreign currency denominated working capital balances
- interest income and foreign exchange impact related to an inter-affiliate loan receivable from the Sur de Texas joint venture. The foreign exchange impact is offset in Corporate segmented losses and is excluded from comparable earnings
- higher unrealized gains on risk management activities in 2017 compared to 2016. These amounts have been excluded from comparable earnings.

### Income tax expense

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
<b>Income tax expense included in comparable earnings</b>	<b>(160)</b>	(261)	<b>(593)</b>	(631)
Specific items:				
Ravenswood goodwill impairment	—	429	—	429
Sales of U.S. Northeast power assets	—	2	<b>(226)</b>	2
Integration and acquisition related costs – Columbia	<b>2</b>	32	<b>22</b>	32
Keystone XL asset costs	<b>2</b>	5	<b>4</b>	13
Keystone XL income tax recoveries	—	28	<b>7</b>	28
Alberta PPA terminations	—	—	—	64
Restructuring costs	—	—	—	4
TC Offshore loss on sale	—	—	—	1
Risk management activities	<b>(29)</b>	31	<b>17</b>	(21)
<b>Income tax (expense)/recovery</b>	<b>(185)</b>	266	<b>(769)</b>	(79)

Income tax expense included in comparable earnings decreased by \$101 million for the three months ended September 30, 2017 compared to the same periods in 2016 mainly as a result of lower comparable pre-tax earnings in 2017 compared to 2016 and changes in the proportion of income earned between Canadian and foreign jurisdictions.

Income tax expense included in comparable earnings decreased by \$38 million for the nine months ended September 30, 2017 compared to the same period in 2016 mainly as a result of changes in the proportion of income earned between Canadian and foreign jurisdictions and lower flow-through taxes in 2017 on Canadian rate-regulated pipelines, partially offset by higher pre-tax earnings in 2017 compared to 2016.



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**Net income attributable to non-controlling interests**

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
<b>Net income attributable to non-controlling interests included in comparable earnings</b>	<b>(44)</b>	(55)	<b>(189)</b>	(187)
Specific items:				
Acquisition related costs – Columbia	—	3	—	3
<b>Net income attributable to non-controlling interests</b>	<b>(44)</b>	(52)	<b>(189)</b>	(184)

Net income attributable to non-controlling interests decreased by \$8 million and increased by \$5 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016 primarily due to the acquisition of Columbia in July 2016 which included a non-controlling interest in CPPL. In February 2017, we acquired all of the outstanding publicly held common units of CPPL.

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## Recent developments

### CANADIAN NATURAL GAS PIPELINES

#### **NGTL System**

In June 2017, we announced an additional \$2 billion expansion program on our NGTL System based on new contracted customer demand for approximately 3.2 PJ/d (3.0 Bcf/d) of incremental firm receipt and delivery services. We also successfully concluded an expansion open season for incremental service at the Alberta/British Columbia export delivery point, which connects Canadian supply through our downstream pipelines to Pacific Northwest, California and Nevada markets. The open season was over-subscribed and all 408 TJ/d (381 MMcf/d) of available expansion service was awarded under long-term contracts.

The additional expansion program increased our overall near-term capital program on the NGTL System to \$7.1 billion, with completion to 2021.

#### **Towerbirch Expansion**

In March 2017, the Government of Canada approved the \$0.4 billion Towerbirch Expansion project included in the \$7.1 billion expansion of the NGTL System noted above. The project consists of 55 km (34 miles) of 36-inch loop to the Groundbirch Mainline plus 32 km (20 miles) of new 30-inch pipe and four new meter stations. This project was placed in service on November 1, 2017.

#### **North Montney**

In March 2017, we filed an application with the NEB for a variance to the existing approvals for the North Montney project on the NGTL System to remove the condition that the project could only proceed once a positive FID is made for the Pacific Northwest LNG project. North Montney is now underpinned by restructured, 20-year commercial contracts with shippers and is not dependent on the LNG project proceeding. On April 19, 2017, the NEB granted an interim extension to March 31, 2018 of the sunset clause that was due to expire June 10, 2017. In-service dates are planned for April 2019 and April 2020, subject to regulatory approval.

On September 7, 2017, the NEB provided notice that a public hearing process would be used to consider our variance application. The NEB also stated it would consider the continued appropriateness and applicability of the tolling decisions and associated conditions of the original approval. On October 26, 2017, the NEB issued the Hearing Order indicating the oral portion of the hearing will begin the week of January 22, 2018 with a decision to follow within 12 weeks after the hearing conclusion.

#### **NGTL 2018 Revenue Requirement**

NGTL's current two-year settlement, which established revenue requirements for the system, expires on December 31, 2017. NGTL is negotiating with its shippers for its revenue requirements for 2018 and potentially beyond. On October 31, 2017, we filed an application with the NEB for interim tolls effective January 1, 2018.

#### **Canadian Mainline**

##### **Dawn Long-Term Fixed Price Service (LTFP)**

In March 2017, we announced the successful conclusion of the long-term fixed-price open season on the Canadian Mainline for service from the Empress receipt point in Alberta to the Dawn hub in Southern Ontario. The open season resulted in binding, long-term contracts from WCSB gas producers to transport 1.5 PJ/d (1.4 Bcf/d) of natural gas at a simplified toll of \$0.77/GJ. The term of each contract is 10 years and includes early termination rights that can be exercised following the initial five years of service and upon payment of an increased toll for the final two years of the contract. The application to the NEB for approval of the service was filed on April 26, 2017.

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On September 21, 2017, the NEB approved this application, as filed, with an effective date of November 1, 2017. This new service provides our customers with toll certainty and improved market access enabling them to compete effectively with emerging supplies of natural gas from the Marcellus and Utica basins.

### **Canadian Mainline 2018 - 2020 Toll Review**

The Canadian Mainline is required to file for approval of 2018-2020 tolls by December 31, 2017. Tolls were previously established for 2015 to 2017 in accordance with the terms of the 2015-2030 LDC Settlement. While the settlement specified tolls for the 2015 to 2020 period, the NEB ordered a toll review halfway through this six-year period. The review must include costs, forecast volumes, contracting levels, the deferral account balance, and any other material changes.

### **Maple Compressor Expansion Project**

The Canadian Mainline has received requests for expansion capacity to the southern Ontario market plus delivery to Atlantic Canada via the TQM and PNGTS systems. The requests for approximately 86 TJ/d (80 MMcf/d) of firm service underpin the need for new compression at the existing Maple compressor site. Customers have executed 15-year precedent agreements to proceed with the project which has a revised estimated cost of \$110 million. An application to the NEB for approval to proceed with the project is planned for fourth quarter 2017 to meet a November 1, 2019 in-service date.

### **Coastal GasLink**

The continuing delay in the FID for the LNG Canada project triggered a restructuring of provisions in the Coastal GasLink project agreement with LNG Canada that results in the payment of certain amounts to TCPL with respect to carrying charges on costs incurred. In September 2017, an approximate \$80 million payment was received related to costs incurred since inception of the project, and quarterly payments of approximately \$7 million will be received until further notice. We continue to work with LNG Canada under the agreement towards a FID.

### **Prince Rupert Gas Transmission**

In July 2017, we were notified that PNW LNG would not be proceeding with their proposed LNG project and that Progress Energy (Progress) would be terminating their agreement with us for development of the PRGT project, effective August 10, 2017. In accordance with the terms of the agreement, all project costs incurred to advance the project, including carrying charges, are fully recoverable upon termination. As a result, we received a payment of \$0.6 billion from Progress in October 2017.

## **U.S. NATURAL GAS PIPELINES**

### **Leach XPress Project**

The Leach XPress project is expected to have a US\$100 million increase in its capital project cost due to delays caused by weather on the project's construction schedule and the resulting increase in contractor costs. Leach XPress is expected to be placed in service in early-January 2018.

### **Rayne XPress Project**

Rayne Xpress was placed in service November 2, 2017. This Columbia Gulf project will transport approximately 1.1 PJ/d (1.0 Bcf/d) of supply from an interconnect with the Leach XPress pipeline project, and another interconnect, to markets along the system and to the Gulf Coast.

### **Mountaineer XPress Project**

The Mountaineer XPress project is expected to have a US\$600 million increase in its capital project cost due to increased construction cost estimates. As a result of a cost sharing mechanism, overall project returns are not anticipated to be materially affected. Mountaineer XPress is expected to be placed in service in fourth quarter 2018.

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### **Midstream - Gibraltar Pipeline Project**

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

### **Buckeye XPress Project**

The Buckeye XPress project (BXP) represents an upsizing of an existing pipeline replacement project under our Columbia Gas modernization program. The US\$0.2 billion cost to upsize the replacement pipe and install compressor upgrades will enable us to offer 290 TJ/d (275 MMcf/d) of incremental pipeline capacity to accommodate growing Appalachian production. We expect BXP to be placed in service in late 2020.

### **Portland XPress Project**

PNGTS has executed Precedent Agreements with several LDCs in New England and Atlantic Canada to re-contract certain system capacity set to expire in 2019, as well as expand the PNGTS system to bring its certificated capacity up to 280 TJ/d (265 MMcf/d). The approximately US\$80 million Portland XPress Project (PXP) will proceed concurrently with upstream capacity expansions. The in-service dates of PXP are being phased-in over a three year period beginning November 1, 2018.

### **FERC Update**

The FERC regained a quorum of three commissioners in August 2017 and two additional commissioners were approved by the U.S. Senate on November 2, 2017. The FERC has stated that it intends to expeditiously address the resulting backlog of pending applications. We expect the FERC certificates for the WB XPress, Mountaineer XPress and Gulf XPress projects to be received in fourth quarter 2017.

### **Great Lakes**

#### **Rate Case**

On October 30, 2017, Great Lakes filed a rate settlement with the FERC to satisfy its obligations from its 2013 rate settlement for new rates to be in effect by January 1, 2018. The 2017 Great Lakes Settlement, if approved by the FERC, will decrease Great Lakes' maximum transportation rates by 27 per cent beginning October 1, 2017. Great Lakes expects that the impact from other changes, including the recent long-term transportation contract with the Canadian Mainline as described below, other revenue opportunities on the system and the elimination of the revenue sharing mechanism with its customers, will more than offset the full year impact of the reduction in Great Lakes' rates beginning in 2018. The 2017 Great Lakes Settlement does not contain any moratorium and Great Lakes will be required to file for new rates no later than March 31, 2022, with new rates to be effective October 1, 2022.

#### **Impact of Dawn LTFP**

In conjunction with the Canadian Mainline's LTFP service, Great Lakes entered into a new 10-year gas transportation contract with the Canadian Mainline. This contract received NEB approval in September 2017 and became effective on November 1, 2017. This contract contains volume reduction options up to full contract quantity beginning in year three.

#### **Northern Border Settlement**

Northern Border and its shippers have been engaged in settlement discussions and have recently agreed to a settlement-in-principle addressing all rate and service related issues raised during the settlement discussions. Northern Border plans to file a settlement agreement with the FERC before the end of the year, reflecting the settlement-in-principle, precluding the need to file a general rate case as contemplated by its 2012 settlement. Northern Border anticipates that the FERC will accept the settlement agreement and that it will be unopposed. This will provide Northern Border with rate stability over the longer term. At this time, we do not believe that the final outcome of the settlement will have a material impact on our consolidated results. We have a 13 per cent indirect ownership interest in Northern Border through TC PipeLines, LP.

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**Sale of Iroquois and PNGTS to TC PipeLines, LP**

In June 2017, we closed the sale of a 49.34 per cent interest in Iroquois Gas Transmission System, LP and our remaining 11.81 per cent interest in PNGTS to TC PipeLines, LP valued at US\$765 million. Proceeds were comprised of US\$597 million in cash and US\$168 million representing a proportionate share of Iroquois and PNGTS debt.

**Columbia Pipeline Partners LP**

In February 2017, we completed the acquisition, for cash, of all outstanding publicly held common units of CPPL at a price of US\$17.00 and a stub period distribution payment of US\$0.10 per common unit for an aggregate transaction value of US\$921 million.

**MEXICO NATURAL GAS PIPELINES****TransGas**

In third quarter 2017, we recognized an impairment charge of \$12 million on our 46.5 per cent equity investment in TransGas de Occidente S.A. (TransGas). TransGas constructed and operated a natural gas pipeline in Colombia for a 20-year contract term. As per the terms of the agreement, upon completion of the 20-year contract in August 2017, TransGas transferred its pipeline assets to Transportadora de Gas Internacional S.A.. The impairment charge represents the write-down of the remaining carrying value of our equity investment.

**LIQUIDS PIPELINES****Energy East and Related Projects**

On September 7, 2017, we requested the NEB suspend the review of the Energy East and Eastern Mainline project applications for 30 days to provide time for us to conduct a careful review of the NEB's changes, announced on August 23, 2017, regarding the list of issues and environmental assessment factors related to the projects and how these changes impact the projects' costs, schedules and viability.

On October 5, 2017, after careful review of the changed circumstances, we informed the NEB that we will not be proceeding with the Energy East and Eastern Mainline project applications. We have also notified Québec's Ministère du Développement durable, de l'Environnement, et de la Lutte contre les changements climatiques that we are withdrawing the Energy East project from the environmental review process. As the Energy East pipeline was also to provide transportation services for the Upland pipeline, the U.S. Department of State was notified on October 5, 2017, that we will no longer be pursuing the U.S. Presidential Permit application for that project.

We are reviewing the approximate \$1.3 billion carrying value of the projects, including AFUDC capitalized since inception, and expect an estimated \$1 billion after-tax non-cash charge will be recorded in our fourth quarter 2017 results. We ceased capitalizing AFUDC on the projects effective August 23, 2017, the date of the NEB's announced scope changes. With Energy East's inability to reach a regulatory decision, no recoveries of costs from third parties are expected.

**Keystone XL**

In March 2017, the U.S. Department of State issued a U.S. Presidential Permit authorizing construction of the U.S./Canada border crossing facilities of the Keystone XL pipeline. We discontinued our claim under Chapter 11 of the North American Free Trade Agreement and have also withdrawn the U.S. Constitutional challenge. With the receipt of the U.S. Presidential Permit, we will continue to work through the Nebraska PSC process to obtain route approval through that state and with other U.S. federal agencies to obtain ancillary permits.

Given the passage of time since the Keystone XL Presidential Permit application was previously denied in November 2015, we are updating the shipping contracts and anticipate the core contract shipper group will be modified with the introduction of new shippers and reductions in volume commitments by other shippers. We anticipate commercial

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support for the project to be substantially similar to that which existed when we first applied for a Keystone XL pipeline permit.

In July 2017, we launched an open season to solicit additional binding commitments from interested parties for transportation of crude oil on the Keystone Pipeline and for the Keystone XL pipeline project from Hardisty, Alberta to markets in Cushing, Oklahoma and the U.S. Gulf Coast. On September 6, 2017, we extended this open season to October 26, 2017 due to the impact caused by Hurricane Harvey to Houston, Texas and parts of the U.S. Gulf Coast. We are currently analyzing the results of the open season.

In February 2017, we filed an application with the Nebraska Public Service Commission (PSC) seeking approval for the Keystone XL pipeline route through that state. In August 2017, the Nebraska PSC concluded the public hearing for the Keystone XL pipeline and final written submissions were submitted in September 2017. The Nebraska PSC will review all comments gathered from the public meetings, the written submissions and the hearing before making a final decision on the route permit which is expected by the end of November 2017.

### **Grand Rapids**

In late August 2017, the Grand Rapids pipeline, jointly owned by TCPL and PetroChina Canada Ltd. (formerly Brion Energy Corporation) was placed in service. The 460 km (287 mile) crude oil transportation system plays a key role in connecting producing areas northwest of Fort McMurray, Alberta, to terminals in the Edmonton/Heartland region.

### **Northern Courier**

Northern Courier, a 90 km (56 mile) pipeline which transports bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta, achieved commercial in-service on November 1, 2017.

## **ENERGY**

### **U.S. Power**

#### **Monetization of U.S. Northeast power business**

In April 2017, we closed the sale of TC Hydro to Great River Hydro, LLC for US\$1.07 billion resulting in a gain of \$715 million (\$440 million after tax) recorded in 2017.

In June 2017, we closed the sale of Ravenswood, Ironwood, Ocean State Power and Kibby Wind to Helix Generation, LLC for US\$2.029 billion. An additional loss on sale of approximately \$226 million (\$183 million after tax) was recorded in 2017, primarily related to an adjustment to the purchase price and repair costs for an unplanned outage at Ravenswood prior to close. Insurance recoveries for a portion of the repair costs are expected to be received by the end of 2017 and will partially reduce this loss.

Proceeds from the sale transactions were used to fully retire the remaining bridge facilities that partially funded the acquisition of Columbia.

After assessing our options, we initiated the wind down of our U.S. power marketing operations and will realize the value of the remaining marketing contracts and working capital over time.

### **Ontario Solar**

On October 24, 2017, we entered into an agreement to sell our Ontario Solar portfolio, comprised of eight facilities with a total generating capacity of 76 MWs, to Axiom Infinity Solar LP for approximately \$540 million. The sale is expected to close by the end of 2017, subject to certain regulatory and other approvals, and will include customary closing adjustments. The transaction is expected to result in an estimated gain of \$130 million before tax (\$100 million after tax) to be recognized upon closing.

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## Financial condition

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

We believe we have the financial capacity to fund our existing capital program through our predictable and growing cash flow from operations, access to capital markets, portfolio management including proceeds from potential drop downs of additional natural gas pipeline assets to TC PipeLines, LP, cash on hand and substantial committed credit facilities.

At September 30, 2017, our current assets were \$5.8 billion and current liabilities were \$13.7 billion, leaving us with a working capital deficit of \$7.9 billion compared to a deficit of \$2.0 billion at December 31, 2016. Our working capital deficiency is considered to be in the normal course of business and is managed through:

- our ability to generate cash flow from operations
- our access to capital markets
- our access to inter-affiliate lending
- approximately \$9.1 billion of unutilized, unsecured credit facilities.

### CASH PROVIDED BY OPERATING ACTIVITIES

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
Net cash provided by operations	1,168	1,305	3,789	3,590
Increase/(decrease) in operating working capital	83	7	223	(28)
Funds generated from operations <sup>1</sup>	1,251	1,312	4,012	3,562
Specific items:				
Integration and acquisition related costs – Columbia	32	99	84	135
Keystone XL asset costs	10	14	23	37
U.S. Northeast power disposition costs	3	5	20	5
<b>Comparable funds generated from operations<sup>1</sup></b>	<b>1,296</b>	<b>1,430</b>	<b>4,139</b>	<b>3,739</b>
Distributions paid to non-controlling interests	(66)	(77)	(215)	(201)
Maintenance capital expenditures including equity investments	(442)	(342)	(988)	(858)
<b>Comparable distributable cash flow<sup>1</sup></b>	<b>788</b>	<b>1,011</b>	<b>2,936</b>	<b>2,680</b>

<sup>1</sup> See the non-GAAP measures section in this MD&A for further discussion of funds generated from operations, comparable funds generated from operations and comparable distributable cash flow.

### COMPARABLE FUNDS GENERATED FROM OPERATIONS

Comparable funds generated from operations, a non-GAAP measure, decreased \$134 million for the three months ended September 30, 2017 compared to the same period in 2016 primarily due to lower comparable EBITDA (excluding income from equity investments) and increased funding of our U.S. employee post-retirement benefit plans, partially offset by higher distributions from our equity investments and interest income and other.

Comparable funds generated from operations increased \$400 million for the nine months ended September 30, 2017 compared to the same period in 2016 primarily due to higher comparable EBITDA (excluding income from equity investments) and higher distributions from our equity investments, partially offset by higher interest expense and increased funding of our employee post-retirement benefit plans.

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**COMPARABLE DISTRIBUTABLE CASH FLOW**

Comparable distributable cash flow, a non-GAAP measure, helps us assess the cash available to common shareholders before capital allocation. The decrease for the three months ended September 30, 2017 compared to the same period in 2016 was primarily driven by the decrease in comparable funds generated from operations and higher maintenance capital expenditures. The increase on a year-to-date basis is primarily due to the increase in comparable funds generated from operations, partially offset by higher maintenance capital expenditures.

Although we deduct maintenance capital expenditures in determining comparable distributable cash flow, in certain of our rate-regulated businesses, maintenance capital expenditures are included in their respective rate bases on which we earn a regulated return and recover depreciation through future tolls.

The following provides a breakdown of maintenance capital expenditures:

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
Canadian Natural Gas Pipelines	181	96	300	190
U.S. Natural Gas Pipelines	217	189	512	404
Other	44	57	176	264
<b>Maintenance capital expenditures including equity investments</b>	<b>442</b>	<b>342</b>	<b>988</b>	<b>858</b>

**CASH USED IN INVESTING ACTIVITIES**

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
<b>Capital spending</b>				
Capital expenditures	(2,031)	(1,444)	(5,383)	(3,262)
Capital projects in development	(37)	(62)	(135)	(219)
Contributions to equity investments	(475)	(286)	(1,140)	(570)
	(2,543)	(1,792)	(6,658)	(4,051)
Restricted cash	—	12,987	—	—
Acquisitions, net of cash acquired	—	(12,609)	—	(13,608)
Proceeds from sales of assets, net of transaction costs	—	—	4,147	6
Other distributions from equity investments	—	—	362	725
Deferred amounts and other	164	(12)	(87)	20
<b>Net cash used in investing activities</b>	<b>(2,379)</b>	<b>(1,426)</b>	<b>(2,236)</b>	<b>(16,908)</b>

Capital expenditures in 2017 were primarily related to:

- expansion of Columbia Gas and Columbia Gulf pipelines
- expansion of the NGTL System
- construction of Mexico pipelines
- expansion of the Canadian Mainline
- capital additions to our ANR pipeline
- construction of the Napanee power generating facility.

Costs incurred on Capital projects in development primarily related to spending on the Energy East and LNG-related pipeline projects.



## THIRD QUARTER 2017

Contributions to equity investments have increased in 2017 compared to 2016 primarily due to our investments in Sur de Texas, Bruce Power and Northern Border, partially offset by decreased contributions to Grand Rapids which is now in service. Contributions to equity investments also includes our proportionate share of Sur de Texas debt financing requirements.

Restricted cash in 2016 represented the amount held in escrow at June 30, 2016 for the purchase of Columbia on July 1, 2016.

In second quarter 2017, we closed the sale of our U.S. Northeast power generating assets for net proceeds of \$4,147 million.

Other distributions from equity investments reflects Bruce Power financings undertaken to fund its capital program and make distributions to its partners. In second quarter 2016, Bruce Power issued senior notes in the capital markets and borrowed under a bank credit facility which resulted in \$725 million being received by us. In first quarter 2017, Bruce Power issued additional senior notes in the capital markets which resulted in \$362 million being received by us.

**CASH PROVIDED BY/(USED IN) FINANCING ACTIVITIES**

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
Notes payable issued/(repaid), net	451	(423)	1,232	(100)
Long-term debt issued, net of issue costs	1,151	6	1,968	12,333
Long-term debt repaid	(46)	(53)	(5,515)	(2,343)
Junior subordinated notes issued, net of issue costs	(3)	1,551	3,468	1,551
Advances (to)/from affiliate, net	(15)	(5)	(15)	2,131
Dividends and distributions paid	(610)	(474)	(1,788)	(1,360)
Common shares issued	190	—	591	2,471
Partnership units of TC PipeLines, LP issued, net of issue costs	43	45	162	151
Common units of Columbia Pipeline Partners LP acquired	—	—	(1,205)	—
<b>Net cash provided by/(used in) financing activities</b>	<b>1,161</b>	<b>647</b>	<b>(1,102)</b>	<b>14,834</b>

**LONG-TERM DEBT ISSUED**

The following table outlines significant debt issuances:

(unaudited - millions of \$) Company	Issue date	Type	Maturity date	Amount	Interest rate
<b>TRANSCANADA PIPELINES LIMITED</b>					
	September 2017	Medium Term Notes	March 2028	300	3.39%
	September 2017	Medium Term Notes	September 2047	700	4.33%
<b>TUSCARORA GAS TRANSMISSION COMPANY</b>					
	August 2017	Term Loan	August 2020	US 25	Floating
<b>TC PIPELINES, LP</b>					
	May 2017	Senior Unsecured Notes	May 2027	US 500	3.90%

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**LONG-TERM DEBT REPAYED**

The following table outlines significant debt repaid:

(unaudited - millions of \$) Company	Retirement date	Type	Amount	Interest rate
<b>TUSCARORA GAS TRANSMISSION COMPANY</b>				
	August 2017	Senior Secured Notes	US 12	3.82%
<b>TRANSCANADA PIPELINES LIMITED</b>				
	June 2017	Acquisition Bridge Facility	US 1,513	Floating
	February 2017	Acquisition Bridge Facility	US 500	Floating
	January 2017	Medium Term Notes	300	5.10%
<b>TRANSCANADA PIPELINE USA LTD.</b>				
	June 2017	Acquisition Bridge Facility	US 630	Floating
	April 2017	Acquisition Bridge Facility	US 1,070	Floating

The acquisition bridge facilities were put into place to finance a portion of the Columbia acquisition. Proceeds from the sales of the U.S. Northeast power assets were used to fully retire the remaining acquisition bridge facilities in second quarter 2017.

**JUNIOR SUBORDINATED NOTES ISSUED**

(unaudited - millions of \$) Company	Issue date	Type	Maturity date	Amount	Interest rate
<b>TRANSCANADA PIPELINES LIMITED</b>					
	May 2017	Junior Subordinated Notes <sup>1,2</sup>	May 2077	1,500	4.90%
	March 2017	Junior Subordinated Notes <sup>1,2</sup>	March 2077	US 1,500	5.55%

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

<sup>2</sup> The Junior subordinated notes were issued to TransCanada Trust (the Trust), a financing trust subsidiary wholly-owned by TCPL. While the obligations of the Trust are fully and unconditionally guaranteed by TCPL on a subordinated basis, the Trust is not consolidated in TCPL's financial statements because TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are junior subordinated notes of TCPL.

In May 2017, the Trust issued \$1.5 billion of Trust Notes - Series 2017-B (Trust Notes) to third party investors with a fixed interest rate of 4.65 per cent for the first ten years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for \$1.5 billion of junior subordinated notes of TCPL at an initial fixed rate of 4.90 per cent, including a 0.25 per cent administration charge. The rate will reset commencing May 2027 until May 2047 to the then three month Bankers' Acceptance rate plus 3.33 per cent per annum; from May 2047 until May 2077, the interest rate will reset to the then three month Bankers' Acceptance rate plus 4.08 per cent per annum. The junior subordinated notes are callable at TCPL's option at any time on or after May 18, 2027 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

In March 2017, the Trust issued US\$1.5 billion of Trust Notes - Series 2017-A (Trust Notes) to third party investors with a fixed interest rate of 5.30 per cent for the first ten years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for US\$1.5 billion of junior subordinated notes of TCPL at an initial fixed rate of 5.55 per cent, including a 0.25 per cent administration charge. The rate will reset commencing March 2027 until March 2047 to the then three month LIBOR plus 3.458 per cent per annum; from March 2047 until March 2077, the interest rate will reset to the then three month LIBOR plus 4.208 per cent per annum. The junior subordinated notes are callable at TCPL's option at any time on or after March 15, 2027 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

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

**COMMON SHARES ISSUED**

We issued the following common shares to TransCanada during the year:

- 3.1 million shares on October 31, 2017 for proceeds of \$189 million
- 3.0 million shares on July 31, 2017 for proceeds of \$190 million
- 3.3 million shares on April 28, 2017 for proceeds of \$214 million
- 3.0 million shares on January 31, 2017 for proceeds of \$187 million.

**TC PIPELINES, LP ATM EQUITY ISSUANCE PROGRAM**

During the nine months ended September 30, 2017, 2.2 million common units were issued under the TC PipeLines, LP ATM program generating net proceeds of approximately US\$124 million. At September 30, 2017, our ownership interest in TC PipeLines, LP was 26.0 per cent as a result of issuances under the ATM program and resulting dilution.

**DIVIDENDS**

On November 8, 2017, we declared quarterly dividends as follows:

**Quarterly dividend on our common shares**

The dividend declared for the quarter ending December 31, 2017 is equal to the quarterly dividend to be paid on TransCanada's issued and outstanding common shares at the close of business on December 29, 2017.

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**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 November 8, 2017, we had a total of \$11.0 billion of committed revolving and demand credit facilities, including:

Amount	Unused capacity	Borrower	Description	Matures
<b>Committed, syndicated, revolving, extendible, senior unsecured credit facilities:</b>				
\$3.0 billion	\$3.0 billion	TCPL	Supports TCPL's Canadian dollar commercial paper program and for general corporate purposes	December 2021
US\$2.0 billion	US\$2.0 billion	TCPL	Supports TCPL's U.S. dollar commercial paper program and for general corporate purposes	December 2017
US\$1.0 billion	US\$1.0 billion	TCPL USA	Used for TCPL USA general corporate purposes, guaranteed by TCPL	December 2017
US\$1.0 billion	US\$0.4 billion	Columbia	Used for Columbia general corporate purposes, guaranteed by TCPL	December 2017
US\$0.5 billion	US\$0.5 billion	TAIL	Supports TAIL's U.S. dollar commercial paper program, guaranteed by TCPL and for general corporate purposes	December 2017
<b>Demand senior unsecured revolving credit facilities:</b>				
\$2.1 billion	\$0.7 billion	TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity	Demand
MXN\$5.0 billion	MXN\$4.7 billion	Mexican subsidiary	Used for Mexico general corporate purposes, guaranteed by TCPL	Demand

At November 8, 2017, our operated affiliates had an additional \$0.6 billion of undrawn capacity on committed credit facilities.

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

**RELATED PARTY DEBT FINANCING**

Related party debt outstanding at September 30, 2017 consists of the following credit facility due to affiliate:

Amount	Description	Matures
\$2.3 billion	Unsecured credit facility agreement with TransCanada used to repay indebtedness and for working capital and general corporate purposes.	Demand

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## CONTRACTUAL OBLIGATIONS

Our capital commitments are consistent with those reported at December 31, 2016. Decreased commitments for the ongoing construction of the Sur de Texas natural gas pipeline and the Napanee power generating facility were mostly offset by increased commitments for the Columbia Gas and Columbia Gulf growth projects. Transportation by others commitments have increased by approximately \$0.6 billion since December 31, 2016 primarily related to Canadian Mainline contracts. Other Energy commitments have decreased by approximately \$0.4 billion since December 31, 2016 as a result of the sale of our U.S. Northeast power assets.

Our operating lease commitments at December 31, 2016 included future payments related to our U.S. Northeast power business. As a result of the completion of the sale of our thermal power assets in June 2017, the remaining future obligations reported at December 31, 2016 have decreased by: \$2 million in 2017, \$52 million in 2018, \$34 million in 2019 and \$102 million in 2022 and beyond.

There were no other material changes to our contractual obligations in third quarter 2017 or to payments due in the next five years or after. See the MD&A in our 2016 Annual Report for more information about our contractual obligations.

## Financial risks and financial instruments

We are exposed to liquidity risk, counterparty credit risk and market risk, and have strategies, policies and limits in place to mitigate their impact on our earnings, cash flow and, ultimately, shareholder value. These are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance.

See our 2016 Annual Report for more information about the risks we face in our business. Our risks have not changed substantially since December 31, 2016, other than described below.

In second quarter 2017, we sold our U.S. Northeast merchant power generation assets and initiated the wind down of our U.S. power marketing operations. We expect to realize the value of the remaining marketing contracts and working capital over time. As a result, our exposure to commodity risk has been reduced.

### LIQUIDITY RISK

We manage our liquidity risk by continuously forecasting our cash flow for a 12 month period to ensure 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.

### COUNTERPARTY CREDIT RISK

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

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

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At September 30, 2017, we had no significant credit losses, no significant credit risk concentration and no significant amounts past due or impaired.

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

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**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 the joint venture as an equity investment. On April 21, 2017, we entered into a MXN\$13.6 billion unsecured revolving credit facility with the joint venture, which bears interest at a floating rate and matures in March 2022.

**FOREIGN EXCHANGE AND INTEREST RATE RISK**

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

A portion of our businesses generate earnings in U.S. dollars, but since we report our financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect our net income. As our U.S. dollar-denominated operations continue to grow, this exposure increases. The majority of this risk is offset by interest expense on U.S. dollar-denominated debt and by using foreign exchange derivatives.

We have floating interest rate debt which subjects us to interest rate cash flow risk. We manage this using a combination of interest rate swaps and options.

**Average exchange rate - U.S. to Canadian dollars**

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

<b>three months ended September 30, 2017</b>	<b>1.25</b>
three months ended September 30, 2016	1.31
<b>nine months ended September 30, 2017</b>	<b>1.31</b>
nine months ended September 30, 2016	1.32

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

**Significant U.S. dollar-denominated amounts**

(unaudited - millions of US\$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
U.S. Natural Gas Pipelines comparable EBIT	<b>269</b>	290	<b>998</b>	635
Mexico Natural Gas Pipelines comparable EBIT	<b>76</b>	73	<b>254</b>	141
U.S. Liquids Pipelines comparable EBIT	<b>135</b>	117	<b>416</b>	360
U.S. Power comparable EBIT	<b>22</b>	130	<b>108</b>	223
AFUDC on U.S. dollar-denominated projects	<b>81</b>	55	<b>168</b>	149
Interest on U.S. dollar-denominated long-term debt	<b>(314)</b>	(315)	<b>(954)</b>	(811)
Capitalized interest on U.S. dollar-denominated capital expenditures	<b>1</b>	6	<b>2</b>	22
U.S. dollar non-controlling interests and other	<b>(35)</b>	(38)	<b>(144)</b>	(138)
	<b>235</b>	318	<b>848</b>	581

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**Net investment hedge**

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

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

(unaudited - millions of Canadian \$, unless noted otherwise)	September 30, 2017		December 31, 2016	
	Fair value <sup>1</sup>	Notional or principal amount	Fair value <sup>1</sup>	Notional or principal amount
U.S. dollar cross-currency interest rate swaps (maturing 2017 to 2019) <sup>2</sup>	(222)	US 1,400	(425)	US 2,350
U.S. dollar foreign exchange forward contracts	—	—	(7)	US 150
	<b>(222)</b>	<b>US 1,400</b>	<b>(432)</b>	<b>US 2,500</b>

<sup>1</sup> Fair values equal carrying values.

<sup>2</sup> In the three and nine months ended September 30, 2017, condensed consolidated net income includes net realized gains of \$1 million and \$3 million, respectively, (2016 - gains of \$1 million and \$5 million, respectively) related to the interest component of cross-currency swap settlements which are reported within interest expense.

The notional amounts and fair value of U.S. dollar-denominated debt designated as a net investment hedge were as follows:

(unaudited - millions of Canadian \$, unless noted otherwise)	September 30, 2017	December 31, 2016
Notional amount	<b>24,900 (US 19,900)</b>	26,600 (US 19,800)
Fair value	<b>28,300 (US 22,600)</b>	29,400 (US 21,900)

**FINANCIAL INSTRUMENTS**

All financial instruments, including both derivative and non-derivative 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. We apply hedge accounting to derivative instruments that qualify and are designated for hedge accounting treatment.

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

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**Balance sheet presentation of derivative instruments**

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

(unaudited - millions of \$)	September 30, 2017	December 31, 2016
Other current assets	286	376
Intangible and other assets	89	133
Accounts payable and other	(453)	(607)
Other long-term liabilities	(155)	(330)
	<b>(233)</b>	<b>(428)</b>

**Unrealized and realized gains/(losses) of derivative instruments**

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

(unaudited - millions of \$, pre-tax)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
<b>Derivative instruments held for trading<sup>1</sup></b>				
Amount of unrealized gains/(losses) in the period				
Commodities <sup>2</sup>	45	(97)	(102)	23
Foreign exchange	33	—	89	47
Interest rate	(1)	—	(1)	—
Amount of realized (losses)/gains in the period				
Commodities	(82)	(23)	(167)	(165)
Foreign exchange	19	(5)	10	52
Interest rate	1	—	1	—
<b>Derivative instruments in hedging relationships</b>				
Amount of realized gains/(losses) in the period				
Commodities	4	(15)	17	(155)
Foreign exchange	—	5	5	(101)
Interest rate	—	1	1	4

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

<sup>2</sup> In the three and nine months ended September 30, 2017, there were no gains or losses included in net income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur (2016 - nil and a net loss of \$42 million, respectively).



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**Derivatives in cash flow hedging relationships**

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

(unaudited - millions of \$, pre-tax)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
Change in fair value of derivative instruments recognized in OCI (effective portion) <sup>1</sup>				
Commodities	2	7	5	33
Foreign exchange	—	(5)	—	—
Interest rate	(1)	4	—	—
	1	6	5	33
Reclassification of (losses)/gains on derivative instruments from AOCI to net income (effective portion) <sup>1</sup>				
Commodities <sup>2</sup>	(4)	(7)	(15)	54
Foreign exchange <sup>3</sup>	—	5	—	—
Interest rate <sup>4</sup>	4	3	13	11
	—	1	(2)	65
Gains/(losses) on derivative instruments recognized in net income (ineffective portion)				
Commodities <sup>2</sup>	—	14	—	(1)
	—	14	—	(1)

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

<sup>2</sup> Reported within revenues on the condensed consolidated statement of income.

<sup>3</sup> Reported within interest income and other on the condensed consolidated statement of income.

<sup>4</sup> Reported within interest expense on the condensed consolidated statement of income.

**Credit risk related contingent features of derivative instruments**

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

Based on contracts in place and market prices at September 30, 2017, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was \$11 million (December 31, 2016 – \$19 million), with collateral provided in the normal course of business of nil (December 31, 2016 – nil). If the credit-risk-related contingent features in these agreements were triggered on September 30, 2017, we would have been required to provide additional collateral of \$11 million (December 31, 2016 – \$19 million) to our counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

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

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## 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, 2017, 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.

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

Assets attributable to Columbia represented approximately 18.1 per cent of our total assets as of September 30, 2017 and revenues attributable to Columbia for the nine months ended September 30, 2017 represented approximately 14.6 per cent of our total revenues for that period.

There were no changes in third quarter 2017 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 2016 Annual Report.

Our significant accounting policies have remained unchanged since December 31, 2016 other than described below. A summary of our significant accounting policies is included in our 2016 Annual Report.

#### Changes in accounting policies for 2017

##### **Inventory**

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

##### **Derivatives and hedging**

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

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### **Equity method investments**

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

### **Employee share-based payments**

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

### **Consolidation**

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

### **Future accounting changes**

#### **Revenue from contracts with customers**

In 2014, the FASB issued new guidance on revenue from contracts with customers. The new guidance requires that an entity recognize revenue in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in an amount that reflects the total consideration to which it expects to be entitled during the term of the contract in exchange for those goods or services. The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue and the related cash flows. We will adopt the new standard on the effective date of January 1, 2018. There are two methods in which the new standard can be adopted: (1) a full retrospective approach with restatement of all prior periods presented, or (2) a modified retrospective approach with a cumulative-effect adjustment as of the date of adoption. We will adopt the standard using the modified retrospective approach with the cumulative-effect of the adjustment recognized at the date of adoption, subject to allowable and elected practical expedients.

We have identified all existing customer contracts that are within the scope of the new guidance and are on schedule in the process of analyzing individual contracts or groups of contracts by operating segment to identify any significant changes in how revenues are recognized as a result of implementing the new guidance. We have completed our analysis of the Liquids Pipelines and Energy operating segments and have not identified any material differences in the amount and timing of revenue recognition. We are currently analyzing our Canadian, U.S. and Mexico Natural Gas Pipelines and have not yet concluded on the impact of the new guidance on these operating segments. As we continue our contract analysis, we will obtain the information necessary to quantify the cumulative-effect adjustment, if any, on prior period revenues and revenue recognized going forward, and we are monitoring additional authoritative or interpretive guidance related to the new standard as it becomes available.

Although consolidated revenues may not be materially impacted by the new guidance, we currently anticipate significant changes to disclosures based on the additional requirements prescribed. These new disclosures include information regarding the significant judgments used in evaluating when and how revenue is recognized and

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information related to contract assets and liabilities. In addition, the new guidance requires that our revenue recognition policy disclosure includes additional detail regarding the various performance obligations and the nature, amount, timing and estimates of revenue and cash flows generated from contracts with customers. We continue to develop and evaluate disclosures required with a particular focus on the scope of contracts subject to disclosure of remaining performance obligations and continue to address any system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance.

**Financial instruments**

In January 2016, the FASB issued new guidance on the accounting for equity investments and financial liabilities. The new guidance will change the income statement effect of equity investments and the recognition of changes in the fair value of financial liabilities when the fair value option is elected. The new guidance also requires us to assess valuation allowances for deferred tax assets related to available for sale debt securities in combination with their other deferred tax assets. This new guidance is effective January 1, 2018 and a method of adoption is specified for each component of the guidance. We are currently evaluating the impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

**Leases**

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

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

**Measurement of credit losses on financial instruments**

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

**Income taxes**

In October 2016, the FASB issued new guidance on the income tax effects of intra-entity transfers of assets other than inventory. The new guidance requires the recognition of deferred and current income taxes for an intra-entity asset transfer when the transfer occurs. The new guidance is effective January 1, 2018 and will be applied using a modified retrospective approach. We are currently evaluating the impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

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### **Restricted cash**

In November 2016, the FASB issued new guidance on restricted cash and cash equivalents on the statement of cash flows. The new guidance requires that the statement of cash flows explain the change during the period in the total cash and cash equivalents balance, and amounts generally described as restricted cash or restricted cash equivalents. Restricted cash and cash equivalents will be included with Cash and cash equivalents when reconciling the beginning of year and end of year total amounts on the statement of cash flows. This new guidance is effective January 1, 2018 and will be applied retrospectively.

### **Goodwill impairment**

In January 2017, the FASB issued new guidance on simplifying the test for goodwill impairment by eliminating Step 2 of the impairment test, which is the requirement to calculate the implied fair value of goodwill to measure the impairment charge. Instead, entities will record an impairment charge based on the excess of a reporting unit's carrying amount over its fair value. This new guidance is effective January 1, 2020 and will be applied prospectively, however, early adoption is permitted.

### **Employee post-retirement benefits**

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

### **Amortization on purchased callable debt securities**

In March 2017, the FASB issued new guidance that shortens the amortization period for the premium on certain purchased callable debt securities by requiring entities to amortize the premium to the earliest call date. This new guidance is effective January 1, 2019 and will be applied using a modified retrospective approach. We are currently evaluating the impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

### **Hedge accounting**

In August 2017, the FASB issued new guidance on hedge accounting, making more financial and non-financial hedging strategies eligible for hedge accounting. The new guidance also amends the presentation requirements relating to the change in fair value of a derivative and additional disclosure requirements include cumulative basis adjustments for fair value hedges and the effect of hedging on individual statement of income line items. This new guidance is effective January 1, 2019, with early adoption permitted, and will be applied prospectively with a cumulative-effect adjustment to opening retained earnings on adoption. We are currently evaluating the impact of the adoption of this guidance, however we do not anticipate a material impact on our consolidated financial statements.

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## Reconciliation of non-GAAP measures

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
<b>Comparable EBITDA</b>				
Canadian Natural Gas Pipelines	544	549	1,575	1,598
U.S. Natural Gas Pipelines	482	522	1,753	1,112
Mexico Natural Gas Pipelines	118	111	403	213
Liquids Pipelines	303	278	947	850
Energy	224	418	816	977
Corporate	(4)	8	(20)	7
<b>Comparable EBITDA</b>	<b>1,667</b>	1,886	<b>5,474</b>	4,757
Depreciation and amortization	(506)	(527)	(1,532)	(1,425)
<b>Comparable EBIT</b>	<b>1,161</b>	1,359	<b>3,942</b>	3,332
Specific items:				
Net (loss)/gain on sales of U.S. Northeast power assets	(12)	(5)	469	(5)
Integration and acquisition related costs – Columbia	(32)	(96)	(91)	(132)
Keystone XL asset costs	(10)	(14)	(23)	(37)
Foreign exchange gain/(loss) – inter-affiliate loan	7	—	(1)	—
Ravenswood goodwill impairment	—	(1,085)	—	(1,085)
Alberta PPA terminations	—	—	—	(240)
Restructuring costs	—	—	—	(14)
TC Offshore loss on sale	—	—	—	(4)
Risk management activities <sup>1</sup>	45	(81)	(102)	22
<b>Segmented earnings</b>	<b>1,159</b>	78	<b>4,194</b>	1,837

<sup>1</sup> Risk management activities (unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
Canadian Power	1	(4)	5	3
U.S. Power	59	(73)	(97)	16
Natural Gas Storage	4	4	5	9
Liquids marketing	(19)	(8)	(15)	(6)
<b>Total unrealized (losses)/gains from risk management activities</b>	<b>45</b>	(81)	<b>(102)</b>	22

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## Quarterly results

### SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

(unaudited - millions of \$)	2017				2016			2015
	Third	Second	First	Fourth	Third	Second	First	Fourth
Revenues	<b>3,242</b>	3,217	3,391	3,619	3,632	2,751	2,503	2,851
Net income/(loss) attributable to controlling interests and to common shares	<b>636</b>	909	672	(334)	(118)	497	276	(2,436)
Comparable earnings	<b>638</b>	687	727	650	639	395	518	475

### FACTORS AFFECTING QUARTERLY FINANCIAL INFORMATION BY BUSINESS SEGMENT

Quarter-over-quarter revenues and net income sometimes fluctuate, the causes of which 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:

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

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

- developments outside of the normal course of operations
- newly constructed assets being placed in service
- regulatory decisions
- short term revenues from available capacity not committed under long term contract, driven by changing short term market conditions.

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

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

### FACTORS AFFECTING FINANCIAL INFORMATION BY QUARTER

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

Comparable earnings exclude the unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives generally provide effective

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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.

In third quarter 2017, comparable earnings excluded:

- an after-tax charge of \$30 million for integration-related costs associated with the acquisition of Columbia
- an after-tax charge of \$12 million for post-closing and income tax adjustments related to the monetization of our U.S. Northeast power business
- an after-tax charge of \$8 million related to the maintenance of Keystone XL assets which is being expensed pending further advancement of the project.

In second quarter 2017, comparable earnings excluded:

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

In first quarter 2017, comparable earnings excluded:

- a charge of \$24 million after tax for integration-related costs associated with the acquisition of Columbia
- a charge of \$10 million after tax for costs related to the monetization of our U.S. Northeast power business
- a charge of \$7 million after tax related to the maintenance of Keystone XL assets which are being expensed pending further advancement of the project
- a \$7 million income tax recovery related to the realized loss on a third party sale of Keystone XL project assets. A provision for the expected pre-tax loss on these assets was included in our 2015 impairment charge, but the related income tax recoveries could not be recorded until realized.

In fourth quarter 2016, comparable earnings excluded:

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

In third quarter 2016, comparable earnings excluded:

- a \$656 million after-tax impairment on Ravenswood goodwill. As a result of information received during the process to monetize our U.S. Northeast Power business in third quarter 2016, it was determined that the fair value of Ravenswood no longer exceeded its carrying value
- costs associated with the acquisition of Columbia including a charge of \$67 million after tax primarily related to retention, severance and integration expenses



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- \$28 million of income tax recoveries related to the realized loss on a third party sale of Keystone XL plant and equipment. A provision for the expected loss on these assets was included in our fourth quarter 2015 impairment charge but the related tax recoveries could not be recorded until realized
- a charge of \$9 million after tax related to Keystone XL costs for the maintenance and liquidation of project assets which are being expensed pending further advancement of the project
- a \$3 million after-tax charge related to the monetization of our U.S. Northeast Power business.

In second quarter 2016, comparable earnings excluded:

- a charge of \$10 million related to costs associated with the acquisition of Columbia
- a charge of \$9 million after tax related to Keystone XL costs for the maintenance and liquidation of project assets which are being expensed pending further advancement of the project
- a charge of \$10 million after tax for restructuring charges mainly related to expected future losses under lease commitments.

In first quarter 2016, comparable earnings excluded:

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

In fourth quarter 2015, comparable earnings excluded:

- a \$2,891 million after-tax impairment charge on the carrying value of our investment in Keystone XL and related projects
- an \$86 million after-tax loss provision related to the sale of TC Offshore which closed in early 2016
- a net charge of \$60 million after tax for our business restructuring and transformation initiative comprised of \$28 million mainly related to 2015 severance costs and a provision of \$32 million for 2016 planned severance costs and expected future losses under lease commitments. These charges formed part of a restructuring initiative which commenced in 2015 to maximize the effectiveness and efficiency of our existing operations and reduce overall costs
- a \$43 million after-tax charge related to an impairment in value of turbine equipment held for future use in our Energy business
- a charge of \$27 million after tax related to Bruce Power's retirement of debt in conjunction with the merger of the Bruce A and Bruce B partnerships
- a \$199 million positive income adjustment related to the impact on our net income from non-controlling interests of TC PipeLines, LP's impairment of their equity investment in Great Lakes.

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## Condensed consolidated statement of income

(unaudited - millions of Canadian \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
<b>Revenues</b>				
Canadian Natural Gas Pipelines	921	951	2,725	2,677
U.S. Natural Gas Pipelines	811	812	2,684	1,585
Mexico Natural Gas Pipelines	139	121	432	249
Liquids Pipelines	437	440	1,410	1,292
Energy	934	1,308	2,599	3,083
	<b>3,242</b>	<b>3,632</b>	<b>9,850</b>	<b>8,886</b>
<b>Income from Equity Investments</b>	<b>156</b>	<b>154</b>	<b>527</b>	<b>355</b>
<b>Operating and Other Expenses</b>				
Plant operating costs and other	976	1,177	2,980	2,646
Commodity purchases resold	621	783	1,711	1,628
Property taxes	127	136	442	405
Depreciation and amortization	506	527	1,539	1,425
Goodwill and other asset impairment charges	—	1,085	—	1,296
	<b>2,230</b>	<b>3,708</b>	<b>6,672</b>	<b>7,400</b>
<b>(Loss)/Gain on Sale of Assets</b>	<b>(9)</b>	<b>—</b>	<b>489</b>	<b>(4)</b>
<b>Financial Charges</b>				
Interest expense	522	538	1,578	1,369
Allowance for funds used during construction	(145)	(110)	(367)	(322)
Interest income and other	(83)	(18)	(192)	(128)
	<b>294</b>	<b>410</b>	<b>1,019</b>	<b>919</b>
<b>Income/(Loss) before Income Taxes</b>	<b>865</b>	<b>(332)</b>	<b>3,175</b>	<b>918</b>
<b>Income Tax Expense/(Recovery)</b>				
Current	7	15	129	104
Deferred	178	(281)	640	(25)
	<b>185</b>	<b>(266)</b>	<b>769</b>	<b>79</b>
<b>Net Income/(Loss)</b>	<b>680</b>	<b>(66)</b>	<b>2,406</b>	<b>839</b>
Net income attributable to non-controlling interests	44	52	189	184
<b>Net Income/(Loss) Attributable to Controlling Interests and to Common Shares</b>	<b>636</b>	<b>(118)</b>	<b>2,217</b>	<b>655</b>

See accompanying notes to the condensed consolidated financial statements.

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## Condensed consolidated statement of comprehensive income

(unaudited - millions of Canadian \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
<b>Net Income/(Loss)</b>	<b>680</b>	(66)	<b>2,406</b>	839
<b>Other Comprehensive (Loss)/Income, Net of Income Taxes</b>				
Foreign currency translation (losses)/gains on net investment in foreign operations	<b>(370)</b>	55	<b>(721)</b>	(152)
Reclassification of foreign currency translation gains on net investment in foreign operations	—	—	<b>(77)</b>	—
Change in fair value of net investment hedges	<b>(1)</b>	(1)	<b>(3)</b>	(9)
Change in fair value of cash flow hedges	<b>1</b>	5	<b>4</b>	21
Reclassification to net income of gains and losses on cash flow hedges	—	—	<b>(1)</b>	40
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	<b>2</b>	—	<b>2</b>	—
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	<b>4</b>	4	<b>11</b>	12
Other comprehensive income on equity investments	<b>3</b>	4	<b>6</b>	11
Other comprehensive (loss)/income (Note 10)	<b>(361)</b>	67	<b>(779)</b>	(77)
<b>Comprehensive Income</b>	<b>319</b>	1	<b>1,627</b>	762
Comprehensive (loss)/income attributable to non-controlling interests	<b>(25)</b>	76	<b>31</b>	104
<b>Comprehensive Income/(Loss) Attributable to Controlling Interests and to Common Shares</b>	<b>344</b>	(75)	<b>1,596</b>	658

See accompanying notes to the condensed consolidated financial statements.

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## Condensed consolidated statement of cash flows

(unaudited - millions of Canadian \$)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
<b>Cash Generated from Operations</b>				
Net income/(loss)	680	(66)	2,406	839
Depreciation and amortization	506	527	1,539	1,425
Goodwill and other asset impairment charges	—	1,085	—	1,296
Deferred income taxes	178	(281)	640	(25)
Income from equity investments	(156)	(154)	(527)	(355)
Distributions received from operating activities of equity investments	296	185	743	625
Employee post-retirement benefits funding, net of expense	(73)	4	(64)	(5)
Loss/(gain) on sale of assets	9	—	(489)	4
Equity allowance for funds used during construction	(107)	(71)	(249)	(195)
Unrealized (gains)/losses on financial instruments	(77)	82	14	(71)
Other	(5)	1	(1)	24
(Increase)/decrease in operating working capital	(83)	(7)	(223)	28
Net cash provided by operations	1,168	1,305	3,789	3,590
<b>Investing Activities</b>				
Capital expenditures	(2,031)	(1,444)	(5,383)	(3,262)
Capital projects in development	(37)	(62)	(135)	(219)
Contributions to equity investments	(475)	(286)	(1,140)	(570)
Restricted cash	—	12,987	—	—
Acquisitions, net of cash acquired	—	(12,609)	—	(13,608)
Proceeds from sales of assets, net of transaction costs	—	—	4,147	6
Other distributions from equity investments	—	—	362	725
Deferred amounts and other	164	(12)	(87)	20
Net cash used in investing activities	(2,379)	(1,426)	(2,236)	(16,908)
<b>Financing Activities</b>				
Notes payable issued/(repaid), net	451	(423)	1,232	(100)
Long-term debt issued, net of issue costs	1,151	6	1,968	12,333
Long-term debt repaid	(46)	(53)	(5,515)	(2,343)
Junior subordinated notes issued, net of issue costs	(3)	1,551	3,468	1,551
Advances (to)/from affiliate, net	(15)	(5)	(15)	2,131
Dividends on common shares	(544)	(397)	(1,573)	(1,159)
Distributions paid to non-controlling interests	(66)	(77)	(215)	(201)
Common shares issued	190	—	591	2,471
Partnership units of TC PipeLines, LP issued, net of issue costs	43	45	162	151
Common units of Columbia Pipeline Partners LP acquired	—	—	(1,205)	—
Net cash provided by/(used in) financing activities	1,161	647	(1,102)	14,834
<b>Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents</b>	(16)	3	(35)	(127)
<b>(Decrease)/Increase in Cash and Cash Equivalents</b>	(66)	529	416	1,389
<b>Cash and Cash Equivalents</b>				
Beginning of period	1,449	1,673	967	813
<b>Cash and Cash Equivalents</b>				
End of period	1,383	2,202	1,383	2,202

See accompanying notes to the condensed consolidated financial statements.

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## Condensed consolidated balance sheet

(unaudited - millions of Canadian \$)	September 30, 2017	December 31, 2016
<b>ASSETS</b>		
<b>Current Assets</b>		
Cash and cash equivalents	1,383	967
Accounts receivable	2,822	2,093
Inventories	390	368
Assets held for sale	431	3,717
Other	743	908
	<b>5,769</b>	<b>8,053</b>
<b>Plant, Property and Equipment</b>	<b>55,842</b>	<b>54,475</b>
net of accumulated depreciation of \$23,257 and \$22,263, respectively		
<b>Equity Investments</b>	<b>6,349</b>	<b>6,544</b>
<b>Regulatory Assets</b>	<b>1,309</b>	<b>1,322</b>
<b>Goodwill</b>	<b>13,076</b>	<b>13,958</b>
<b>Intangible and Other Assets</b>	<b>3,150</b>	<b>2,947</b>
<b>Restricted Investments</b>	<b>810</b>	<b>642</b>
	<b>86,305</b>	<b>87,941</b>
<b>LIABILITIES</b>		
<b>Current Liabilities</b>		
Notes payable	1,963	774
Accounts payable and other	4,086	3,876
Dividends payable	548	491
Due to affiliate	2,343	2,358
Accrued interest	541	595
Liabilities related to assets held for sale	18	86
Current portion of long-term debt	4,216	1,838
	<b>13,715</b>	<b>10,018</b>
<b>Regulatory Liabilities</b>	<b>2,512</b>	<b>2,121</b>
<b>Other Long-Term Liabilities</b>	<b>745</b>	<b>1,183</b>
<b>Deferred Income Tax Liabilities</b>	<b>8,069</b>	<b>7,662</b>
<b>Long-Term Debt</b>	<b>30,414</b>	<b>38,312</b>
<b>Junior Subordinated Notes</b>	<b>7,004</b>	<b>3,931</b>
	<b>62,459</b>	<b>63,227</b>
<b>Common Units Subject to Rescission or Redemption</b>	<b>—</b>	<b>1,179</b>
<b>EQUITY</b>		
Common shares, no par value	21,572	20,981
Issued and outstanding:	September 30, 2017 - 868 million shares	
	December 31, 2016 - 859 million shares	
Additional paid-in capital	—	211
Retained earnings	2,038	1,577
Accumulated other comprehensive loss	(1,581)	(960)
<b>Controlling Interests</b>	<b>22,029</b>	<b>21,809</b>
Non-controlling interests	1,817	1,726
	<b>23,846</b>	<b>23,535</b>
	<b>86,305</b>	<b>87,941</b>

**Commitments, Contingencies and Guarantees** (Note 14)**Variable Interest Entities** (Note 16)**Subsequent Events** (Note 17)

See accompanying notes to the condensed consolidated financial statements.

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## Condensed consolidated statement of equity

(unaudited - millions of Canadian \$)	nine months ended September 30	
	2017	2016
<b>Common Shares</b>		
Balance at beginning of period	20,981	16,320
Shares issued	591	2,471
Balance at end of period	21,572	18,791
<b>Additional Paid-In Capital</b>		
Balance at beginning of period	211	210
Issuance of stock options	9	12
Dilution impact from TC PipeLines, LP units issued	18	17
Impact of asset drop downs to TC PipeLines, LP	(202)	(38)
Impact of Columbia Pipeline Partners LP acquisition	(171)	—
Reclassification of Additional Paid-In Capital deficit to Retained Earnings	135	—
Balance at end of period	—	201
<b>Retained Earnings</b>		
Balance at beginning of period	1,577	2,989
Net income attributable to controlling interests	2,217	655
Common share dividends	(1,633)	(1,246)
Adjustment related to employee share-based payments (Note 2)	12	—
Reclassification of Additional Paid-In Capital deficit to Retained Earnings	(135)	—
Balance at end of period	2,038	2,398
<b>Accumulated Other Comprehensive Loss</b>		
Balance at beginning of period	(960)	(939)
Other comprehensive loss	(621)	3
Balance at end of period	(1,581)	(936)
<b>Equity Attributable to Controlling Interests</b>		
	22,029	20,454
<b>Equity Attributable to Non-Controlling Interests</b>		
Balance at beginning of period	1,726	1,717
Acquisition of non-controlling interests in Columbia Pipelines Partners LP	—	1,051
Net income attributable to non-controlling interests	189	184
Other comprehensive loss attributable to non-controlling interests	(158)	(80)
Issuance of TC PipeLines, LP units		
Proceeds, net of issue costs	162	151
Decrease in TCPL's ownership of TC PipeLines, LP	(29)	(28)
Reclassification from/(to) common units of TC PipeLines, LP subject to rescission	106	(106)
Distributions declared to non-controlling interests	(212)	(200)
Impact of Columbia Pipeline Partners LP acquisition	33	—
Balance at end of period	1,817	2,689
<b>Total Equity</b>	<b>23,846</b>	<b>23,143</b>

See accompanying notes to the condensed consolidated financial statements.

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## Notes to condensed consolidated financial statements (unaudited)

### 1. Basis of presentation

These condensed consolidated financial statements of TransCanada Pipelines Limited (TCPL or the Company) have been prepared by management in accordance with U.S. GAAP. The accounting policies applied are consistent with those outlined in TCPL's annual audited consolidated financial statements for the year ended December 31, 2016, except as described in Note 2, Accounting changes. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in TCPL's 2016 Annual Report.

These condensed consolidated financial statements reflect adjustments, all of which are normal recurring adjustments that are, in the opinion of management, necessary to reflect fairly the financial position and results of operations for the respective periods. These condensed consolidated financial statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2016 audited consolidated financial statements included in TCPL's 2016 Annual Report. Certain comparative figures have been reclassified to conform with the current period's presentation.

Earnings for interim periods may not be indicative of results for the fiscal year in the Company's natural gas pipelines segments due to the timing of regulatory decisions and seasonal fluctuations in short-term throughput volumes on U.S. pipelines. Earnings for interim periods may also not be indicative of results for the fiscal year in the Company's Energy segment due to the impact of seasonal weather conditions on customer demand and market pricing in certain of the Company's investments in electrical power generation plants and non-regulated gas storage facilities.

#### **USE OF ESTIMATES AND JUDGEMENTS**

In preparing these financial statements, TCPL is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions. In the opinion of management, these condensed consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies included in the annual audited consolidated financial statements for the year ended December 31, 2016, except as described in Note 2, Accounting changes.

### 2. Accounting changes

#### **CHANGES IN ACCOUNTING POLICIES FOR 2017**

##### **Inventory**

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

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**Derivatives and hedging**

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

**Equity method investments**

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

**Employee share-based payments**

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

**Consolidation**

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

**FUTURE ACCOUNTING CHANGES****Revenue from contracts with customers**

In 2014, the FASB issued new guidance on revenue from contracts with customers. The new guidance requires that an entity recognize revenue in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in an amount that reflects the total consideration to which it expects to be entitled during the term of the contract in exchange for those goods or services. The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue and the related cash flows. The Company will adopt the new standard on the effective date of January 1, 2018. There are two methods in which the new standard can be adopted: (1) a full retrospective approach with restatement of all prior periods presented, or (2) a modified retrospective approach with a cumulative-effect adjustment as of the date of adoption. The Company will adopt the standard using the modified retrospective approach with the cumulative-effect of the adjustment recognized at the date of adoption, subject to allowable and elected practical expedients.

The Company has identified all existing customer contracts that are within the scope of the new guidance and is on schedule in the process of analyzing individual contracts or groups of contracts by operating segment to identify any significant changes in how revenues are recognized as a result of implementing the new guidance. The Company has completed its analysis of the Liquids Pipelines and Energy operating segments and has not identified any material



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differences in the amount and timing of revenue recognition. The Company is currently analyzing its Canadian, U.S. and Mexico Natural Gas Pipelines and has not yet concluded on the impact of the new guidance on these operating segments. The Company continues its contract analysis to obtain the information necessary to quantify the cumulative-effect adjustment, if any, on prior period revenues and revenue recognized going forward, and is monitoring additional authoritative or interpretive guidance related to the new standard as it becomes available.

Although consolidated revenues may not be materially impacted by the new guidance, the Company currently anticipates significant changes to disclosures based on the additional requirements prescribed. These new disclosures include information regarding the significant judgments used in evaluating when and how revenue is recognized and information related to contract assets and liabilities. In addition, the new guidance requires that the Company's revenue recognition policy disclosure includes additional detail regarding the various performance obligations and the nature, amount, timing and estimates of revenue and cash flows generated from contracts with customers. The Company continues to develop and evaluate disclosures required with a particular focus on the scope of contracts subject to disclosure of remaining performance obligations. The Company also continues to address any system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance.

### **Financial instruments**

In January 2016, the FASB issued new guidance on the accounting for equity investments and financial liabilities. The new guidance will change the income statement effect of equity investments and the recognition of changes in the fair value of financial liabilities when the fair value option is elected. The new guidance also requires the Company to assess valuation allowances for deferred tax assets related to available for sale debt securities in combination with their other deferred tax assets. This new guidance is effective January 1, 2018 and a method of adoption is specified for each component of the guidance. The Company is currently evaluating the impact of the adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

### **Leases**

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

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

### **Measurement of credit losses on financial instruments**

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

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**Income taxes**

In October 2016, the FASB issued new guidance on the income tax effects of intra-entity transfers of assets other than inventory. The new guidance requires the recognition of deferred and current income taxes for an intra-entity asset transfer when the transfer occurs. The new guidance is effective January 1, 2018 and will be applied using a modified retrospective approach. The Company is currently evaluating the impact of the adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

**Restricted cash**

In November 2016, the FASB issued new guidance on restricted cash and cash equivalents on the statement of cash flows. The new guidance requires that the statement of cash flows explain the change during the period in the total cash and cash equivalents balance, and amounts generally described as restricted cash or restricted cash equivalents. Restricted cash and cash equivalents will be included with Cash and cash equivalents when reconciling the beginning of year and end of year total amounts on the statement of cash flows. This new guidance is effective January 1, 2018 and will be applied retrospectively.

**Goodwill impairment**

In January 2017, the FASB issued new guidance on simplifying the test for goodwill impairment by eliminating Step 2 of the impairment test, which is the requirement to calculate the implied fair value of goodwill to measure the impairment charge. Instead, entities will record an impairment charge based on the excess of a reporting unit's carrying amount over its fair value. This new guidance is effective January 1, 2020 and will be applied prospectively, however, early adoption is permitted.

**Employee post-retirement benefits**

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

**Amortization on purchased callable debt securities**

In March 2017, the FASB issued new guidance that shortens the amortization period for the premium on certain purchased callable debt securities by requiring entities to amortize the premium to the earliest call date. This new guidance is effective January 1, 2019 and will be applied using a modified retrospective approach. The Company is currently evaluating the impact of the adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

**Hedge accounting**

In August 2017, the FASB issued new guidance on hedge accounting, making more financial and non-financial hedging strategies eligible for hedge accounting. The new guidance also amends the presentation requirements relating to the change in fair value of a derivative and additional disclosure requirements include cumulative basis adjustments for fair value hedges and the effect of hedging on individual statement of income line items. This new guidance is effective January 1, 2019, with early adoption permitted, and will be applied prospectively with a cumulative-effect adjustment to opening retained earnings on adoption. The Company is currently evaluating the impact of the adoption of this guidance, however it does not anticipate a material impact on its consolidated financial statements.





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**TOTAL ASSETS**

(unaudited - millions of Canadian \$)	September 30, 2017	December 31, 2016
Canadian Natural Gas Pipelines	17,010	15,816
U.S. Natural Gas Pipelines	34,897	34,422
Mexico Natural Gas Pipelines	5,470	5,013
Liquids Pipelines	16,436	16,896
Energy	8,979	13,169
Corporate	3,513	2,625
	<b>86,305</b>	<b>87,941</b>

**4. Assets held for sale****Solar Assets**

On October 24, 2017, the Company entered into an agreement to sell its Ontario Solar assets to a third party for approximately \$540 million. The sale is expected to close by the end of 2017, subject to certain regulatory and other approvals, and will include customary closing adjustments. An estimated gain of \$130 million (\$100 million after-tax) is expected to be recognized upon closing of the transaction.

At September 30, 2017, the related assets and liabilities were classified as held for sale in the Energy segment as follows:

(unaudited - millions of Canadian \$)	
<b>Assets held for sale</b>	
Accounts receivable	6
Inventories	1
Plant, property and equipment	424
<b>Total assets held for sale</b>	<b>431</b>
<b>Liabilities related to assets held for sale</b>	
Accounts payable and other	1
Other long-term liabilities	17
<b>Total liabilities related to assets held for sale</b>	<b>18</b>

**5. Income taxes**

The effective tax rates for the nine-month periods ended September 30, 2017 and 2016 were 24 per cent and 9 per cent, respectively. The higher effective tax rate in 2017 was primarily the result of changes in the proportion of income earned between Canadian and foreign jurisdictions and the goodwill impairment charge in 2016.

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## 6. Long-term debt

### LONG-TERM DEBT ISSUED

The Company issued long-term debt in the nine months ended September 30, 2017 as follows:

(unaudited - millions of Canadian \$, unless noted otherwise)					
Company	Issue date	Type	Maturity date	Amount	Interest rate
<b>TRANSCANADA PIPELINES LIMITED</b>					
	September 2017	Medium Term Notes	March 2028	300	3.39%
	September 2017	Medium Term Notes	September 2047	700	4.33%
<b>TUSCARORA GAS TRANSMISSION COMPANY</b>					
	August 2017	Term Loan	August 2020	US 25	Floating
<b>TC PIPELINES, LP</b>					
	May 2017	Senior Unsecured Notes	May 2027	US 500	3.90%

### LONG-TERM DEBT RETIRED

The Company retired long-term debt in the nine months ended September 30, 2017 as follows:

(unaudited - millions of Canadian \$, unless noted otherwise)					
Company	Retirement date	Type	Amount	Interest rate	
<b>TUSCARORA GAS TRANSMISSION COMPANY</b>					
	August 2017	Senior Secured Notes	US 12	3.82%	
<b>TRANSCANADA PIPELINES LIMITED</b>					
	June 2017	Acquisition Bridge Facility	US 1,513	Floating	
	February 2017	Acquisition Bridge Facility	US 500	Floating	
	January 2017	Medium Term Notes	300	5.10%	
<b>TRANSCANADA PIPELINE USA LTD.</b>					
	June 2017	Acquisition Bridge Facility	US 630	Floating	
	April 2017	Acquisition Bridge Facility	US 1,070	Floating	

The acquisition bridge facilities were put into place to finance a portion of the Columbia acquisition. Proceeds from the sale of the U.S. Northeast power assets were used to fully retire the remaining acquisition bridge facilities in second quarter 2017.

In the three and nine months ended September 30, 2017, TCPL capitalized interest related to capital projects of \$49 million and \$150 million (2016 - \$46 million and \$133 million).

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## 7. Junior subordinated notes issued

(unaudited - millions of Canadian \$, unless noted otherwise) Company	Issue date	Type	Maturity date	Amount	Interest rate
<b>TRANSCANADA PIPELINES LIMITED</b>					
	May 2017	Junior Subordinated Notes <sup>1,2</sup>	May 2077	1,500	4.90%
	March 2017	Junior Subordinated Notes <sup>1,2</sup>	March 2077	US 1,500	5.55%

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

<sup>2</sup> The Junior subordinated notes were issued to TransCanada Trust (the Trust), a financing trust subsidiary wholly-owned by TCPL. While the obligations of the Trust are fully and unconditionally guaranteed by TCPL on a subordinated basis, the Trust is not consolidated in TCPL's financial statements because TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are junior subordinated notes of TCPL.

In May 2017, the Trust issued \$1.5 billion of Trust Notes - Series 2017-B (Trust Notes) to third party investors with a fixed interest rate of 4.65 per cent for the first ten years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for \$1.5 billion of junior subordinated notes of TCPL at an initial fixed rate of 4.90 per cent, including a 0.25 per cent administration charge. The rate will reset commencing May 2027 until May 2047 to the then three month Bankers' Acceptance rate plus 3.33 per cent per annum; from May 2047 until May 2077, the interest rate will reset to the then three month Bankers' Acceptance rate plus 4.08 per cent per annum. The junior subordinated notes are callable at TCPL's option at any time on or after May 18, 2027 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

In March 2017, the Trust issued US\$1.5 billion of Trust Notes - Series 2017-A (Trust Notes) to third party investors with a fixed interest rate of 5.30 per cent for the first ten years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for US\$1.5 billion of junior subordinated notes of TCPL at an initial fixed rate of 5.55 per cent, including a 0.25 per cent administration charge. The rate will reset commencing March 2027 until March 2047 to the then three month LIBOR plus 3.458 per cent per annum; from March 2047 until March 2077, the interest rate will reset to the then three month LIBOR plus 4.208 per cent per annum. The junior subordinated notes are callable at TCPL's option at any time on or after March 15, 2027 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

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

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## 8. Common Shares

On January 31, 2017, the Company issued 3.0 million common shares to TransCanada for proceeds of \$187 million, on April 28, 2017, the Company issued 3.3 million common shares to TransCanada for proceeds of \$214 million and on July 31, 2017, the Company issued 3.0 million common shares to TransCanada for proceeds of \$190 million. These share issuances resulted in 868 million shares outstanding at September 30, 2017 (December 31, 2016 - 859 million).

## 9. Common units subject to rescission or redemption

### **Columbia Pipeline Partners LP acquisition**

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

At December 31, 2016, the entire \$1,073 million (US\$799 million) of the Company's non-controlling interest in CPPL was recorded as Common units subject to rescission or redemption on the condensed consolidated balance sheet.

### **Common units of TC PipeLines, LP subject to rescission**

In 2017, rescission rights on 1.6 million TC PipeLines, LP common units expired and \$106 million (US\$82 million) was reclassified to equity. At September 30, 2017, there were no outstanding Common units subject to rescission or redemption on the condensed consolidated balance sheet (December 31, 2016 - \$106 million (US\$82 million)).



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## 10. Other comprehensive (loss)/income and accumulated other comprehensive loss

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

<b>three months ended September 30, 2017</b>			
(unaudited - millions of Canadian \$)	<b>Before Tax Amount</b>	<b>Income Tax Recovery/Expense</b>	<b>Net of Tax Amount</b>
Foreign currency translation losses on net investment in foreign operations	(364)	(6)	(370)
Change in fair value of net investment hedges	(1)	—	(1)
Change in fair value of cash flow hedges	1	—	1
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	5	(3)	2
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	6	(2)	4
Other comprehensive income on equity investments	4	(1)	3
<b>Other comprehensive loss</b>	<b>(349)</b>	<b>(12)</b>	<b>(361)</b>

<b>three months ended September 30, 2016</b>			
(unaudited - millions of Canadian \$)	<b>Before Tax Amount</b>	<b>Income Tax Recovery/Expense</b>	<b>Net of Tax Amount</b>
Foreign currency translation gains on net investment in foreign operations	55	—	55
Change in fair value of net investment hedges	(2)	1	(1)
Change in fair value of cash flow hedges	6	(1)	5
Reclassification to net income of gains and losses on cash flow hedges	1	(1)	—
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	6	(2)	4
Other comprehensive income on equity investments	5	(1)	4
<b>Other comprehensive income</b>	<b>71</b>	<b>(4)</b>	<b>67</b>

<b>nine months ended September 30, 2017</b>			
(unaudited - millions of Canadian \$)	<b>Before Tax Amount</b>	<b>Income Tax Recovery/Expense</b>	<b>Net of Tax Amount</b>
Foreign currency translation losses on net investment in foreign operations	(717)	(4)	(721)
Reclassification of foreign currency translation gains on net investment on disposal of foreign operations	(77)	—	(77)
Change in fair value of net investment hedges	(4)	1	(3)
Change in fair value of cash flow hedges	5	(1)	4
Reclassification to net income of gains and losses on cash flow hedges	(2)	1	(1)
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	5	(3)	2
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	16	(5)	11
Other comprehensive income on equity investments	8	(2)	6
<b>Other comprehensive loss</b>	<b>(766)</b>	<b>(13)</b>	<b>(779)</b>

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<b>nine months ended September 30, 2016</b>	<b>Before Tax Amount</b>	<b>Income Tax Recovery/Expense</b>	<b>Net of Tax Amount</b>
(unaudited - millions of Canadian \$)			
Foreign currency translation losses on net investment in foreign operations	(150)	(2)	(152)
Change in fair value of net investment hedges	(12)	3	(9)
Change in fair value of cash flow hedges	33	(12)	21
Reclassification to net income of gains and losses on cash flow hedges	65	(25)	40
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	17	(5)	12
Other comprehensive income on equity investments	14	(3)	11
Other comprehensive loss	(33)	(44)	(77)

The changes in AOCI by component are as follows:

<b>three months ended September 30, 2017</b>	<b>Currency Translation Adjustments</b>	<b>Cash Flow Hedges</b>	<b>Pension and OPEB Plan Adjustments</b>	<b>Equity Investments</b>	<b>Total<sup>1</sup></b>
(unaudited - millions of Canadian \$)					
AOCI balance at July 1, 2017	<b>(716)</b>	<b>(27)</b>	<b>(201)</b>	<b>(345)</b>	<b>(1,289)</b>
Other comprehensive (loss)/income before reclassifications <sup>2,3</sup>	<b>(303)</b>	<b>2</b>	<b>2</b>	<b>—</b>	<b>(299)</b>
Amounts reclassified from accumulated other comprehensive loss	<b>—</b>	<b>—</b>	<b>4</b>	<b>3</b>	<b>7</b>
Net current period other comprehensive (loss)/income	<b>(303)</b>	<b>2</b>	<b>6</b>	<b>3</b>	<b>(292)</b>
<b>AOCI balance at September 30, 2017</b>	<b>(1,019)</b>	<b>(25)</b>	<b>(195)</b>	<b>(342)</b>	<b>(1,581)</b>

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

<sup>2</sup> Other comprehensive (loss)/income before reclassifications on currency translation adjustments and cash flow hedges is net of non-controlling interest losses of \$68 million and losses of \$1 million, respectively.

<sup>3</sup> Other comprehensive (loss)/income before reclassifications on pension and OPEB plan adjustments includes a \$27 million reduction on settlements and curtailments.

<b>nine months ended September 30, 2017</b>	<b>Currency Translation Adjustments</b>	<b>Cash Flow Hedges</b>	<b>Pension and OPEB Plan Adjustments</b>	<b>Equity Investments</b>	<b>Total<sup>1</sup></b>
(unaudited - millions of Canadian \$)					
AOCI balance at January 1, 2017	<b>(376)</b>	<b>(28)</b>	<b>(208)</b>	<b>(348)</b>	<b>(960)</b>
Other comprehensive (loss)/income before reclassifications <sup>2,3</sup>	<b>(566)</b>	<b>4</b>	<b>2</b>	<b>—</b>	<b>(560)</b>
Amounts reclassified from accumulated other comprehensive loss	<b>(77)</b>	<b>(1)</b>	<b>11</b>	<b>6</b>	<b>(61)</b>
Net current period other comprehensive (loss)/income <sup>4</sup>	<b>(643)</b>	<b>3</b>	<b>13</b>	<b>6</b>	<b>(621)</b>
<b>AOCI balance at September 30, 2017</b>	<b>(1,019)</b>	<b>(25)</b>	<b>(195)</b>	<b>(342)</b>	<b>(1,581)</b>

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

<sup>2</sup> Other comprehensive (loss)/income before reclassifications on currency translation adjustments net of non-controlling interest losses of \$158 million.

<sup>3</sup> Other comprehensive (loss)/income before reclassifications on pension and OPEB plan adjustments includes a \$27 million reduction on settlements and curtailments.

<sup>4</sup> Losses related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be \$10 million (\$7 million, net of tax) at September 30, 2017. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

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

	Amounts reclassified from accumulated other comprehensive loss <sup>1</sup>				Affected line item in the condensed consolidated statement of income
	three months ended September 30		nine months ended September 30		
(unaudited - millions of Canadian \$)	2017	2016	2017	2016	
Cash flow hedges					
Commodities	4	7	15	(54)	Revenues (Energy)
Foreign exchange	—	(5)	—	—	Interest income and other
Interest rate	(4)	(3)	(13)	(11)	Interest expense
	—	(1)	2	(65)	Total before tax
	—	1	(1)	25	Income tax expense
	—	—	1	(40)	Net of tax
Pension and other post-retirement benefit plan adjustments					
Amortization of actuarial loss	(4)	(6)	(12)	(17)	Plant operating costs and other <sup>2</sup>
Settlement charge	(2)	—	(2)	—	Plant operating costs and other <sup>2</sup>
	(6)	(6)	(14)	(17)	Total before tax
	2	2	5	5	Income tax expense
	(4)	(4)	(9)	(12)	Net of tax
Equity investments					
Equity income	(4)	(5)	(8)	(14)	Income from equity investments
	1	1	2	3	Income tax expense
	(3)	(4)	(6)	(11)	Net of tax
Currency translation adjustments					
Realization of foreign currency translation gain on disposal of foreign operations	—	—	77	—	(Loss)/Gain on sale of assets
	—	—	—	—	Income tax expense
	—	—	77	—	Net of tax

<sup>1</sup> All amounts in parentheses indicate expenses to the condensed consolidated statement of income.

<sup>2</sup> These accumulated other comprehensive loss components are included in the computation of net benefit cost. Refer to Note 11 for additional detail.

## 11. Employee post-retirement benefits

As a result of settlements and curtailments that occurred upon the completion of the U.S. Northeast power generation asset sales, remeasurements were performed in the third quarter on TCPL's U.S. defined benefit plan (DB plan) and other post-retirement benefit plans. The U.S. DB plan and other post-retirement benefit plan remeasurements used a weighted average discount rate of 4.10 per cent. All other assumptions were consistent with those employed at December 31, 2016. The impact of these remeasurements reduced the DB plan's unrealized actuarial losses by \$3 million, which was included in Other comprehensive income, and resulted in a settlement charge of \$2 million which was recorded in net benefit cost in third quarter 2017. These remeasurements had no impact on the other post-retirement benefit plan's unrealized actuarial losses.

In third quarter 2017, the year to date lump sum payouts exceeded service and interest costs for the Columbia's DB plan. As a result, remeasurements were performed on the Columbia DB plan using a discount rate of 3.70 per cent. All

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other assumptions were consistent with those employed at December 31, 2016. The remeasurement of the Columbia DB plan increased the Company's unrealized actuarial gains by \$16 million, of which \$14 million was recorded in Regulatory assets and \$2 million was recorded in Other comprehensive income.

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

(unaudited - millions of Canadian \$)	three months ended September 30				nine months ended September 30			
	Pension benefit plans		Other post-retirement benefit plans		Pension benefit plans		Other post-retirement benefit plans	
	2017	2016	2017	2016	2017	2016	2017	2016
Service cost	25	28	1	1	81	79	3	2
Interest cost	30	34	3	4	92	93	10	9
Expected return on plan assets	(45)	(48)	(5)	(5)	(134)	(127)	(16)	(6)
Amortization of actuarial loss	3	5	1	1	11	15	1	2
Amortization of regulatory asset	26	8	—	—	33	17	1	—
Amortization of transitional obligation related to regulated business	—	—	—	—	—	—	—	1
Settlement charge	2	—	—	—	2	—	—	—
<b>Net benefit cost recognized</b>	<b>41</b>	<b>27</b>	<b>—</b>	<b>1</b>	<b>85</b>	<b>77</b>	<b>(1)</b>	<b>8</b>

Effective April 1, 2017, the Company closed its U.S. DB plan to non-union new entrants. As of April 1, 2017, all non-union hires will participate in the existing defined contribution plan (DC plan). Non-union U.S. employees who currently participate in the DC plan will have one final election opportunity to become a member of the U.S. DB plan as of January 1, 2018.

## 12. Risk management and financial instruments

### RISK MANAGEMENT OVERVIEW

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

### COUNTERPARTY CREDIT RISK

TCPL's maximum counterparty credit exposure with respect to financial instruments at September 30, 2017, without taking into account security held, consisted of cash and cash equivalents, accounts receivable, available for sale assets, derivative assets, loans and advances receivable. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At September 30, 2017, there were no significant amounts past due or impaired, no significant credit risk concentration and no significant credit losses during the period.

### LOAN RECEIVABLE FROM AFFILIATE

TCPL holds a 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline. The Company accounts for the joint venture as an equity investment. On April 21, 2017, TCPL entered into a MXN\$13.6 billion unsecured revolving credit facility with the joint venture, which bears interest at a floating rate and matures in March 2022. At September 30, 2017, Intangible and other assets on the Company's condensed consolidated balance sheet included a \$578 million loan receivable from the Sur de Texas joint venture.

This loan receivable represents TCPL's proportionate share of the debt financing requirements related to the joint venture and is included in Contributions to equity investments on the Company's condensed consolidated statement of

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cash flows. Interest income and other included income of \$11 million and \$14 million for the three and nine months ended September 30, 2017. These amounts were offset by a corresponding expense recorded in Income from equity investments.

### NET INVESTMENT IN FOREIGN OPERATIONS

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

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

(unaudited - millions of Canadian \$, unless noted otherwise)	September 30, 2017		December 31, 2016	
	Fair value <sup>1</sup>	Notional or principal amount	Fair value <sup>1</sup>	Notional or principal amount
U.S. dollar cross-currency interest rate swaps (maturing 2017 to 2019) <sup>2</sup>	(222)	US 1,400	(425)	US 2,350
U.S. dollar foreign exchange forward contracts	—	—	(7)	US 150
	<b>(222)</b>	<b>US 1,400</b>	<b>(432)</b>	<b>US 2,500</b>

<sup>1</sup> Fair values equal carrying values.

<sup>2</sup> In the three and nine months ended September 30, 2017, Net income includes net realized gains of \$1 million and \$3 million, respectively, (2016 - gains of \$1 million and \$5 million, respectively) related to the interest component of cross-currency swap settlements which are reported within Interest expense.

The notional amounts and fair value of U.S. dollar-denominated debt designated as a net investment hedge were as follows:

(unaudited - millions of Canadian \$, unless noted otherwise)	September 30, 2017	December 31, 2016
Notional amount	<b>24,900 (US 19,900)</b>	26,600 (US 19,800)
Fair value	<b>28,300 (US 22,600)</b>	29,400 (US 21,900)

## FINANCIAL INSTRUMENTS

### Non-derivative financial instruments

#### Fair value of non-derivative financial instruments

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

Available for sale assets are recorded at fair value which is calculated using quoted market prices where available.

Certain non-derivative financial instruments included in cash and cash equivalents, accounts receivable, intangible and other assets, notes payable, accounts payable and other, due to affiliate, accrued interest and other long-term liabilities have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity and would also be classified in Level II of the fair value hierarchy.

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

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**Balance sheet presentation of non-derivative financial instruments**

The following table details the fair value of the Company's non-derivative financial instruments, excluding those where carrying amounts approximate fair value, which would be classified in Level II of the fair value hierarchy:

(unaudited - millions of Canadian \$)	September 30, 2017		December 31, 2016	
	Carrying amount	Fair value	Carrying amount	Fair value
Long-term debt including current portion <sup>1,2</sup>	(34,630)	(39,627)	(40,150)	(45,047)
Junior subordinated notes	(7,004)	(7,238)	(3,931)	(3,825)
	(41,634)	(46,865)	(44,081)	(48,872)

<sup>1</sup> Long-term debt is recorded at amortized cost except for US\$850 million (December 31, 2016 - US\$850 million) that is attributed to hedged risk and recorded at fair value.

<sup>2</sup> Net income for the three and nine months ended September 30, 2017 included unrealized gains of \$1 million and \$2 million, respectively, (2016 unrealized gains of \$7 million and losses of \$6 million, respectively) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US\$850 million of long-term debt at September 30, 2017 (December 31, 2016 - US\$850 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

**Available for sale assets summary**

The following tables summarize additional information about the Company's restricted investments that are classified as available for sale assets:

(unaudited - millions of Canadian \$)	September 30, 2017		December 31, 2016	
	LMCI restricted investments	Other restricted investments <sup>2</sup>	LMCI restricted investments	Other restricted investments <sup>2</sup>
Fair Values <sup>1</sup>				
Fixed income securities (maturing within 1 year)	—	25	—	19
Fixed income securities (maturing within 1-5 years)	—	97	—	117
Fixed income securities (maturing within 5-10 years)	24	—	9	—
Fixed income securities (maturing after 10 years)	679	—	513	—
	703	122	522	136

<sup>1</sup> Available for sale assets are recorded at fair value and included in Other current assets and Restricted investments on the condensed consolidated balance sheet.

<sup>2</sup> Other restricted investments have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

(unaudited - millions of Canadian \$)	September 30, 2017		September 30, 2016	
	LMCI restricted investments <sup>1</sup>	Other restricted investments <sup>2</sup>	LMCI restricted investments <sup>1</sup>	Other restricted investments <sup>2</sup>
Net unrealized (losses)/gains in the period				
three months ended	(38)	—	3	—
nine months ended	(23)	—	25	1
Net realized (losses)/gains in the period				
three months ended	—	—	1	—
nine months ended	(1)	—	1	—

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

<sup>2</sup> Unrealized gains and losses on other restricted investments are included in OCI.

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## Derivative instruments

### Fair value of derivative instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses period end market rates and applies a discounted cash flow valuation model. The fair value of commodity derivatives has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used. The fair value of options has been calculated using the Black-Scholes pricing model. Credit risk has been taken into consideration when calculating the fair value of derivative instruments.

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

### Balance sheet presentation of derivative instruments

The balance sheet classification of the fair value of the derivative instruments as at September 30, 2017 is as follows:

at September 30, 2017 (unaudited - millions of Canadian \$)	Cash Flow Hedges	Fair Value Hedges	Net Investment Hedges	Held for Trading	Total Fair Value of Derivative Instruments <sup>1</sup>
Other current assets					
Commodities <sup>2</sup>	4	—	—	196	200
Foreign exchange	—	—	2	81	83
Interest rate	2	—	—	1	3
	6	—	2	278	286
Intangible and other assets					
Commodities <sup>2</sup>	1	—	—	88	89
Foreign exchange	—	—	—	—	—
	1	—	—	88	89
<b>Total Derivative Assets</b>	<b>7</b>	<b>—</b>	<b>2</b>	<b>366</b>	<b>375</b>
Accounts payable and other					
Commodities <sup>2</sup>	(1)	—	—	(249)	(250)
Foreign exchange	—	—	(181)	(20)	(201)
Interest rate	—	(2)	—	—	(2)
	(1)	(2)	(181)	(269)	(453)
Other long-term liabilities					
Commodities <sup>2</sup>	(1)	—	—	(110)	(111)
Foreign exchange	—	—	(43)	—	(43)
Interest rate	—	(1)	—	—	(1)
	(1)	(1)	(43)	(110)	(155)
<b>Total Derivative Liabilities</b>	<b>(2)</b>	<b>(3)</b>	<b>(224)</b>	<b>(379)</b>	<b>(608)</b>
<b>Total Derivatives</b>	<b>5</b>	<b>(3)</b>	<b>(222)</b>	<b>(13)</b>	<b>(233)</b>

<sup>1</sup> Fair value equals carrying value.

<sup>2</sup> Includes purchases and sales of power, natural gas and liquids.

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The balance sheet classification of the fair value of the derivative instruments as at December 31, 2016 is as follows:

at December 31, 2016 (unaudited - millions of Canadian \$)	Cash Flow Hedges	Fair Value Hedges	Net Investment Hedges	Held for Trading	Total Fair Value of Derivative Instruments <sup>1</sup>
Other current assets					
Commodities <sup>2</sup>	6	—	—	351	357
Foreign exchange	—	—	6	10	16
Interest rate	1	1	—	1	3
	7	1	6	362	376
Intangible and other assets					
Commodities <sup>2</sup>	4	—	—	118	122
Foreign exchange	—	—	10	—	10
Interest rate	1	—	—	—	1
	5	—	10	118	133
<b>Total Derivative Assets</b>	12	1	16	480	509
Accounts payable and other					
Commodities <sup>2</sup>	—	—	—	(330)	(330)
Foreign exchange	—	—	(237)	(38)	(275)
Interest rate	(1)	(1)	—	—	(2)
	(1)	(1)	(237)	(368)	(607)
Other long-term liabilities					
Commodities <sup>2</sup>	—	—	—	(118)	(118)
Foreign exchange	—	—	(211)	—	(211)
Interest rate	—	(1)	—	—	(1)
	—	(1)	(211)	(118)	(330)
<b>Total Derivative Liabilities</b>	(1)	(2)	(448)	(486)	(937)
<b>Total Derivatives</b>	11	(1)	(432)	(6)	(428)

<sup>1</sup> Fair value equals carrying value.

<sup>2</sup> Includes purchases and sales of power, natural gas and liquids.

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



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**Notional and Maturity Summary**

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

<b>at September 30, 2017</b>					
(unaudited)	<b>Power</b>	<b>Natural Gas</b>	<b>Liquids</b>	<b>Foreign Exchange</b>	<b>Interest</b>
Purchases <sup>1</sup>	<b>83,491</b>	<b>159</b>	<b>8</b>	—	—
Sales <sup>1</sup>	<b>53,727</b>	<b>152</b>	<b>10</b>	—	—
Millions of U.S. dollars	—	—	—	<b>US 3,072</b>	<b>US 1,550</b>
Millions of Mexican pesos	—	—	—	<b>MXN 100</b>	—
Maturity dates	<b>2017-2022</b>	<b>2017-2020</b>	<b>2017</b>	<b>2017-2018</b>	<b>2017-2019</b>

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

<b>at December 31, 2016</b>					
(unaudited)	<b>Power</b>	<b>Natural Gas</b>	<b>Liquids</b>	<b>Foreign Exchange</b>	<b>Interest</b>
Purchases <sup>1</sup>	86,887	182	6	—	—
Sales <sup>1</sup>	58,561	147	6	—	—
Millions of U.S. dollars	—	—	—	US 2,394	US 1,550
Maturity dates	2017-2021	2017-2020	2017	2017	2017-2019

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

**Unrealized and Realized Gains/(Losses) on Derivative Instruments**

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

(unaudited - millions of Canadian \$)	<b>three months ended September 30</b>		<b>nine months ended September 30</b>	
	<b>2017</b>	<b>2016</b>	<b>2017</b>	<b>2016</b>
<b>Derivative instruments held for trading<sup>1</sup></b>				
Amount of unrealized gains/(losses) in the period				
Commodities <sup>2</sup>	<b>45</b>	(97)	<b>(102)</b>	23
Foreign exchange	<b>33</b>	—	<b>89</b>	47
Interest rate	<b>(1)</b>	—	<b>(1)</b>	—
Amount of realized (losses)/gains in the period				
Commodities	<b>(82)</b>	(23)	<b>(167)</b>	(165)
Foreign exchange	<b>19</b>	(5)	<b>10</b>	52
Interest rate	<b>1</b>	—	<b>1</b>	—
<b>Derivative instruments in hedging relationships</b>				
Amount of realized gains/(losses) in the period				
Commodities	<b>4</b>	(15)	<b>17</b>	(155)
Foreign exchange	—	5	<b>5</b>	(101)
Interest rate	—	1	<b>1</b>	4

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

<sup>2</sup> In the three and nine months ended September 30, 2017, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur (2016 - nil and a net loss of \$42 million, respectively).

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**Derivatives in cash flow hedging relationships**

The components of OCI (Note 10) related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests are as follows:

(unaudited - millions of Canadian \$, pre-tax)	three months ended September 30		nine months ended September 30	
	2017	2016	2017	2016
Change in fair value of derivative instruments recognized in OCI (effective portion) <sup>1</sup>				
Commodities	2	7	5	33
Foreign exchange	—	(5)	—	—
Interest rate	(1)	4	—	—
	1	6	5	33
Reclassification of (losses)/gains on derivative instruments from AOCI to net income (effective portion) <sup>1</sup>				
Commodities <sup>2</sup>	(4)	(7)	(15)	54
Foreign exchange <sup>3</sup>	—	5	—	—
Interest rate <sup>4</sup>	4	3	13	11
	—	1	(2)	65
Gains/(losses) on derivative instruments recognized in net income (ineffective portion)				
Commodities <sup>2</sup>	—	14	—	(1)
	—	14	—	(1)

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

<sup>2</sup> Reported within Revenues on the condensed consolidated statement of income.

<sup>3</sup> Reported within Interest income and other on the condensed consolidated statement of income.

<sup>4</sup> Reported within Interest expense on the condensed consolidated statement of income.

**Offsetting of derivative instruments**

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

at September 30, 2017 (unaudited - millions of Canadian \$)	Gross derivative instruments presented on the balance sheet	Amounts available for offset <sup>1</sup>	Net amounts
Derivative – Asset			
Commodities	289	(220)	69
Foreign exchange	83	(63)	20
Interest rate	3	(1)	2
Total	375	(284)	91
Derivative – Liability			
Commodities	(361)	220	(141)
Foreign exchange	(244)	63	(181)
Interest rate	(3)	1	(2)
Total	(608)	284	(324)

<sup>1</sup> Amounts available for offset do not include cash collateral pledged or received.

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The following table shows the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis as at December 31, 2016:

at December 31, 2016 (unaudited - millions of Canadian \$)	Gross derivative instruments presented on the balance sheet	Amounts available for offset <sup>1</sup>	Net amounts
Derivative - Asset			
Commodities	479	(362)	117
Foreign exchange	26	(26)	—
Interest rate	4	(1)	3
Total	509	(389)	120
Derivative - Liability			
Commodities	(448)	362	(86)
Foreign exchange	(486)	26	(460)
Interest rate	(3)	1	(2)
Total	(937)	389	(548)

<sup>1</sup> Amounts available for offset do not include cash collateral pledged or received.

With respect to the derivative instruments presented above as at September 30, 2017, the Company provided cash collateral of \$230 million (December 31, 2016 - \$305 million) and letters of credit of \$22 million (December 31, 2016 - \$27 million) to its counterparties. The Company held nil (December 31, 2016 - nil) in cash collateral and \$3 million (December 31, 2016 - \$3 million) in letters of credit from counterparties on asset exposures at September 30, 2017.

#### Credit risk related contingent features of derivative instruments

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade.

Based on contracts in place and market prices at September 30, 2017, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was \$11 million (December 31, 2016 - \$19 million), for which the Company had provided collateral in the normal course of business of nil (December 31, 2016 - nil). If the credit-risk-related contingent features in these agreements were triggered on September 30, 2017, the Company would have been required to provide additional collateral of \$11 million (December 31, 2016 - \$19 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

The Company has sufficient liquidity in the form of cash and undrawn committed revolving credit facilities to meet these contingent obligations should they arise.

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**FAIR VALUE HIERARCHY**

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based on a fair value hierarchy.

<b>Levels</b>	<b>How fair value has been determined</b>
Level I	Quoted prices in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date.
Level II	Valuation based on the extrapolation of inputs, other than quoted prices included within Level I, for which all significant inputs are observable directly or indirectly.  Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers.  This category includes interest rate and foreign exchange derivative assets and liabilities where fair value is determined using the income approach and commodity derivatives where fair value is determined using the market approach.  Transfers between Level I and Level II would occur when there is a change in market circumstances.
Level III	Valuation of assets and liabilities are measured using a market approach based on extrapolation of inputs that are unobservable or where observable data does not support a significant portion of the derivative's fair value. This category mainly includes long-dated commodity transactions in certain markets where liquidity is low and the Company uses the most observable inputs available or, if not available, long-term broker quotes to estimate the fair value for these transactions. Valuation of options is based on the Black-Scholes pricing model.  Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which significant inputs are considered to be observable. As contracts near maturity and observable market data become available, they are transferred out of Level III and into Level II.

The fair value of the Company's derivative assets and liabilities measured on a recurring basis, including both current and non-current portions for at September 30, 2017, are categorized as follows:

<b>at September 30, 2017</b> (unaudited - millions of Canadian \$)	<b>Quoted prices in active markets</b> (Level I) <sup>1</sup>	<b>Significant other observable inputs</b> (Level II) <sup>1</sup>	<b>Significant unobservable inputs</b> (Level III) <sup>1</sup>	<b>Total</b>
Derivative instrument assets:				
Commodities	30	240	19	289
Foreign exchange	—	83	—	83
Interest rate	—	3	—	3
Derivative instrument liabilities:				
Commodities	(36)	(304)	(21)	(361)
Foreign exchange	—	(244)	—	(244)
Interest rate	—	(3)	—	(3)
	(6)	(225)	(2)	(233)

<sup>1</sup> There were no transfers from Level I to Level II or from Level II to Level III for the nine months ended September 30, 2017.

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The fair value of the Company's derivative assets and liabilities measured on a recurring basis, including both current and non-current portions at December 31, 2016, were categorized as follows:

<b>at December 31, 2016</b> (unaudited - millions of Canadian \$)	<b>Quoted prices in active markets (Level I)<sup>1</sup></b>	<b>Significant other observable inputs (Level II)<sup>1</sup></b>	<b>Significant unobservable inputs (Level III)<sup>1</sup></b>	<b>Total</b>
Derivative instrument assets:				
Commodities	134	326	19	479
Foreign exchange	—	26	—	26
Interest rate	—	4	—	4
Derivative instrument liabilities:				
Commodities	(102)	(343)	(3)	(448)
Foreign exchange	—	(486)	—	(486)
Interest rate	—	(3)	—	(3)
	32	(476)	16	(428)

<sup>1</sup> There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2016.

The following table presents the net change in fair value of derivative assets and liabilities classified as Level III of the fair value hierarchy:

(unaudited - millions of Canadian \$)	<b>three months ended September 30</b>		<b>nine months ended September 30</b>	
	<b>2017</b>	<b>2016</b>	<b>2017</b>	<b>2016</b>
Balance at beginning of period	<b>9</b>	12	<b>16</b>	9
Total (losses)/gains included in net income	<b>(10)</b>	2	<b>(12)</b>	13
Settlements	<b>(1)</b>	1	<b>4</b>	(1)
Sales	—	—	<b>(5)</b>	(2)
Transfers out of Level III	—	(3)	<b>(5)</b>	(6)
Total losses included in OCI	—	—	—	(1)
Balance at end of period <sup>1</sup>	<b>(2)</b>	12	<b>(2)</b>	12

<sup>1</sup> For the three and nine months ended September 30, 2017, revenues include unrealized losses of \$10 million and \$14 million, respectively, attributed to derivatives in the Level III category that were still held at September 30, 2017 (2016 - gains of \$1 million and \$3 million, respectively).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a \$2 million decrease or \$1 million increase, respectively, in the fair value of outstanding derivative instruments included in Level III as at September 30, 2017.

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## 13. Acquisitions & Dispositions

### Mexico Natural Gas Pipelines

#### TransGas

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

### Canadian Natural Gas Pipelines

#### Prince Rupert Gas Transmission

In July 2017, the Company was notified that PNW LNG would not be proceeding with their proposed LNG project and that Progress Energy (Progress) would be terminating their agreement with TCPL for development of the PRGT project effective August 10, 2017. In accordance with the terms of the agreement, all project costs incurred to advance the project, including carrying charges, are fully recoverable upon termination. At September 30, 2017, the expected reimbursement of project costs, previously recorded in Intangibles and other assets on the Company's condensed consolidated balance sheet, was included in Accounts receivable. In October 2017, the Company received full payment of the \$0.6 billion reimbursement from Progress.

### U.S. Natural Gas Pipelines

#### Iroquois Gas Transmission System and Portland Natural Gas Transmission System

On June 1, 2017, TCPL completed the sale of its 49.34 per cent interest in Iroquois and its remaining 11.81 per cent interest in PNGTS to TC PipeLines LP, valued at US\$765 million. Proceeds were comprised of US\$597 million in cash and US\$168 million representing a proportionate share of Iroquois and PNGTS debt.

#### Columbia Pipeline Group

In second quarter 2017, the Company completed its procedures over measuring the volume of base gas acquired as part of the acquisition of Columbia. As a result, the Company decreased the fair value of base gas by \$116 million (US\$90 million). This impacted the purchase price equation by decreasing property, plant and equipment by \$116 million (US\$90 million), decreasing deferred tax liabilities by \$45 million (US\$35 million) and increasing goodwill by \$71 million (US\$55 million). This adjustment did not impact the Company's net income.

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## Energy

### U.S. Northeast Power Assets

On June 2, 2017, TCPL completed the sale of Ravenswood, Ironwood, Kibby Wind and Ocean State Power for proceeds of approximately US\$2.029 billion, subject to post-closing adjustments. In 2016, the Company recorded a loss of approximately \$829 million (\$863 million after tax) which included the impact of an estimated \$70 million of foreign currency translation gains. The Company recorded an additional loss on sale of \$226 million (\$183 million after tax) in the nine months ended September 30, 2017, of which \$7 million (\$7 million after tax) was recorded in the third quarter. The 2017 loss included \$2 million in foreign currency translation gains. These additional losses primarily related to adjustments to the purchase price and repair costs for an unplanned outage at Ravenswood prior to close. The actual foreign currency translation gains of \$72 million were reclassified from AOCI to Net income on closing of the transaction.

On April 19, 2017, the Company completed the sale of TC Hydro for gross proceeds of US\$1.07 billion, subject to post-closing adjustments. As a result, in the nine months ended September 30, 2017, the Company recorded a gain on sale of approximately \$715 million (\$440 million after tax) including the impact of an estimated \$5 million of foreign currency translation gains which were reclassified from AOCI to net income. The gain on sale included an adjustment of \$2 million (\$1 million after tax) that was recorded in the third quarter.

Gains and losses from these sales are included in (Loss)/gain on sale of assets in the condensed consolidated statement of income. The proceeds received from the sale of the U.S. Northeast Power assets were used to fully repay the outstanding balances on the Company's acquisition bridge facilities that partially funded the acquisition of Columbia.

## 14. Commitments, contingencies and guarantees

### COMMITMENTS

TCPL's operating lease commitments at December 31, 2016 included future payments related to our U.S. Northeast power assets. As a result of the completion of the thermal power asset sale on June 2, 2017, the remaining future obligations reported at December 31, 2016 have decreased by: \$2 million in 2017, \$52 million in 2018, \$34 million in 2019 and \$102 million in 2022 and beyond.

### CONTINGENCIES

TCPL and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

In March 2017, the U.S. Department of State issued a U.S. Presidential Permit authorizing construction of the U.S./Canada border crossing facilities of the Keystone XL pipeline. TCPL discontinued the claim under Chapter 11 of the North American Free Trade Agreement and has also withdrawn the U.S. Constitutional challenge.

### GUARANTEES

TCPL and its partner on the Sur de Texas pipeline, IEnova, have jointly guaranteed the obligations for construction services during the construction of the pipeline.

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

The Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities. Such agreements include guarantees and letters of

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credit which are primarily related to delivery of natural gas, construction services and the payment of liabilities. For certain of these entities, any payments made by TCPL under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

The carrying value of these guarantees has been included in other long-term liabilities. Information regarding the Company's guarantees is as follows:

(unaudited - millions of Canadian \$)	Term	at September 30, 2017		at December 31, 2016	
		Potential exposure <sup>1</sup>	Carrying value	Potential exposure <sup>1</sup>	Carrying value
Sur de Texas	ranging to 2020	397	4	805	53
Bruce Power	ranging to 2018	88	1	88	1
Other jointly owned entities	ranging to 2059	105	14	87	28
		590	19	980	82

<sup>1</sup> TCPL's share of the potential estimated current or contingent exposure.

## 15. Related Party Transactions

Related party transactions are conducted in the normal course of business and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Interest income and other included nil, in the three and nine months ended September 30, 2017, related to inter-affiliate lending to TransCanada (September 30, 2016 - \$5 million and \$16 million).

Interest expense included \$18 million and \$50 million of interest charges, in the three and nine months ended September 30, 2017, as a result of inter-affiliate borrowing (September 30, 2016 - \$16 million and \$22 million).

The following amounts are included in Due to affiliate:

(unaudited millions of Canadian \$)	Maturity Date	2017		2016	
		Outstanding at September 30	Effective Interest Rate	Outstanding at December 31	Effective Interest Rate
Credit Facility <sup>1</sup>	Demand	2,343	3.2%	2,358	2.7%

<sup>1</sup> TransCanada has an unsecured \$3.0 billion credit facility with TCPL. Interest on this facility is charged at prime rate per annum.

At September 30, 2017, accounts payable and other included \$3 million due to TransCanada (December 31, 2016 - \$19 million).

The Company made interest payments of \$17 million and \$49 million to TransCanada in the three and nine months ended September 30, 2017 (September 30, 2016 - \$14 million and \$20 million).



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## 16. Variable interest entities

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

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

### Consolidated VIEs

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

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

(unaudited - millions of Canadian \$)	September 30, 2017	December 31, 2016
<b>ASSETS</b>		
<b>Current Assets</b>		
Cash and cash equivalents	91	77
Accounts receivable	56	71
Inventories	22	25
Other	8	10
	177	183
<b>Plant, Property and Equipment</b>	<b>3,552</b>	3,685
<b>Equity Investments</b>	<b>923</b>	606
<b>Goodwill</b>	<b>489</b>	525
<b>Intangible and Other Assets</b>	<b>—</b>	1
	<b>5,141</b>	5,000
<b>LIABILITIES</b>		
<b>Current Liabilities</b>		
Accounts payable and other	80	80
Accrued interest	30	21
Current portion of long-term debt	87	76
	197	177
<b>Regulatory Liabilities</b>	<b>33</b>	34
<b>Other Long-Term Liabilities</b>	<b>3</b>	4
<b>Deferred Income Tax Liabilities</b>	<b>13</b>	7
<b>Long-Term Debt</b>	<b>3,349</b>	2,827
	<b>3,595</b>	3,049

THIRD QUARTER 2017

**Non-Consolidated VIEs**

The Company's non-consolidated VIEs consist of legal entities where the Company does not have the power to direct the activities that most significantly impact the economic performance of these entities or where this power is shared with third parties. The Company contributes capital to these VIEs and receives ownership interests that provide it with residual claims on assets after liabilities are paid.

The carrying value of these VIEs and the maximum exposure to loss as a result of the Company's involvement with these VIEs are as follows:

(unaudited - millions of Canadian \$)	<b>September 30, 2017</b>	<b>December 31, 2016</b>
<b>Balance sheet</b>		
Equity investments	<b>4,409</b>	4,964
<b>Off-balance sheet</b>		
Potential exposure to guarantees	<b>171</b>	163
<b>Maximum exposure to loss</b>	<b>4,580</b>	5,127

**17. Subsequent events****Energy East and Related Projects**

On October 5, 2017, the Company concluded a review process of the Energy East, Eastern Mainline and Upland projects and informed the NEB that it will not proceed with the projects. At September 30, 2017, approximately \$1.3 billion related to these projects, including AFUDC, was recorded in Intangible and other assets on the Company's condensed consolidated balance sheet. Due to the project's inability to reach a regulatory decision, no recoveries of costs from third parties are expected, and the Company will record an approximate \$1.0 billion after-tax non-cash impairment charge in fourth quarter 2017.

**Common Share Issuance**

On October 31, 2017, the Company issued 3.1 million common shares to TransCanada for proceeds of \$189 million.