

Quarterly report to shareholders

Second quarter 2017

Financial highlights

(unaudited - millions of \$, except per share amounts)	three months ended June 30		six months ended June 30	
	2017	2016	2017	2016
Income				
Revenues	3,217	2,751	6,608	5,254
Net income attributable to common shares	881	365	1,524	617
per common share - basic	\$1.01	\$0.52	\$1.76	\$0.88
- diluted	\$1.01	\$0.52	\$1.75	\$0.88
Comparable EBITDA ¹	1,830	1,369	3,807	2,871
Comparable earnings ¹	659	366	1,357	860
per common share ¹	\$0.76	\$0.52	\$1.56	\$1.22
Cash flows				
Net cash provided by operations	1,353	1,148	2,655	2,229
Comparable funds generated from operations ¹	1,408	1,056	2,916	2,305
Comparable distributable cash flow ¹	936	702	2,158	1,676
per common share ¹	\$1.08	\$1.00	\$2.49	\$2.38
Capital spending - capital expenditures	1,792	982	3,352	1,818
- projects in development	56	90	98	157
- contributions to equity investments	473	114	665	284
Acquisitions, net of cash acquired	—	4	—	999
Proceeds from sales of assets, net of transaction costs	4,147	—	4,147	6
Dividends declared				
Per common share	\$0.625	\$0.565	\$1.25	\$1.13
Basic common shares outstanding (millions)				
Average for the period	870	703	868	703
End of period	871	703	871	703

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

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Management's discussion and analysis

July 27, 2017

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TransCanada Corporation. It discusses our business, operations, financial position, risks and other factors for the three and six months ended June 30, 2017, and should be read with the accompanying unaudited condensed consolidated financial statements for the three and six months ended June 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 and generally include words like *anticipate, expect, believe, may, will, should, estimate* or other similar words.

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

- planned changes in our business
- our financial and operational performance, including the performance of our subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows and future financing options available to us
- expected dividend growth
- expected costs for planned projects, including projects under construction, permitting and in development
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes
- expected 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 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
- planned and unplanned outages and the use of our pipeline and energy assets

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- integrity and reliability of our assets
- access to capital markets
- anticipated construction costs, schedules and completion dates.

Risks and uncertainties

- our ability to realize the anticipated benefits from the acquisition of Columbia
- our ability to successfully implement our strategic initiatives
- whether our strategic initiatives 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 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 TransCanada in our annual information form and other disclosure documents, which are available on SEDAR (www.sedar.com).

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NON-GAAP MEASURES

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

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

These measures do not have any standardized meaning as prescribed by U.S. 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 not to adjust for a specific item is subjective and made after careful consideration. Specific items may include:

- certain fair value adjustments relating to risk management activities
- income tax refunds and adjustments and changes to enacted tax rates
- gains or losses on sales of assets
- 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 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.

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

Comparable earnings and comparable earnings per share

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

We believe comparable distributable cash flow is a useful supplemental measure of performance that defines cash available to common shareholders before capital allocation. Comparable distributable cash flow is defined as comparable funds generated from operations less preferred share dividends, distributions to non-controlling interests and maintenance capital expenditures. Maintenance capital expenditures are expenditures incurred to maintain our operating capacity, asset integrity and reliability, and include amounts attributable to our proportionate share of maintenance capital expenditures on our equity investments. 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 - second 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 \$, except per share amounts)	three months ended June 30		six months ended June 30	
	2017	2016	2017	2016
Canadian Natural Gas Pipelines	305	342	587	614
U.S. Natural Gas Pipelines	401	188	962	455
Mexico Natural Gas Pipelines	120	41	238	86
Liquids Pipelines	251	198	478	410
Energy	645	371	843	245
Corporate	(40)	(24)	(73)	(51)
Total segmented earnings	1,682	1,116	3,035	1,759
Interest expense	(524)	(514)	(1,024)	(934)
Allowance for funds used during construction	121	111	222	212
Interest income and other	89	6	109	106
Income before income taxes	1,368	719	2,342	1,143
Income tax expense	(393)	(274)	(593)	(344)
Net income	975	445	1,749	799
Net income attributable to non-controlling interests	(55)	(52)	(145)	(132)
Net income attributable to controlling interests	920	393	1,604	667
Preferred share dividends	(39)	(28)	(80)	(50)
Net income attributable to common shares	881	365	1,524	617
Net income per common share - basic	\$1.01	\$0.52	\$1.76	\$0.88
- diluted	\$1.01	\$0.52	\$1.75	\$0.88

Net income attributable to common shares increased by \$516 million and \$907 million or \$0.49 and \$0.88 per share for the three and six months ended June 30, 2017 compared to the same periods in 2016. Net income per common share in 2017 included the dilutive effect of issuing 161 million common shares in 2016.

The 2017 results included:

- a \$255 million after-tax net 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 in second quarter, an incremental loss of \$176 million after tax recorded in second quarter on the sale of the thermal and wind package and \$10 million year-to-date of after-tax disposition costs
- an after-tax charge of \$15 million in second quarter and \$39 million year-to-date for integration-related costs associated with the acquisition of Columbia
- an after-tax charge of \$4 million in second quarter and \$11 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 \$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
- a charge of \$113 million in second quarter and \$139 million year-to-date related to costs associated with the acquisition of Columbia. In second quarter, \$109 million related to the dividend equivalent payments on the subscription receipts issued as part of the permanent financing of the transaction, \$10 million (\$36 million year-to-date) related to acquisition costs and \$6 million related to interest earned on the subscription receipt funds held in escrow
- an after-tax charge of \$9 million in second quarter and \$15 million year-to-date 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 charge of \$10 million in second quarter 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
- 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 increased by \$293 million and \$497 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 as discussed below in the reconciliation of net income to comparable earnings.

RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS

(unaudited - millions of \$, except per share amounts)	three months ended June 30		six months ended June 30	
	2017	2016	2017	2016
Net income attributable to common shares	881	365	1,524	617
Specific items (net of tax):				
Net gain on sales of U.S. Northeast power assets	(265)	—	(255)	—
Integration and acquisition related costs – Columbia	15	113	39	139
Keystone XL asset costs	4	9	11	15
Keystone XL income tax recoveries	—	—	(7)	—
Alberta PPA terminations	—	—	—	176
Restructuring costs	—	10	—	10
TC Offshore loss on sale	—	—	—	3
Risk management activities ¹	24	(131)	45	(100)
Comparable earnings	659	366	1,357	860
Net income per common share	\$1.01	\$0.52	\$1.76	\$0.88
Specific items (net of tax):				
Net gain on sales of U.S. Northeast power assets	(0.30)	—	(0.29)	—
Integration and acquisition related costs – Columbia	0.02	0.16	0.04	0.20
Keystone XL asset costs	—	0.01	0.01	0.02
Keystone XL income tax recoveries	—	—	(0.01)	—
Alberta PPA terminations	—	—	—	0.25
Restructuring costs	—	0.01	—	0.01
Risk management activities	0.03	(0.18)	0.05	(0.14)
Comparable earnings per common share	\$0.76	\$0.52	\$1.56	\$1.22

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1 Risk management activities (unaudited - millions of \$)	three months ended June 30		six months ended June 30	
	2017	2016	2017	2016
Canadian Power	3	20	4	7
U.S. Power	(94)	204	(156)	89
Liquids marketing	4	4	4	2
Natural Gas Storage	(4)	—	1	5
Foreign exchange	41	(4)	56	49
Income tax attributable to risk management activities	26	(93)	46	(52)
Total unrealized (losses)/gains from risk management activities	(24)	131	(45)	100

Comparable earnings increased by \$293 million or \$0.24 per share for the three months ended June 30, 2017 compared to the same period in 2016. This was primarily the net effect of:

- higher contribution from U.S. Natural Gas Pipelines due to incremental earnings from Columbia following the July 1, 2016 acquisition and higher ANR transportation revenues resulting from a FERC-approved rate settlement effective August 1, 2016
- higher earnings from Bruce Power mainly due to higher volumes resulting from fewer planned outage days
- higher interest expense mainly as a result of debt assumed in the acquisition of Columbia on July 1, 2016 and long-term debt issuances
- higher contribution from Mexico Natural Gas Pipelines due to earnings from Topolobampo beginning in July 2016 and Mazatlán beginning in December 2016
- higher earnings from Liquids Pipelines mainly due to higher volumes.

Comparable earnings increased by \$497 million or \$0.34 per share for the six months ended June 30, 2017 compared to the same period in 2016. This was primarily the net effect of:

- higher contribution from U.S. Natural Gas Pipelines due to incremental earnings from Columbia following the July 1, 2016 acquisition and higher ANR transportation revenues resulting from a FERC-approved rate settlement effective August 1, 2016
- higher interest expense as a result of debt assumed in the acquisition of Columbia on July 1, 2016 and long-term debt issuances
- higher contribution from Mexico Natural Gas Pipelines due to earnings from Topolobampo beginning in July 2016 and Mazatlán beginning in December 2016
- higher earnings from Bruce Power mainly due to higher volumes resulting from fewer planned outage days partially offset by higher interest expense
- higher earnings from Liquids Pipelines mainly due to higher volumes
- higher earnings from Western Power following the termination of the Alberta PPAs in March 2016.

Comparable earnings per share in 2017 included the dilutive effect of issuing 161 million common shares in 2016.

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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 \$43 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

at June 30, 2017			
(unaudited - billions of \$)	Expected in-service date	Estimated project cost	Carrying value
Canadian Natural Gas Pipelines			
Canadian Mainline	2017-2019	0.5	0.2
NGTL System ¹	2017	2.3	1.2
	2018	0.3	—
	2019	2.2	0.3
	2020	1.9	0.1
	2021+	0.4	—
U.S. Natural Gas Pipelines			
Columbia Gas			
Leach XPress	2017	US 1.5	US 0.9
Modernization I	2017	US 0.2	US 0.1
WB XPress	2018	US 0.8	US 0.3
Mountaineer XPress	2018	US 2.0	US 0.2
Modernization II	2018-2020	US 1.1	—
Columbia Gulf			
Rayne XPress	2017	US 0.4	US 0.3
Cameron Access	2018	US 0.3	US 0.2
Gulf XPress	2018	US 0.6	US 0.1
Midstream – Gibraltar	2017	US 0.3	US 0.2
Mexico Natural Gas Pipelines			
Tula	2018	US 0.6	US 0.4
Villa de Reyes	2018	US 0.6	US 0.3
Sur de Texas ²	2018	US 1.3	US 0.4
Liquids Pipelines			
Grand Rapids ²	2017	0.9	0.8
Northern Courier	2017	1.0	1.0
White Spruce	2018	0.2	—
Energy			
Napanee	2018	1.1	0.8
Bruce Power – life extension ³	up to 2020+	1.0	0.2
		21.5	8.0
Foreign exchange impact on near-term projects ⁴		2.9	1.0
Total near-term projects (billions of Cdn\$)		24.4	9.0

¹ As of June 30, 2017, near-term NGTL System capital projects are being reported by expected in-service dates.

² Our proportionate share.

³ 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.

⁴ Reflects U.S./Canada foreign exchange rate of \$1.30 at June 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 sponsor FID and/or complex regulatory processes.

at June 30, 2017			
(unaudited - billions of \$)	Segment	Estimated project cost	Carrying value
Heartland and TC Terminals	Liquids Pipelines	0.9	0.1
Upland	Liquids Pipelines	US 0.6	—
Grand Rapids Phase 2 ¹	Liquids Pipelines	0.7	—
Bruce Power - life extension ¹	Energy	5.3	—
Keystone projects			
Keystone XL ²	Liquids Pipelines	US 8.0	US 0.3
Keystone Hardisty Terminal ²	Liquids Pipelines	0.3	0.1
Energy East projects			
Energy East ³	Liquids Pipelines	15.7	0.8
Eastern Mainline	Canadian Natural Gas Pipelines	2.0	0.1
BC west coast LNG-related projects			
Coastal GasLink	Canadian Natural Gas Pipelines	4.8	0.4
NGTL System - Merrick	Canadian Natural Gas Pipelines	1.9	—
		40.2	1.8
Foreign exchange impact on medium to longer-term projects ⁴		2.6	0.1
Total medium to longer-term projects (billions of Cdn\$)		42.8	1.9

¹ Our proportionate share.

² Carrying value reflects amount remaining after impairment charge recorded in fourth quarter 2015.

³ Excludes transfer of Canadian Mainline natural gas assets.

⁴ Reflects U.S./Canada foreign exchange rate of \$1.30 at June 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, including from the U.S. Northeast power business in first half 2017, as detailed in the 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, remain 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 June 30		six months ended June 30	
	2017	2016	2017	2016
NGTL System	236	241	466	467
Canadian Mainline	264	291	511	522
Other Canadian pipelines ¹	28	30	56	62
Business development	(1)	(1)	(2)	(2)
Comparable EBITDA	527	561	1,031	1,049
Depreciation and amortization	(222)	(219)	(444)	(435)
Comparable EBIT and segmented earnings	305	342	587	614

¹ 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 \$37 million and \$27 million for the three and six months ended June 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 June 30		six months ended June 30	
	2017	2016	2017	2016
NGTL System	87	79	169	152
Canadian Mainline	48	52	100	102

Net income for the NGTL System increased by \$8 million and \$17 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 mainly due to a higher average investment base and higher OM&A incentive earnings 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 \$4 million and \$2 million for the three and six months ended June 30, 2017 compared to the same periods 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 us.

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DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by \$3 million and by \$9 million for the three and six months ended June 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

six months ended June 30 (unaudited)	NGTL System¹		Canadian Mainline²	
	2017	2016	2017	2016
Average investment base (millions of \$)	8,043	7,357	4,131	4,398
Delivery volumes (Bcf):				
Total	2,044	1,994	903	849
Average per day	11.3	11.0	5.0	4.7

¹ Field receipt volumes for the NGTL System for the six months ended June 30, 2017 were 2,070 Bcf (2016 – 2,075 Bcf). Average per day was 11.4 Bcf (2016 – 11.4 Bcf).

² 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 six months ended June 30, 2017 were 474 Bcf (2016 – 530 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 June 30		six months ended June 30	
	2017	2016	2017	2016
Columbia Gas ¹	136	—	321	—
ANR	93	70	215	157
TC PipeLines, LP ^{2,3}	26	27	58	58
Great Lakes ⁴	13	12	40	37
Midstream ¹	20	—	43	—
Columbia Gulf ¹	21	—	39	—
Other U.S. pipelines ^{1,2,3,5}	26	10	55	24
Non-controlling interests ⁶	75	75	183	170
Business development	—	—	(1)	(1)
Comparable EBITDA	410	194	953	445
Depreciation and amortization	(112)	(49)	(224)	(100)
Comparable EBIT	298	145	729	345
Foreign exchange impact	103	43	243	114
Comparable EBIT (Cdn\$)	401	188	972	459
Specific items:				
Integration and acquisition related costs – Columbia	—	—	(10)	—
TC Offshore loss on sale	—	—	—	(4)
Segmented earnings (Cdn\$)	401	188	962	455

¹ 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.

² 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 TransCanada's 49.34 per cent interest in Iroquois and its remaining 11.81 per cent interest in PNGTS on June 1, 2017.

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

	Effective ownership percentage as of	
	June 30, 2017	June 30, 2016
TC PipeLines, LP	26.3	27.4
Effective ownership through TC PipeLines, LP:		
Great Lakes	12.2	12.7
PNGTS	16.2	13.7

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

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

⁶ 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.

SECOND QUARTER 2017

U.S. Natural Gas Pipelines segmented earnings increased by \$213 million and \$507 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 primarily due to the acquisition of Columbia. Segmented earnings for the six months ended June 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 six months ended June 30, 2016 included a \$4 million pre-tax loss (\$3 million after tax) 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 stronger U.S. dollar had a positive 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 increased by US\$216 million and US\$508 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 and was the net effect of:

- US\$193 million and US\$443 million of EBITDA for the three and six months ended June 30, 2017 as a result of the acquisition of Columbia on July 1, 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\$63 million and US\$124 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 mainly due to the acquisition of Columbia and higher depreciation rates on ANR resulting from a 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.

SECOND 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 June 30		six months ended June 30	
	2017	2016	2017	2016
Topolobampo	40	—	80	(1)
Tamazunchale	27	28	56	55
Guadalajara	17	15	34	32
Mazatlán	17	—	33	—
Sur de Texas ¹	7	—	11	—
Other	—	1	—	—
Business development	—	(2)	—	(5)
Comparable EBITDA	108	42	214	81
Depreciation and amortization	(19)	(7)	(36)	(13)
Comparable EBIT	89	35	178	68
Foreign exchange impact	31	6	60	18
Comparable EBIT and segmented earnings (Cdn\$)	120	41	238	86

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

Mexico Natural Gas Pipelines segmented earnings increased by \$79 million and \$152 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 and are equivalent to comparable EBIT. A stronger U.S. dollar had a positive 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\$66 million and US\$133 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 and was the net effect of:

- incremental earnings from Topolobampo. 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 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.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US\$12 million and US\$23 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 primarily due to the commencement of depreciation on Topolobampo and Mazatlán.

SECOND 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 June 30		six months ended June 30	
	2017	2016	2017	2016
Keystone Pipeline System	329	274	635	576
Business development and other	3	2	9	(4)
Comparable EBITDA	332	276	644	572
Depreciation and amortization	(80)	(69)	(157)	(141)
Comparable EBIT	252	207	487	431
Specific items:				
Keystone XL asset costs	(5)	(13)	(13)	(23)
Risk management activities	4	4	4	2
Segmented earnings	251	198	478	410
Comparable EBIT denominated as follows:				
Canadian dollars	57	56	112	109
U.S. dollars	146	116	281	243
Foreign exchange impact	49	35	94	79
	252	207	487	431

Liquids Pipelines segmented earnings increased by \$53 million and \$68 million for the three and six months ended June 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 gains 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 \$56 million and \$72 million for the three and six months ended June 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
- increased business development activities, including advancement of Keystone XL
- a stronger U.S. dollar which had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by \$11 million and \$16 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 as a result of new facilities being placed in service and the effect of a stronger U.S. dollar.

SECOND 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 June 30		six months ended June 30	
	2017	2016	2017	2016
Canadian Power				
Western Power ¹	23	18	53	22
Eastern Power	83	84	177	186
Bruce Power	132	20	223	134
Canadian Power - comparable EBITDA^{1,2}	238	122	453	342
Depreciation and amortization	(36)	(36)	(73)	(83)
Canadian Power - comparable EBIT^{1,2}	202	86	380	259
U.S. Power (US\$)				
U.S. Power - comparable EBITDA	32	82	86	157
Depreciation and amortization ³	—	(33)	—	(64)
U.S. Power - comparable EBIT	32	49	86	93
Foreign exchange impact	9	11	27	28
U.S. Power - comparable EBIT (Cdn\$)	41	60	113	121
Natural Gas Storage and other - comparable EBITDA	11	9	32	18
Depreciation and amortization	(3)	(3)	(6)	(6)
Natural Gas Storage and other - comparable EBIT	8	6	26	12
Business Development comparable EBITDA and EBIT	(3)	(5)	(6)	(8)
Energy - comparable EBIT^{1,2}	248	147	513	384
Specific items:				
Net gain on sales of U.S. Northeast power assets	492	—	481	—
Alberta PPA terminations	—	—	—	(240)
Risk management activities	(95)	224	(151)	101
Segmented earnings^{1,2}	645	371	843	245

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

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

³ U.S. Northeast power assets no longer depreciated effective November 2016 when classified as held for sale.

SECOND QUARTER 2017

Energy segmented earnings increased by \$274 million and \$598 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 and included the following specific items:

- in 2017, a net gain of \$481 million before tax related to the monetization of our U.S. Northeast power business which included a \$717 million gain on the sale of TC Hydro, a loss of \$219 million on the sale of the thermal and wind package and \$17 million of pre-tax disposition costs. See Recent developments section for more details
- 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 June 30		six months ended June 30	
	2017	2016	2017	2016
Canadian Power	3	20	4	7
U.S. Power	(94)	204	(156)	89
Natural Gas Storage	(4)	—	1	5
Total unrealized (losses)/gains from risk management activities	(95)	224	(151)	101

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.

SECOND 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 June 30		six months ended June 30	
	2017	2016	2017	2016
Revenues¹				
Western Power	43	36	89	124
Eastern Power	93	108	198	203
Other ²	5	—	20	29
	141	144	307	356
Income from equity investments	7	7	15	7
Commodity purchases resold	(1)	—	(2)	(59)
Plant operating costs and other	(41)	(49)	(90)	(96)
Comparable EBITDA³	106	102	230	208
Depreciation and amortization	(36)	(36)	(73)	(83)
Comparable EBIT³	70	66	157	125
Breakdown of comparable EBITDA				
Western Power ³	23	18	53	22
Eastern Power	83	84	177	186
Comparable EBITDA³	106	102	230	208
Plant availability⁴				
Western Power ⁵	95%	83%	97%	91%
Eastern Power	93%	97%	96%	92%

¹ 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.

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

³ Included Alberta PPAs up to March 7, 2016 when the PPAs were terminated.

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

⁵ Plant availability was higher in the three and six months ended June 30, 2017 than the same periods in 2016 due to an unplanned outage at the Mackay River facility as a result of the Northern Alberta wildfires in 2016.

Western Power

Comparable EBITDA for Western Power increased by \$5 million and \$31 million for the three and six months ended June 30, 2017 compared to the same periods 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.

Depreciation and amortization decreased by \$10 million for the six months ended June 30, 2017 compared to the same period in 2016 following the termination of the Alberta PPAs.

Eastern Power

Comparable EBITDA for Eastern Power decreased by \$9 million for the six months ended June 30, 2017 compared to the same period in 2016 mainly due to lower earnings on the sale of unused natural gas transportation.

SECOND 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 June 30		six months ended June 30	
	2017	2016	2017	2016
Equity income included in comparable EBITDA and EBIT comprised of:				
Revenues	428	325	829	752
Operating expenses	(209)	(225)	(433)	(462)
Depreciation and other	(87)	(80)	(173)	(156)
Comparable EBITDA and EBIT¹	132	20	223	134
Bruce Power – other information				
Plant availability ²	92%	71%	91%	80%
Planned outage days	41	209	97	285
Unplanned outage days	3	4	20	12
Sales volumes (GWh) ¹	6,309	4,700	12,292	10,534
Realized sales price per MWh ³	\$68	\$69	\$67	\$67

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

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

³ Calculation based on actual and deemed generation. Realized sales 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 \$112 million and \$89 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 mainly due to higher volumes resulting from fewer planned outage days, partially offset by higher interest expense.

Planned outage work, which commenced on Unit 5 in February 2017, was completed in May 2017. Planned outages for Units 3 and 6 are scheduled to occur in second half of 2017. The overall average plant availability percentage in 2017 is expected to be approximately 90 per cent.

NATURAL GAS STORAGE AND OTHER

Comparable EBITDA for Natural Gas Storage and Other increased by \$2 million and \$14 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 mainly due to increased third party storage revenues as a result of higher realized natural gas storage price spreads.

SECOND QUARTER 2017

U.S. POWER

In second quarter 2017, we sold our U.S. Power generation assets and initiated the wind down of our TransCanada Power Marketing Ltd. (TCPM) operations. We expect to realize the value of the remaining TCPM marketing contracts and working capital over time. See Recent developments section for more details.

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

(unaudited - millions of US\$)	three months ended June 30		six months ended June 30	
	2017	2016	2017	2016
Revenue				
Power ¹	480	411	1,010	829
Capacity	41	77	83	139
	521	488	1,093	968
Commodity purchases resold	(407)	(289)	(816)	(594)
Plant operating costs and other ²	(82)	(117)	(191)	(217)
Comparable EBITDA³	32	82	86	157
Depreciation and amortization ⁴	—	(33)	—	(64)
Comparable EBIT	32	49	86	93

¹ Includes the realized gains and losses from financial derivatives used to manage U.S. Power's business which are presented on a net basis in Power revenues. The unrealized gains and losses from financial derivatives are excluded to arrive at comparable EBITDA.

² Includes the cost of fuel consumed in generation.

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

⁴ U.S. Northeast power assets no longer depreciated effective November 2016 when classified as held for sale.

Comparable EBITDA for U.S. Power decreased by US\$50 million and US\$71 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 mainly due to the sale of our generation assets in the second quarter 2017, partially offset by higher sales to customers in the PJM and New England wholesale markets.

SECOND 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 June 30		six months ended June 30	
	2017	2016	2017	2016
Comparable EBITDA and EBIT	(12)	—	(16)	(1)
Specific items:				
Integration and acquisition related costs – Columbia	(20)	(10)	(49)	(36)
Foreign exchange loss – inter-affiliate loan	(8)	—	(8)	—
Restructuring costs	—	(14)	—	(14)
Segmented losses	(40)	(24)	(73)	(51)

Corporate segmented losses increased by \$16 million and \$22 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 and included the following specific items that have been excluded from comparable EBIT:

- acquisition and integration costs associated with the acquisition of Columbia
- foreign exchange loss 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
- restructuring costs related to expected future losses under lease commitments.

OTHER INCOME STATEMENT ITEMS

Interest expense

(unaudited - millions of \$)	three months ended June 30		six months ended June 30	
	2017	2016	2017	2016
Interest on long-term debt and junior subordinated notes				
Canadian dollar-denominated	(118)	(110)	(226)	(221)
U.S. dollar-denominated	(323)	(250)	(640)	(496)
Foreign exchange impact	(111)	(73)	(214)	(158)
	(552)	(433)	(1,080)	(875)
Other interest and amortization expense	(28)	(18)	(45)	(37)
Capitalized interest	56	46	101	87
Interest expense included in comparable earnings	(524)	(405)	(1,024)	(825)
Specific item:				
Integration and acquisition related costs – Columbia	—	(109)	—	(109)
Interest expense	(524)	(514)	(1,024)	(934)

SECOND QUARTER 2017

Interest expense increased by \$10 million and \$90 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 and primarily reflects the net effect of:

- debt assumed in the acquisition of Columbia on July 1, 2016
- U.S. dollar-denominated long-term debt and junior subordinated notes issuances, including the impact of foreign exchange
- higher capitalized interest on Liquids and LNG projects and the Napanee power generating facility
- in 2016, the dividend equivalent payments on the subscription receipts issued to partially fund the Columbia acquisition.

Allowance for funds used during construction

(unaudited - millions of \$)	three months ended June 30		six months ended June 30	
	2017	2016	2017	2016
Canadian dollar-denominated	55	47	105	88
U.S. dollar-denominated	49	49	87	94
Foreign exchange impact	17	15	30	30
Allowance for funds used during construction	121	111	222	212

AFUDC increased \$10 million for both the three and six months ended June 30, 2017 compared to the same periods in 2016. The increase in Canadian dollar-denominated AFUDC is primarily due to increased investment in our NGTL System expansions, while the year-to-date decrease in U.S. dollar-denominated AFUDC is primarily due to the completed construction of the Topolobampo and Mazatlán pipelines, partially offset by increased investment in projects acquired as part of the Columbia acquisition on July 1, 2016.

Interest income and other

(unaudited - millions of \$)	three months ended June 30		six months ended June 30	
	2017	2016	2017	2016
Interest income and other included in comparable earnings	40	4	45	51
Specific items:				
Foreign exchange gain – inter-affiliate loan	8	—	8	—
Integration and acquisition related costs – Columbia	—	6	—	6
Risk management activities	41	(4)	56	49
Interest income and other	89	6	109	106

Interest income and other increased by \$83 million and \$3 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 and was primarily the net effect of:

- foreign exchange impact on the translation of foreign currency denominated working capital balances
- income of \$18 million related to Coastal GasLink project costs incurred to date. See Recent developments section for more information
- realized losses in 2017 compared to realized gains in 2016 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- foreign exchange gain on an inter-affiliate loan receivable from the Sur de Texas project which is offset in Corporate segmented losses
- in 2016, interest income on the gross proceeds of the subscription receipts held in escrow
- unrealized gains on risk management activities in 2017 compared to 2016. These amounts have been excluded from comparable earnings.

SECOND QUARTER 2017

Income tax expense

(unaudited - millions of \$)	three months ended June 30		six months ended June 30	
	2017	2016	2017	2016
Income tax expense included in comparable earnings	(198)	(189)	(442)	(369)
Specific items:				
Net gain on sales of U.S. Northeast power assets	(227)	—	(226)	—
Integration and acquisition related costs – Columbia	5	—	20	—
Keystone XL asset costs	1	4	2	8
Keystone XL income tax recoveries	—	—	7	—
Alberta PPA terminations	—	—	—	64
Restructuring costs	—	4	—	4
TC Offshore loss on sale	—	—	—	1
Risk management activities	26	(93)	46	(52)
Income tax expense	(393)	(274)	(593)	(344)

Income tax expense included in comparable earnings increased by \$9 million and \$73 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 mainly as a result of higher pre-tax earnings in 2017 compared to 2016 and changes in the proportion of income earned between Canadian and foreign jurisdictions.

Net income attributable to non-controlling interests

(unaudited - millions of \$)	three months ended June 30		six months ended June 30	
	2017	2016	2017	2016
Net income attributable to non-controlling interests	(55)	(52)	(145)	(132)

Net income attributable to non-controlling interests increased by \$13 million for the six months ended June 30, 2017 compared to the same period in 2016 primarily due to the acquisition of Columbia which included a non-controlling interest in CPPL. On February 17, 2017, we acquired all of the outstanding publicly held common units of CPPL.

Preferred share dividends

(unaudited - millions of \$)	three months ended June 30		six months ended June 30	
	2017	2016	2017	2016
Preferred share dividends	(39)	(28)	(80)	(50)

Preferred share dividends increased by \$11 million and \$30 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 primarily due to the issuance of Series 13 and Series 15 preferred shares in April 2016 and November 2016, respectively.

Recent developments

CANADIAN NATURAL GAS PIPELINES

NGTL System

On June 14, 2017, we announced an additional \$2 billion expansion program on our NGTL System based on new contracted customer demand for approximately 3 Bcf/d of incremental firm receipt and delivery services. We also successfully concluded a recent 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 381 MMcf/d of available expansion service was awarded under long-term contracts.

This additional expansion program increases our overall near-term capital program for completion to 2021 on the NGTL System to \$7.1 billion.

North Montney

On March 20, 2017, we filed an application with the NEB for a variance to the existing approvals for North Montney 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 of the sunset clause that was due to expire June 10, 2017 to March 31, 2018. In-service dates are planned for April 2019 and April 2020, subject to regulatory approval.

Towerbirch Expansion

On March 10, 2017, the Government of Canada approved the \$0.4 billion Towerbirch Expansion project. 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. In February 2017, the B.C. Government approved the environmental assessment with conditions that have since been met.

Canadian Mainline Tolling Option Open Season

On March 13, 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 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. The NEB is following a modified Streamlined Application Process with adjudication expected to follow after oral arguments are presented on September 11, 2017. The new service is requested to begin November 1, 2017.

Canadian Mainline 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 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 estimated \$160 million project. Once we have completed our tariff process for this capacity addition, an application to the NEB for approval to proceed with the project is planned for early 2018 to meet a November 1, 2019 in-service date.

SECOND QUARTER 2017

Coastal GasLink

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

Prince Rupert Gas Transmission

On July 25, 2017, we were notified that PNW LNG would not be proceeding with their proposed LNG project. As part of our PRGT agreement, following receipt of a termination notice, we would be reimbursed for the full costs and carrying charges incurred to advance the PRGT project. We expect to receive this payment later in 2017.

U.S. NATURAL GAS PIPELINES**Sale of Iroquois and PNGTS to TC PipeLines, LP**

On June 1, 2017, we closed the sale of a 49.34 per cent interest in Iroquois Gas Transmission System, LP (Iroquois) and our remaining 11.81 per cent interest in Portland Natural Gas Transmission System (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.

Leach XPress and Rayne XPress

FERC approvals and Notices to Proceed were received in first quarter 2017 for both the Leach XPress and Rayne XPress projects allowing construction activities to begin. The US\$1.5 billion Leach XPress project and the US\$0.4 billion Rayne XPress project are expected to be in service in November 2017.

Great Lakes Rate Case

Great Lakes is required to file a new Section 4 rate case with rates effective no later than January 1, 2018 as part of the settlement agreement with shippers approved November 2013. On March 31, 2017, Great Lakes submitted a General Section 4 Rate Filing and Tariff Changes with the FERC. The rates proposed in the filing will be effective on October 1, 2017, subject to refund, if alternate resolution to the proceeding is not reached prior to that date. Great Lakes has initiated customer discussions regarding the details of the filing and will seek to achieve a mutually beneficial resolution through settlement with its customers.

Columbia Pipeline Partners LP

On February 17, 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.

SECOND QUARTER 2017

LIQUIDS PIPELINES

Energy East

In January 2017, the NEB appointed three new panel members to undertake the review of the Energy East and Eastern Mainline projects. The new NEB panel members voided all decisions made by the previous hearing panel and will decide how to move forward with the hearing. We are not required to refile the application and parties will not be required to reapply for intervener status. All other proceedings and associated deadlines are no longer applicable. If the new panel members determine that the project application is complete, the 21-month NEB review period will commence.

On March 29, 2017, the NEB issued its decision to hear the Energy East and Eastern Mainline projects together. A hearing date has not yet been announced by the NEB.

On May 10, 2017, the NEB solicited comments on a draft list of issues for the Energy East and Eastern Mainline projects with comments due from the general public on May 31, 2017. Energy East and Eastern Mainline projects provided their comments on the draft list of issues on June 21, 2017. At the same time, we provided our response to the comments received by the NEB from the general public. We are awaiting the NEB's decision on the final list of issues. In addition, we are awaiting further direction from the NEB regarding the regulatory review process.

Keystone XL

In February 2017, we filed an application with the Nebraska Public Service Commission (PSC) seeking approval for the Keystone XL pipeline route through that state. A hearing on the application is scheduled in August 2017 and a final decision on the proposed route is expected by the end of November 2017.

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

On July 27, 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. The open season will close on September 28, 2017.

Grand Rapids

On June 1, 2017, the Grand Rapids pipeline, which will connect producing areas northwest of Fort McMurray, Alberta to terminals in the Edmonton/Heartland region, commenced line fill activities with anticipated in-service in third quarter 2017.

SECOND QUARTER 2017

ENERGY

U.S. Power

Monetization of U.S. Northeast power business

On April 19, 2017, we closed the sale of TC Hydro to Great River Hydro, LLC for US\$1.07 billion resulting in a gain of \$717 million (\$441 million after tax) recorded in second quarter 2017.

On June 2, 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 \$219 million (\$176 million after tax) was recorded in second quarter 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 TCPM operations and will realize the value of the remaining marketing contracts and working capital over time.

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 (including through our At-The-Market (ATM) equity issuance program), our Dividend Reinvestment Plan (DRP), 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 June 30, 2017, our current assets were \$4.9 billion and current liabilities were \$10.1 billion, leaving us with a working capital deficit of \$5.2 billion compared to a surplus of \$0.4 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
- approximately \$8.3 billion of unutilized, unsecured committed credit facilities.

CASH PROVIDED BY OPERATING ACTIVITIES

(unaudited - millions of \$, except per share amounts)	three months ended June 30		six months ended June 30	
	2017	2016	2017	2016
Net cash provided by operations	1,353	1,148	2,655	2,229
(Decrease)/increase in operating working capital	(17)	(218)	138	(86)
Funds generated from operations ¹	1,336	930	2,793	2,143
Specific items:				
Integration and acquisition related costs – Columbia	20	113	52	139
Keystone XL asset costs	5	13	13	23
U.S. Northeast power disposition costs	6	—	17	—
Current income taxes on sales of U.S. Northeast power assets	41	—	41	—
Comparable funds generated from operations¹	1,408	1,056	2,916	2,305
Dividends on preferred shares	(38)	(23)	(77)	(46)
Distributions paid to non-controlling interests	(69)	(62)	(149)	(124)
Maintenance capital expenditures including equity investments	(365)	(269)	(532)	(459)
Comparable distributable cash flow¹	936	702	2,158	1,676
Comparable distributable cash flow per common share¹	\$1.08	\$1.00	\$2.49	\$2.38

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

COMPARABLE FUNDS GENERATED FROM OPERATIONS

Comparable funds generated from operations increased \$352 million and \$611 million for the three and six months ended June 30, 2017 compared to the same periods in 2016 primarily due to the increase in comparable earnings.

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 increase from second quarter 2016 to 2017 was driven by an increase in comparable funds generated from operations partially offset by higher maintenance capital expenditures, distributions paid to non-controlling interests and dividends on preferred shares. Comparable distributable cash flow per share in 2017 includes the dilutive effect of issuing 161 million common shares in 2016.

SECOND QUARTER 2017

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 June 30		six months ended June 30	
	2017	2016	2017	2016
Canadian Natural Gas Pipelines	71	42	120	97
U.S. Natural Gas Pipelines	237	94	307	165
Other	57	133	105	197
Maintenance capital expenditures including equity investments	365	269	532	459

CASH PROVIDED BY/(USED IN) INVESTING ACTIVITIES

(unaudited - millions of \$)	three months ended June 30		six months ended June 30	
	2017	2016	2017	2016
Capital spending				
Capital expenditures	(1,792)	(982)	(3,352)	(1,818)
Capital projects in development	(56)	(90)	(98)	(157)
Contributions to equity investments	(473)	(114)	(665)	(284)
	(2,321)	(1,186)	(4,115)	(2,259)
Restricted cash	—	(13,113)	—	(13,113)
Acquisitions, net of cash acquired	—	(4)	—	(999)
Proceeds from sale of assets, net of transaction costs	4,147	—	4,147	6
Other distributions from equity investments	1	725	364	725
Deferred amounts and other	(169)	(20)	(254)	32
Net cash provided by/(used in) investing activities	1,658	(13,598)	142	(15,608)

Capital expenditures in 2017 were primarily related to:

- expansion of Columbia 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 relate to the Energy East and LNG pipeline projects.

Contributions to equity investments have increased in 2017 compared to 2016 primarily due to our investments in Sur de Texas and Bruce Power and 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 and included the proceeds from the sale of subscription receipts, net of dividend equivalent payments, and draws on the committed bridge loan credit facilities.

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

SECOND QUARTER 2017

The decrease in Other distributions from equity investments is primarily due to 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 (USED IN)/PROVIDED BY FINANCING ACTIVITIES

(unaudited - millions of \$)	three months ended June 30		six months ended June 30	
	2017	2016	2017	2016
Notes payable issued/(repaid), net	111	(853)	781	323
Long-term debt issued, net of issue costs	817	10,335	817	12,327
Long-term debt repaid	(4,418)	(933)	(5,469)	(2,290)
Junior subordinated notes issued, net of issue costs	1,489	—	3,471	—
Dividends and distributions paid	(435)	(482)	(854)	(932)
Common shares/subsidiary receipts issued, net of issue costs	18	4,371	36	4,374
Common shares repurchased	—	—	—	(14)
Partnership units of TC PipeLines, LP issued, net of issue costs	27	82	119	106
Common units of Columbia Pipeline Partners LP acquired	—	—	(1,205)	—
Preferred shares issued, net of issue costs	—	492	—	492
Net cash (used in)/provided by financing activities	(2,391)	13,012	(2,304)	14,386

LONG-TERM DEBT ISSUED

(unaudited - millions of \$) Company	Issue date	Type	Maturity date	Amount	Interest rate
TC PIPELINES, LP					
	May 2017	Senior Unsecured Notes	May 2027	US 500	3.90%

LONG-TERM DEBT RETIRED

(unaudited - millions of \$) Company	Retirement date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	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%
TRANSCANADA PIPELINE USA LTD.				
	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
TRANSCANADA PIPELINES LIMITED					
	May 2017	Junior Subordinated Notes ^{1,2}	May 2077	1,500	4.90%
	March 2017	Junior Subordinated Notes ^{1,2}	March 2077	US 1,500	5.55%

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

² The Junior subordinated notes were issued to TransCanada Trust (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 TransCanada'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 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 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 three month LIBOR plus 3.458 per cent per annum; from March 2047 until March 2077, the interest rate will reset to the 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.

DIVIDEND REINVESTMENT PLAN

Under our DRP, eligible holders of common and preferred shares of TransCanada can reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares. Common shares are issued from treasury at a discount of two per cent. For the dividends declared on May 5, 2017, approximately 35 per cent of common share dividends declared were designated to be reinvested by shareholders in TransCanada common shares under the DRP. Since issuance under the DRP from treasury at a discount began in July 2016, the cumulative participation rate has been approximately 38 per cent of common shares, resulting in \$773 million of common equity issued.

SECOND QUARTER 2017

TRANSCANADA CORPORATION ATM EQUITY ISSUANCE PROGRAM

In June 2017, we established an ATM program that allows us to issue common shares from treasury having an aggregate gross sales price of up to \$1.0 billion or their U.S. dollar equivalent, from time to time, at our discretion, at the prevailing market price when sold through the Toronto Stock Exchange or the New York Stock Exchange. The ATM program, which is effective for a 25-month period, will be activated at our discretion, if and as required, based on the spend profile of TransCanada's capital program and relative cost of other funding options. At June 30, 2017, no common shares were issued under the program.

TC PIPELINES, LP ATM EQUITY ISSUANCE PROGRAM

During first and second quarter 2017, 1.6 million common units were issued under the TC PipeLines, LP ATM program generating net proceeds of approximately US\$90 million. At June 30, 2017, our ownership interest in TC PipeLines, LP was 26.3 per cent as a result of issuances under the ATM program and resulting dilution.

In connection with the late filing of an employee-related Form 8-K with the SEC, in March 2016, TC PipeLines, LP became ineligible to use the then effective shelf registration statement upon the filing of its 2015 Annual Report. As a result, it was determined that the purchasers of the 1.6 million common units that were issued from March 8, 2016 to May 19, 2016 under the ATM program may have a rescission right for an amount equal to the purchase price paid for the units, plus statutory interest and less any distributions paid, upon the return of such units to TC PipeLines, LP. All rescission rights have expired and no unitholder claimed or attempted to exercise any rescission rights prior to the expiration date.

DIVIDENDS

On July 27, 2017, we declared quarterly dividends as follows:

Quarterly dividend on our common shares

\$0.625 per share

Payable on October 31, 2017 to shareholders of record at the close of business on September 29, 2017

Quarterly dividends on our preferred shares

Series 1	\$0.204125
Series 2	\$0.15432055
Series 3	\$0.1345
Series 4	\$0.11399178

Payable on September 29, 2017 to shareholders of record at the close of business on August 31, 2017

Series 5	\$0.14143750
Series 6	\$0.14007945
Series 7	\$0.25
Series 9	\$0.265625

Payable on October 30, 2017 to shareholders of record at the close of business on October 2, 2017

Series 11	\$0.2375
Series 13	\$0.34375
Series 15	\$0.30625

Payable on August 31, 2017 to shareholders of record at the close of business on August 11, 2017

SECOND QUARTER 2017

SHARE INFORMATION**as at July 24, 2017**

Common shares	Issued and outstanding	
	871 million	
Preferred shares	Issued and outstanding	Convertible to
Series 1	9.5 million	Series 2 preferred shares
Series 2	12.5 million	Series 1 preferred shares
Series 3	8.5 million	Series 4 preferred shares
Series 4	5.5 million	Series 3 preferred shares
Series 5	12.7 million	Series 6 preferred shares
Series 6	1.3 million	Series 5 preferred shares
Series 7	24 million	Series 8 preferred shares
Series 9	18 million	Series 10 preferred shares
Series 11	10 million	Series 12 preferred shares
Series 13	20 million	Series 14 preferred shares
Series 15	40 million	Series 16 preferred shares
Options to buy common shares	Outstanding	Exercisable
	11 million	7 million

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 July 27, 2017, we had a total of \$10.9 billion of committed revolving and demand credit facilities, including:

Amount	Unused capacity	Borrower	Description	Matures
\$3.0 billion	\$3.0 billion	TCPL	Committed, syndicated, revolving, extendible credit facility that supports TCPL's Canadian dollar commercial paper program and for general corporate purposes	December 2021
US\$2.0 billion	US\$2.0 billion	TCPL	Committed, syndicated, revolving, extendible credit facility that supports TCPL's U.S. dollar commercial paper program	December 2017
US\$1.0 billion	US\$0.8 billion	TCPL USA	Committed, syndicated, revolving, extendible credit facility that is used for TCPL USA general corporate purposes, guaranteed by TCPL	December 2017
US\$1.0 billion	US\$0.1 billion	Columbia	Committed, syndicated, revolving, extendible credit facility that is used for Columbia's general corporate purposes, guaranteed by TCPL	December 2017
US\$0.5 billion	US\$0.5 billion	TransCanada American Investments Ltd. (TAIL)	Committed, syndicated, revolving, extendible credit facility that supports TAIL's U.S. dollar commercial paper program, guaranteed by TCPL	December 2017
\$2.1 billion	\$0.8 billion	TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity	Demand

At July 27, 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.

SECOND QUARTER 2017

CONTRACTUAL OBLIGATIONS

Our capital commitments have decreased by approximately \$0.8 billion since December 31, 2016 primarily as a result of decreased commitments for the Sur de Texas and NGTL System natural gas pipelines due to the progression of construction. 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 thermal sale on June 2, 2017, the remaining future obligations included 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 second 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 TCPM 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 June 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.

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 for which we account as an equity investment. On April 21, 2017, we issued a peso-denominated unsecured revolving credit facility to the joint venture. This \$1 billion facility bears interest at a floating interest rate per annum. As at June 30, 2017, Intangible and other assets on our condensed consolidated balance sheet included a \$341 million loan receivable from the Sur de Texas joint venture (December 31, 2016 - nil). This loan receivable represents our proportionate share of our affiliate's debt financing requirements and is included in Contributions to equity investments on our condensed consolidated statement of cash flow. Interest income and other included \$3 million in the three and six months ended June 30, 2017 as a result of inter-affiliate lending to the Sur de Texas joint venture (2016 - nil and nil).

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

three months ended June 30, 2017	1.34
three months ended June 30, 2016	1.29
six months ended June 30, 2017	1.33
six months ended June 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 June 30		six months ended June 30	
	2017	2016	2017	2016
U.S. Natural Gas Pipelines comparable EBIT	298	145	729	345
Mexico Natural Gas Pipelines comparable EBIT	89	35	178	68
U.S. Liquids Pipelines comparable EBIT	146	116	281	243
U.S. Power comparable EBIT	32	49	86	93
AFUDC on U.S. dollar-denominated projects	49	49	87	94
Interest on U.S. dollar-denominated long-term debt	(323)	(250)	(640)	(496)
Capitalized interest on U.S. dollar-denominated capital expenditures	1	9	1	16
U.S. dollar non-controlling interests	(41)	(40)	(109)	(100)
	251	113	613	263

SECOND QUARTER 2017

Derivatives designated as a 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)	June 30, 2017		December 31, 2016	
	Fair value ¹	Notional or principal amount	Fair value ¹	Notional or principal amount
U.S. dollar cross-currency interest rate swaps (maturing 2017 to 2019) ²	(240)	US 1,500	(425)	US 2,350
U.S. dollar foreign exchange forward contracts	—	—	(7)	US 150
	(240)	US 1,500	(432)	US 2,500

¹ Fair values equal carrying values.

² In the three and six months ended June 30, 2017, net realized gains of \$1 million and \$2 million, respectively, (2016 - gains of \$2 million and \$4 million, respectively) related to the interest component of cross-currency swaps settlements are included in interest expense.

U.S. dollar-denominated debt designated as a net investment hedge

(unaudited - millions of Canadian \$, unless noted otherwise)	June 30, 2017	December 31, 2016
Notional amount	25,000 (US 19,300)	26,600 (US 19,800)
Fair value	28,500 (US 22,000)	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.

Balance sheet presentation of derivative instruments

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

(unaudited - millions of \$)	June 30, 2017	December 31, 2016
Other current assets	320	376
Intangible and other assets	126	133
Accounts payable and other	(532)	(607)
Other long-term liabilities	(248)	(330)
	(334)	(428)

SECOND QUARTER 2017

Unrealized and realized (losses)/gains 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 June 30		six months ended June 30	
	2017	2016	2017	2016
Derivative instruments held for trading¹				
Amount of unrealized (losses)/gains in the period				
Commodities ²	(91)	187	(147)	120
Foreign exchange	41	20	56	47
Interest rate	—	—	—	—
Amount of realized (losses)/gains in the period				
Commodities	(37)	(47)	(85)	(142)
Foreign exchange	(5)	13	(9)	57
Derivative instruments in hedging relationships				
Amount of realized gains/(losses) in the period				
Commodities	7	(67)	13	(140)
Foreign exchange	—	(43)	5	(106)
Interest rate	—	1	1	3

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

² Following the March 17, 2016 announcement of our intention to sell the U.S. Northeast power business, a loss of \$49 million and a gain of \$7 million were recorded in net income in the three months ended March 31, 2016 relating to discontinued cash flow hedges where it was probable that the anticipated underlying transaction would not occur as a result of a future sale.

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 June 30		six months ended June 30	
	2017	2016	2017	2016
Change in fair value of derivative instruments recognized in OCI (effective portion) ¹				
Commodities	(2)	42	3	26
Foreign exchange	—	40	—	5
Interest rate	—	(1)	1	(4)
	(2)	81	4	27
Reclassification of (losses)/gains on derivative instruments from AOCI to net income (effective portion) ¹				
Commodities ²	(7)	(21)	(11)	61
Foreign exchange ³	—	(39)	—	(5)
Interest rate ⁴	5	4	9	8
	(2)	(56)	(2)	64
Gains/(losses) on derivative instruments recognized in net income (ineffective portion)				
Commodities ²	—	43	—	(15)
	—	43	—	(15)

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

² Reported within revenues on the condensed consolidated statement of income.

³ Reported within interest income and other on the condensed consolidated statement of income.

⁴ 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 June 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 June 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.

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 June 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 17.4 per cent of our total assets as of June 30, 2017 and revenues attributable to Columbia for the six months ended June 30, 2017 represented approximately 15.1 per cent of our total revenues for that period.

Other than this system implementation, there were no changes in second 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 amount 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. You can find a summary of our critical accounting estimates in our 2016 Annual Report.

Our significant accounting policies have remained unchanged since December 31, 2016 other than described below. You can find a summary of our significant accounting policies 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.

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 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 five-step 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

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approach with a cumulative-effect adjustment as of the date of adoption. We currently anticipate adopting 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. While we have not identified any material differences in the amount and timing of revenue recognition for the operating segments that have been analyzed to date, the evaluation is not complete and we have not concluded on the overall impact of adopting the new guidance. We continue our contract analysis to obtain the information necessary to quantify the cumulative-effect adjustment, if any, on prior period revenues and revenue recognized going forward. We also 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.

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, however, early adoption is permitted.

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 are currently evaluating the impact of the adoption of this guidance, however, 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.

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Reconciliation of non-GAAP measures

(unaudited - millions of \$)	three months ended June 30		six months ended June 30	
	2017	2016	2017	2016
Comparable EBITDA				
Canadian Natural Gas Pipelines	527	561	1,031	1,049
U.S. Natural Gas Pipelines	551	252	1,271	590
Mexico Natural Gas Pipelines	145	49	285	102
Liquids Pipelines	332	276	644	572
Energy	287	231	592	559
Corporate	(12)	—	(16)	(1)
Comparable EBITDA	1,830	1,369	3,807	2,871
Depreciation and amortization	(516)	(444)	(1,026)	(898)
Comparable EBIT	1,314	925	2,781	1,973
Specific items:				
Net gain on sales of U.S. Northeast power assets	492	—	481	—
Integration and acquisition related costs – Columbia	(20)	(10)	(59)	(36)
Foreign exchange loss – inter-affiliate loan	(8)	—	(8)	—
Keystone XL asset costs	(5)	(13)	(13)	(23)
Alberta PPA terminations	—	—	—	(240)
Restructuring costs	—	(14)	—	(14)
TC Offshore loss on sale	—	—	—	(4)
Risk management activities ¹	(91)	228	(147)	103
Segmented earnings	1,682	1,116	3,035	1,759

¹ Risk management activities (unaudited - millions of \$)	three months ended June 30		six months ended June 30	
	2017	2016	2017	2016
Canadian Power	3	20	4	7
U.S. Power	(94)	204	(156)	89
Natural Gas Storage	(4)	—	1	5
Liquids marketing	4	4	4	2
Total unrealized (losses)/gains from risk management activities	(91)	228	(147)	103

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Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

(unaudited - millions of \$, except per share amounts)	2017			2016			2015	
	Second	First	Fourth	Third	Second	First	Fourth	Third
Revenues	3,217	3,391	3,619	3,632	2,751	2,503	2,851	2,944
Net income/(loss) attributable to common shares	881	643	(358)	(135)	365	252	(2,458)	402
Comparable earnings	659	698	626	622	366	494	453	440
Per share statistics								
Net income/(loss) per common share - basic and diluted	\$1.01	\$0.74	(\$0.43)	(\$0.17)	\$0.52	\$0.36	(\$3.47)	\$0.57
Comparable earnings per common share	\$0.76	\$0.81	\$0.75	\$0.78	\$0.52	\$0.70	\$0.64	\$0.62
Dividends declared per common share	\$0.625	\$0.625	\$0.565	\$0.565	\$0.565	\$0.565	\$0.52	\$0.52

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 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.

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.

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FACTORS AFFECTING FINANCIAL INFORMATION BY QUARTER

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

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

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 includes 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 the monetization
- an additional \$68 million after-tax loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the Alberta PPA terminations
- an after-tax charge of \$67 million for costs associated with the acquisition of Columbia which included a \$44 million deferred tax adjustment upon acquisition and \$23 million of retention, severance and integration costs
- an after-tax charge of \$18 million related to Keystone XL costs for the maintenance and liquidation of project assets which 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 form 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 \$113 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 expected to close 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 form 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.

In third quarter 2015, comparable earnings excluded a charge of \$6 million after-tax for severance costs as part of a restructuring initiative to maximize the effectiveness and efficiency of our existing operations.