TransCanada
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TransCanada Reports Strong Second Quarter 2017 Financial Results
Performance Highlights Diversified, Low Risk Business Strategy

CALGARY, Alberta – **July 28, 2017** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced net income attributable to common shares for second quarter 2017 of $881 million or $1.01 per share compared to net income of $365 million or $0.52 per share for the same period in 2016. Comparable earnings for second quarter 2017 were $659 million or $0.76 per share compared to $366 million or $0.52 per share for the same period in 2016. TransCanada's Board of Directors also declared a quarterly dividend of $0.625 per common share for the quarter ending September 30, 2017, equivalent to $2.50 per common share on an annualized basis.

"Our diversified portfolio of high-quality, low risk energy infrastructure assets continued to perform very well in the second quarter of 2017," said Russ Girling, TransCanada's president and chief executive officer. "Comparable earnings per share increased 46 per cent compared to second quarter 2016 primarily due to the Columbia acquisition in July 2016 and the realization of associated synergies, strong performance across our Natural Gas and Liquids Pipelines businesses and higher earnings from Bruce Power following a major planned outage in second quarter 2016. The growth in earnings was accompanied by a significant increase in net cash provided by operations which rose to $1.4 billion from $1.1 billion in the same period last year."

"In the quarter, we added $2 billion of additional expansion projects on the NGTL System and today announced a $0.2 billion expansion on the Canadian Mainline, highlighting the organic growth opportunities that continue to emanate from our broad, strategically located asset base. We are now advancing a $24 billion near-term capital program that is expected to generate significant growth in earnings and cash flow and support an expected annual dividend growth rate at the upper end of an eight to 10 per cent range through 2020," added Girling. "To date we have invested $9.0 billion in these projects and are well positioned to both execute and fund the remainder of the program over the next few years. In addition, we concluded the sale of our U.S. Northeast merchant generation facilities, with proceeds used to fully retire the Columbia acquisition bridge facilities. With those sales complete, over 95 per cent of our future EBITDA is expected to be derived from regulated or long-term contracted assets."

"We also continue to progress a number of additional medium to longer-term organic growth opportunities in our three core businesses of natural gas pipelines, liquids pipelines and energy in Canada, the United States and Mexico. Success in advancing Keystone XL or other growth initiatives, including the Bruce Power life extension, could further augment or extend the Company's dividend growth outlook," concluded Girling.

Highlights

(All financial figures are unaudited and in Canadian dollars unless noted otherwise)

- Second quarter 2017 financial results
  - Net income attributable to common shares of $881 million or $1.01 per share
  - Comparable earnings of $659 million or $0.76 per share
  - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.8 billion
  - Net cash provided by operations of $1.4 billion
  - Comparable funds generated from operations of $1.4 billion
  - Comparable distributable cash flow of $936 million or $1.08 per common share
- Declared a quarterly dividend of $0.625 per common share for the quarter ending September 30, 2017
- Announced $2 billion of additional expansions on the NGTL System to increase receipt and delivery capacity

- In April, closed the sale of TC Hydro for US$1.07 billion and in June completed the sale of Ravenswood, Ironwood, Ocean State Power and Kibby Wind for US$2.029 billion. The proceeds from the sales were used to fully retire the acquisition bridge facilities which partially financed the Columbia acquisition
- On June 1, sold a 49.34 per cent interest in Iroquois Gas Transmission System, LP (Iroquois), together with our remaining 11.81 per cent interest in Portland Natural Gas Transmission System (PNGTS), to our master limited partnership, TC PipeLines, LP for a value of US$765 million
- Raised US$500 million at TC PipeLines, LP from issuance of 10 year senior unsecured notes
- Raised $1.5 billion in gross proceeds through a Canadian offering of Junior Subordinated Notes maturing in 2077
- Established an At-The-Market (ATM) program that allows us to issue up to $1 billion in common shares from time to time over a 25-month period, at our discretion, at the prevailing market price when sold in Canada or the United States. The ATM program 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
- In July, launched an open season to solicit additional binding commitments from interested parties for transportation of crude oil on the Keystone Pipeline and for the Keystone XL Pipeline project from Hardisty, Alberta to markets in Cushing, Oklahoma and the U.S. Gulf Coast
- On July 25, 2017, we were notified that Pacific NorthWest (PNW) LNG would not be proceeding with their proposed LNG project. As part of our Prince Rupert Gas Transmission (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
- On July 28, announced a $0.2 billion expansion project on the Canadian Mainline in southern Ontario

Net income attributable to common shares increased by $516 million to $881 million or $1.01 per share for the three months ended June 30, 2017 compared to the same period last year. Net income per common share in 2017 includes the dilutive effect of issuing 161 million common shares in 2016. Second quarter 2017 results included a $265 million after-tax net gain on the monetization of the U.S. Northeast power assets which was comprised of a $441 million after-tax gain on the sale of TC Hydro and an incremental 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 and a $4 million after-tax charge related to the maintenance of Keystone XL assets. Second quarter 2016 included a charge of $113 million related to costs associated with the Columbia acquisition which were primarily related to the dividend equivalent payments on the subscription receipts issued as part of the permanent financing of the transaction, an after-tax $10 million restructuring charge related to expected future losses under lease commitments and $9 million after-tax related to Keystone XL maintenance and liquidation costs. All of these specific items as well as unrealized gains and losses from changes in risk management activities are excluded from comparable earnings.

Comparable earnings for second quarter 2017 were $659 million or $0.76 per share compared to $366 million or $0.52 per share for the same period in 2016, an increase of $293 million or $0.24 per share and includes the dilutive effect of issuing 161 million common shares in 2016. The increase in second quarter comparable earnings was primarily due to higher contributions from U.S. Natural Gas Pipelines reflecting incremental earnings from Columbia following the July 1, 2016 acquisition and higher ANR transportation revenues resulting from higher rates effective August 1, 2016, higher earnings from Bruce Power mainly due to higher volumes resulting from fewer planned outage days, a higher contribution from Mexican Natural Gas Pipelines due to earnings from the Mazatlán and Topolobampo pipelines and higher earnings from Liquids Pipelines mainly due to higher volumes. These increases were partially offset by higher interest expense mainly as a result of debt assumed in the acquisition of Columbia and long-term debt issuances.

Notable recent developments include:

Natural Gas Pipelines:

- *NGTL System*: In June, we announced an additional $2 billion expansion program, subject to regulatory approvals, supported by new contracted customer demand for approximately 3 Bcf/d of incremental firm receipt and delivery services. The expansion will also increase delivery capacity at the Alberta/British Columbia export delivery point by 381 MMcf/d to serve markets in the Pacific Northwest, California and Nevada. NGTL now has a $7.1 billion near-term capital program targeted for completion by 2021.

- *Canadian Mainline Tolling Option Open Season:* In April, an application was filed with the National Energy Board (NEB) for approval of the long-term fixed-price service from the Empress receipt point in Alberta to the Dawn hub in Southern Ontario. 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.
- *Coastal GasLink:* The continuing delay in the Final Investment Decision (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.
- *Sale of Iroquois and PNGTS to TC PipeLines, LP:* On June 1, 2017, we sold a 49.34 per cent interest in Iroquois, together with our remaining 11.81 per cent interest in PNGTS, to our master limited partnership, TC PipeLines, LP for a value of US$765 million.
- *Leach XPress and Rayne XPress:* We continue to advance construction on the US$1.5 billion Leach XPress and the US$0.4 billion Rayne XPress projects. Both projects are expected to enter service in November 2017.

Liquids Pipelines:

- *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:* In June, the Grand Rapids pipeline commenced line fill activities with anticipated in-service in third quarter 2017.

Energy:

- *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 completed the sale of Ravenswood, Ironwood, Ocean State Power and Kibby Wind to Helix Generation, LLC for US$2.029 billion. An additional loss 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 which 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. We also initiated the monetization of our TransCanada Power Marketing Ltd. (TCPM) operations and will realize the value of the remaining marketing contracts and working capital over time.

Corporate:

- *Common Share Dividend:* Our Board of Directors declared a quarterly dividend of $0.625 per share for the quarter ending September 30, 2017 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $2.50 per common share on an annualized basis.
- *Junior Subordinated Debt Issuance:* In May 2017, TransCanada Trust issued $1.5 billion of 60-year Junior Subordinated Notes in Canada 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. The notes are callable at par beginning ten years following their issuance. All of the proceeds of the issuance by the Trust were loaned to TransCanada PipeLines Limited (TCPL) in $1.5 billion of subordinated notes at a rate of 4.90 per cent which includes a 0.25 per cent administration charge.
- *Financing at TC PipeLines, LP:* In May 2017, TC PipeLines, LP raised US$500 million from issuance of 10-year senior unsecured notes bearing an interest rate of 3.90 per cent.
- *Dividend Reinvestment Plan (DRP):* Based on the most recent quarter, approximately 35 per cent of the common share dividends declared are being reinvested in TransCanada common shares through our DRP.
- *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.

Teleconference and Webcast:

We will hold a teleconference and webcast on Friday, July 28, 2017 to discuss our second quarter 2017 financial results. Russ Girling, TransCanada President and Chief Executive Officer, and Don Marchand, Executive Vice-President and Chief Financial Officer, along with other members of the TransCanada executive leadership team, will discuss the financial results and Company developments at 9 a.m. (MT) / 11 a.m. (ET).

Members of the investment community and other interested parties are invited to participate by calling 800.377.0758 or 416.340.2218 (Toronto area). Please dial in 10 minutes prior to the start of the call. No pass code is required. A live webcast of the teleconference will be available at www.transcanada.com.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (ET) on August 4, 2017. Please call 800.408.3053 or 905.694.9451 (Toronto area) and enter pass code 9154252.

The **unaudited interim condensed Consolidated Financial Statements and Management’s Discussion and Analysis (MD&A) are available under TransCanada's profile on SEDAR at** www.sedar.com**, with the U.S. Securities and Exchange Commission on EDGAR at** www.sec.gov/info/edgar.shtml **and on the TransCanada website at** www.transcanada.com**.**

With more than 65 years' experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and liquids pipelines, power generation and gas storage facilities. TransCanada operates a network of natural gas pipelines that extends more than 91,500 kilometres (56,900 miles), tapping into virtually all major gas supply basins in North America. TransCanada is the continent's largest provider of gas storage and related services with 653 billion cubic feet of storage capacity. A large independent power producer, TransCanada owns or has interests in approximately 6,200 megawatts of power generation in Canada and the United States. TransCanada is also the developer and operator of one of North America's leading liquids pipeline systems that extends over 4,300 kilometres (2,700 miles) connecting growing continental oil supplies to key markets and refineries. TransCanada's common shares trade on the Toronto and New York stock exchanges under the symbol TRP. Visit TransCanada.com and our blog to learn more, or connect with us on social media and 3BL Media.

Forward Looking Information

This release contains certain information that is forward-looking and is subject to important risks and uncertainties (such statements are usually accompanied by words such as "anticipate", "expect", "believe", "may", "will", "should", "estimate", "intend" or other similar words). Forward-looking statements in this document are intended to provide TransCanada security holders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future plans and financial outlook. All forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this news release, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to update or revise any forward-looking information except as required by law. For additional information on the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, refer to the Quarterly Report to Shareholders dated July 27, 2017 and 2016 Annual Report filed under TransCanada's profile on SEDAR at www.sedar.com and with the U.S. Securities and Exchange Commission at www.sec.gov.

Non-GAAP Measures

This news release contains references to non-GAAP measures, including comparable earnings, comparable EBITDA, comparable distributable cash flow, comparable funds generated from operations, comparable earnings per share and comparable distributable cash flow per share, that do not have any standardized meaning as prescribed by U.S. GAAP and therefore are unlikely to be comparable to similar measures presented by other companies. These non-GAAP measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable. For more information on non-GAAP measures, refer to TransCanada's Quarterly Report to Shareholders dated July 27, 2017.

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TransCanada Media Enquiries:
Mark Cooper/James Millar
403.920.7859 or 800.608.7859

TransCanada Investor & Analyst Enquiries:
David Moneta/Stuart Kampel
403.920.7911 or 800.361.6522

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.

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

- 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).

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.

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.

	three months ended June 30		six months ended June 30	
(unaudited - millions of $, except per share amounts)	**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.

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $, except per share amounts)	**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

1 Risk management activities	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**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.

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.

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.

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.

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**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.

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	**NGTL System**[1]		**Canadian Mainline**[2]	
(unaudited)	**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).

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.

	three months ended June 30		six months ended June 30	
(unaudited - millions of US$, unless otherwise noted)	**2017**	**2016**	**2017**	**2016**
Columbia Gas[1]	**136**	—	**321**	—
ANR	**93**	70	**215**	157
TC PipeLines, LP[2,3]	**26**	27	**58**	58
Great Lakes[4]	**13**	12	**40**	37
Midstream[1]	**20**	—	**43**	—
Columbia Gulf[1]	**21**	—	**39**	—
Other U.S. pipelines[1,2,3,5]	**26**	10	**55**	24
Non-controlling interests[6]	**75**	75	**183**	170
Business development	**—**	—	**(1)**	(1)
Comparable EBITDA	**410**	194	**953**	445
Depreciation and amortization	**(112)**	(49)	**(224)**	(100)
Comparable EBIT	**298**	145	**729**	345
Foreign exchange impact	**103**	43	**243**	114
Comparable EBIT (Cdn$)	**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.

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.

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.

	three months ended June 30		six months ended June 30	
(unaudited - millions of US$, unless otherwise noted)	**2017**	**2016**	**2017**	**2016**
Topolobampo	**40**	—	**80**	(1)
Tamazunchale	**27**	28	**56**	55
Guadalajara	**17**	15	**34**	32
Mazatlán	**17**	—	**33**	—
Sur de Texas[1]	**7**	—	**11**	—
Other	**—**	1	**—**	—
Business development	**—**	(2)	**—**	(5)
Comparable EBITDA	**108**	42	**214**	81
Depreciation and amortization	**(19)**	(7)	**(36)**	(13)
Comparable EBIT	**89**	35	**178**	68
Foreign exchange impact	**31**	6	**60**	18
Comparable EBIT and segmented earnings (Cdn$)	**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.

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.

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**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.

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.

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2017**	**2016**	**2017**	**2016**
Canadian Power				
Western Power[1]	**23**	18	**53**	22
Eastern Power	**83**	84	**177**	186
Bruce Power	**132**	20	**223**	134
Canadian Power - comparable EBITDA[1,2]	**238**	122	**453**	342
Depreciation and amortization	**(36)**	(36)	**(73)**	(83)
Canadian Power - comparable EBIT[1,2]	**202**	86	**380**	259
U.S. Power (US$)				
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.

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	**three months ended June 30**		**six months ended June 30**	
(unaudited - millions of $, pre-tax)	**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.

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**
Revenues[1]				
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 EBITDA[3]	**106**	102	**230**	208
Depreciation and amortization	**(36)**	(36)	**(73)**	(83)
Comparable EBIT[3]	**70**	66	**157**	125
Breakdown of comparable EBITDA				
Western Power[3]	**23**	18	**53**	22
Eastern Power	**83**	84	**177**	186
Comparable EBITDA[3]	**106**	102	**230**	208
Plant availability[4]				
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.

Bruce Power

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $, unless noted otherwise)	**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 EBIT[1]	**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.

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.

	three months ended June 30		six months ended June 30	
(unaudited - millions of US$)	**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 EBITDA[3]	**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.

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.

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**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)

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**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.

Income tax expense

(unaudited - millions of $)	three months ended June 30 2017	2016	six months ended June 30 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 2017	2016	six months ended June 30 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 2017	2016	six months ended June 30 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.

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.

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.

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $, except per share amounts)	**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 operations[1]	**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 flow[1]	**936**	702	**2,158**	1,676
Comparable distributable cash flow per common share[1]	**$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.

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:

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**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.

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**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/subscription 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.

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	

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.

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of US$)	**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

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:

	June 30, 2017		December 31, 2016	
(unaudited - millions of Canadian $, unless noted otherwise)	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)

Unrealized and realized (losses)/gains of derivative instruments

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $, pre-tax)	**2017**	**2016**	**2017**	**2016**
Derivative instruments held for trading[1]				
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:

	three months ended June 30		six months ended June 30	
(unaudited - millions of $, pre-tax)	**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 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.

Reconciliation of non-GAAP measures

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**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	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**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

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

	2017		2016				2015	
(unaudited - millions of $, except per share amounts)	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.

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

- $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.

Condensed consolidated statement of income

(unaudited - millions of Canadian $, except per share amounts)	three months ended June 30		six months ended June 30	
	2017	**2016**	**2017**	**2016**
Revenues				
Canadian Natural Gas Pipelines	**922**	908	**1,804**	1,726
U.S. Natural Gas Pipelines	**879**	344	**1,873**	773
Mexico Natural Gas Pipelines	**150**	62	**293**	128
Liquids Pipelines	**501**	416	**973**	852
Energy	**765**	1,021	**1,665**	1,775
	3,217	2,751	**6,608**	5,254
Income from Equity Investments	**197**	66	**371**	201
Operating and Other Expenses				
Plant operating costs and other	**1,014**	754	**2,004**	1,469
Commodity purchases resold	**547**	375	**1,090**	845
Property taxes	**153**	128	**315**	269
Depreciation and amortization	**516**	444	**1,033**	898
Asset impairment charges	**—**	—	**—**	211
	2,230	1,701	**4,442**	3,692
Gain/(Loss) on Sale of Assets	**498**	—	**498**	(4)
Financial Charges				
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)
	314	397	**693**	616
Income before Income Taxes	**1,368**	719	**2,342**	1,143
Income Tax Expense				
Current	**55**	55	**122**	89
Deferred	**338**	219	**471**	255
	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
Dividends Declared per Common Share	**$0.625**	$0.565	**$1.25**	$1.13
Weighted Average Number of Common Shares (millions)				
Basic	**870**	703	**868**	703
Diluted	**872**	703	**870**	703

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

(unaudited - millions of Canadian $)	three months ended June 30		six months ended June 30	
	2017	**2016**	**2017**	**2016**
Net Income	**975**	445	**1,749**	799
Other Comprehensive (Loss)/Income, Net of Income Taxes				
Foreign currency translation (losses)/gains on net investment in foreign operations	**(269)**	5	**(351)**	(207)
Reclassification of foreign currency translation gains on net investment in foreign operations	**(77)**	—	**(77)**	—
Change in fair value of net investment hedges	**(1)**	(6)	**(2)**	(8)
Change in fair value of cash flow hedges	**(2)**	55	**3**	16
Reclassification to net income of gains and losses on cash flow hedges	**(1)**	(40)	**(1)**	40
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**4**	4	**7**	8
Other comprehensive income on equity investments	**—**	4	**3**	7
Other comprehensive (loss)/income (Note 8)	**(346)**	22	**(418)**	(144)
Comprehensive Income	**629**	467	**1,331**	655
Comprehensive income attributable to non-controlling interests	**6**	54	**56**	28
Comprehensive Income Attributable to Controlling Interests	**623**	413	**1,275**	627
Preferred share dividends	**39**	28	**80**	50
Comprehensive Income Attributable to Common Shares	**584**	385	**1,195**	577

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of cash flows

(unaudited - millions of Canadian $)	three months ended June 30 2017	three months ended June 30 2016	six months ended June 30 2017	six months ended June 30 2016
Cash Generated from Operations				
Net income	**975**	445	**1,749**	799
Depreciation and amortization	**516**	444	**1,033**	898
Asset impairment charges	**—**	—	**—**	211
Deferred income taxes	**338**	219	**471**	255
Income from equity investments	**(197)**	(66)	**(371)**	(201)
Distributions received from operating activities of equity investments	**228**	181	**447**	440
Employee post-retirement benefits expense, net of funding	**6**	(20)	**9**	(9)
(Gain)/loss on sale of assets	**(498)**	—	**(498)**	4
Equity allowance for funds used during construction	**(78)**	(67)	**(142)**	(124)
Unrealized losses/(gains) on financial instruments	**50**	(224)	**91**	(153)
Other	**(4)**	18	**4**	23
Decrease/(increase) in operating working capital	**17**	218	**(138)**	86
Net cash provided by operations	**1,353**	1,148	**2,655**	2,229
Investing Activities				
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)
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)
Financing Activities				
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 on common shares	**(328)**	(397)	**(628)**	(762)
Dividends on preferred shares	**(38)**	(23)	**(77)**	(46)
Distributions paid to non-controlling interests	**(69)**	(62)	**(149)**	(124)
Common shares/subscription receipts issued, net of issue costs	**18**	4,371	**36**	4,374
Common shares repurchased	**—**	—	**—**	(14)
Preferred shares issued, net of issue costs	**—**	492	**—**	492
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)**	—
Net cash (used in)/provided by financing activities	**(2,391)**	13,012	**(2,304)**	14,386
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(24)**	(73)	**(19)**	(130)
Increase in Cash and Cash Equivalents	**596**	489	**474**	877
Cash and Cash Equivalents				
Beginning of period	**894**	1,238	**1,016**	850
Cash and Cash Equivalents				
End of period	**1,490**	1,727	**1,490**	1,727

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		June 30, 2017	December 31, 2016
ASSETS			
Current Assets			
Cash and cash equivalents		**1,490**	1,016
Accounts receivable		**2,117**	2,075
Inventories		**393**	368
Assets held for sale		**—**	3,717
Other		**899**	908
		4,899	8,084
Plant, Property and Equipment	net of accumulated depreciation of $23,054 and $22,263, respectively	**55,951**	54,475
Equity Investments		**6,315**	6,544
Regulatory Assets		**1,306**	1,322
Goodwill		**13,569**	13,958
Intangible and Other Assets		**3,490**	3,026
Restricted Investments		**784**	642
		86,314	88,051
LIABILITIES			
Current Liabilities			
Notes payable		**1,559**	774
Accounts payable and other		**4,057**	3,861
Dividends payable		**557**	526
Accrued interest		**609**	595
Liabilities related to assets held for sale		**—**	86
Current portion of long-term debt		**3,270**	1,838
		10,052	7,680
Regulatory Liabilities		**2,376**	2,121
Other Long-Term Liabilities		**980**	1,183
Deferred Income Tax Liabilities		**8,054**	7,662
Long-Term Debt		**31,276**	38,312
Junior Subordinated Notes		**7,218**	3,931
		59,956	60,889
Common Units Subject to Rescission or Redemption		**—**	1,179
EQUITY			
Common shares, no par value		**20,544**	20,099
Issued and outstanding:	June 30, 2017 - 871 million shares		
	December 31, 2016 - 864 million shares		
Preferred shares		**3,980**	3,980
Additional paid-in capital		**—**	—
Retained earnings		**1,251**	1,138
Accumulated other comprehensive loss		**(1,289)**	(960)
Controlling Interests		**24,486**	24,257
Non-controlling interests		**1,872**	1,726
		26,358	25,983
		86,314	88,051

Commitments, Contingencies and Guarantees (Note 12)
Variable Interest Entities (Note 13)
Subsequent Event (Note 14)

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of equity

	six months ended June 30	
(unaudited - millions of Canadian $)	**2017**	**2016**
Common Shares		
Balance at beginning of period	**20,099**	12,102
Shares issued on exercise of stock options	**39**	29
Shares repurchased	**—**	(6)
Shares issued under dividend reinvestment and share purchase plan	**406**	—
Balance at end of period	**20,544**	12,125
Preferred Shares		
Balance at beginning and end of period	**3,980**	2,992
Additional Paid-In Capital		
Balance at beginning of period	**—**	7
Issuance of stock options, net of exercises	**2**	5
Dilution impact from TC PipeLines, LP units issued	**13**	12
Impact of common shares repurchased	**—**	(8)
Impact of asset drop downs to TC PipeLines, LP	**(202)**	(38)
Impact of Columbia Pipeline Partners LP acquisition	**(171)**	—
Reclassification of Additional Paid-In Capital deficit to Retained Earnings	**358**	22
Balance at end of period	**—**	—
Retained Earnings		
Balance at beginning of period	**1,138**	2,769
Net income attributable to controlling interests	**1,604**	667
Common share dividends	**(1,087)**	(794)
Preferred share dividends	**(58)**	(44)
Adjustment related to employee share-based payments (Note 2)	**12**	—
Reclassification of Additional Paid-In Capital deficit to Retained Earnings	**(358)**	(22)
Balance at end of period	**1,251**	2,576
Accumulated Other Comprehensive Loss		
Balance at beginning of period	**(960)**	(939)
Other comprehensive loss	**(329)**	(40)
Balance at end of period	**(1,289)**	(979)
Equity Attributable to Controlling Interests	**24,486**	16,714
Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	**1,726**	1,717
Net income attributable to non-controlling interests		
TC PipeLines, LP	**127**	110
Portland Natural Gas Transmission System	**9**	22
Columbia Pipeline Partners LP	**9**	—
Other comprehensive loss attributable to non-controlling interests	**(89)**	(104)
Issuance of TC PipeLines, LP units		
Proceeds, net of issue costs	**119**	106
Decrease in TransCanada's ownership of TC PipeLines, LP	**(21)**	(19)
Reclassification from/(to) common units of TC PipeLines, LP subject to rescission	**106**	(106)
Distributions declared to non-controlling interests	**(147)**	(125)
Impact of Columbia Pipeline Partners LP acquisition	**33**	—
Balance at end of period	**1,872**	1,601
Total Equity	**26,358**	18,315

See accompanying notes to the condensed consolidated financial statements.

Notes to condensed consolidated financial statements (unaudited)

1. Basis of presentation

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

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

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

USE OF ESTIMATES AND JUDGEMENTS

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

2. Accounting changes

CHANGES IN ACCOUNTING POLICIES FOR 2017

Inventory

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

Derivatives and hedging

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

Equity method investments

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

Employee share-based payments

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

Consolidation

In October 2016, the FASB issued new guidance on consolidation relating to interests held through related parties that are under common control. The new guidance amends the consolidation requirements such that if a decision maker is required to evaluate whether it is the primary beneficiary of a VIE, it will need to consider only its proportionate indirect interest in the VIE held through a common control party. The new guidance was effective January 1, 2017, was applied retrospectively and did not result in any change to the Company's consolidated 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. The Company will adopt the new standard on the effective date of January 1, 2018. There are two methods in which the new standard can be adopted: (1) a full retrospective approach with restatement of all prior periods presented, or (2) a modified retrospective approach with a cumulative-effect adjustment as of the date of adoption. The Company currently anticipates 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.

The Company has identified all existing customer contracts that are within the scope of the new guidance and is on schedule in the process of analyzing individual contracts or groups of contracts by operating segment to identify any significant changes in how revenues are recognized as a result of implementing the new guidance. While the Company has 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 the Company has not concluded on the overall impact of adopting the new guidance. The Company continues its contract analysis to obtain the information necessary to quantify the cumulative-effect adjustment, if any, on prior period revenues and revenue recognized going forward. The Company also continues to address any system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance.

Financial instruments

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

Leases

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

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

Measurement of credit losses on financial instruments

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

Income taxes

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

Restricted cash

In November 2016, the FASB issued new guidance on restricted cash and cash equivalents on the statement of cash flows. The new guidance requires that the statement of cash flows explain the change during the period in the total cash and cash equivalents balance, and amounts generally described as restricted cash or restricted cash equivalents. Restricted cash and cash equivalents will be included with Cash and cash equivalents when reconciling the beginning of year and end of year total amounts on the statement of cash flows. This new guidance is effective January 1, 2018 and will be applied retrospectively, 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. The Company is currently evaluating the impact of the adoption of this guidance, however, does not expect a material impact on its consolidated financial statements.

Amortization on purchased callable debt securities

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

3. Segmented information

three months ended June 30, 2017 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**922**	**879**	**150**	**501**	**765**	**—**	**3,217**
Income from equity investments	**2**	**57**	**5**	**(1)**	**142**	**(8)**	**197**
Plant operating costs and other	**(328)**	**(337)**	**(10)**	**(147)**	**(160)**	**(32)**	**(1,014)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(547)**	**—**	**(547)**
Property taxes	**(69)**	**(48)**	**—**	**(22)**	**(14)**	**—**	**(153)**
Depreciation and amortization	**(222)**	**(150)**	**(25)**	**(80)**	**(39)**	**—**	**(516)**
Gain on sale of assets	**—**	**—**	**—**	**—**	**498**	**—**	**498**
Segmented earnings/(loss)	**305**	**401**	**120**	**251**	**645**	**(40)**	**1,682**
Interest expense							**(524)**
Allowance for funds used during construction							**121**
Interest income and other							**89**
Income before income taxes							**1,368**
Income tax expense							**(393)**
Net income							**975**
Net income attributable to non-controlling interests							**(55)**
Net income attributable to controlling interests							**920**
Preferred share dividends							**(39)**
Net income attributable to common shares							**881**

three months ended June 30, 2016 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	908	344	62	416	1,021	—	2,751
Income from equity investments	3	37	—	(1)	27	—	66
Plant operating costs and other	(286)	(110)	(13)	(125)	(196)	(24)	(754)
Commodity purchases resold	—	—	—	—	(375)	—	(375)
Property taxes	(64)	(19)	—	(23)	(22)	—	(128)
Depreciation and amortization	(219)	(64)	(8)	(69)	(84)	—	(444)
Segmented earnings/(loss)	342	188	41	198	371	(24)	1,116
Interest expense							(514)
Allowance for funds used during construction							111
Interest income and other							6
Income before income taxes							719
Income tax expense							(274)
Net income							445
Net income attributable to non-controlling interests							(52)
Net income attributable to controlling interests							393
Preferred share dividends							(28)
Net income attributable to common shares							365

six months ended June 30, 2017 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**1,804**	**1,873**	**293**	**973**	**1,665**	**—**	**6,608**
Income from equity investments	**5**	**122**	**11**	**(1)**	**242**	**(8)**	**371**
Plant operating costs and other	**(640)**	**(632)**	**(19)**	**(292)**	**(356)**	**(65)**	**(2,004)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(1,090)**	**—**	**(1,090)**
Property taxes	**(138)**	**(95)**	**—**	**(45)**	**(37)**	**—**	**(315)**
Depreciation and amortization	**(444)**	**(306)**	**(47)**	**(157)**	**(79)**	**—**	**(1,033)**
Gain on sale of assets	**—**	**—**	**—**	**—**	**498**	**—**	**498**
Segmented earnings/(loss)	**587**	**962**	**238**	**478**	**843**	**(73)**	**3,035**
Interest expense							**(1,024)**
Allowance for funds used during construction							**222**
Interest income and other							**109**
Income before income taxes							**2,342**
Income tax expense							**(593)**
Net income							**1,749**
Net income attributable to non-controlling interests							**(145)**
Net income attributable to controlling interests							**1,604**
Preferred share dividends							**(80)**
Net income attributable to common shares							**1,524**

six months ended June 30, 2016 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	1,726	773	128	852	1,775	—	5,254
Income from equity investments	6	85	—	(1)	111	—	201
Plant operating costs and other	(546)	(228)	(26)	(254)	(364)	(51)	(1,469)
Commodity purchases resold	—	—	—	—	(845)	—	(845)
Property taxes	(137)	(40)	—	(46)	(46)	—	(269)
Depreciation and amortization	(435)	(131)	(16)	(141)	(175)	—	(898)
Asset impairment charges	—	—	—	—	(211)	—	(211)
Loss on sale of assets	—	(4)	—	—	—	—	(4)
Segmented earnings/(loss)	614	455	86	410	245	(51)	1,759
Interest expense							(934)
Allowance for funds used during construction							212
Interest income and other							106
Income before income taxes							1,143
Income tax expense							(344)
Net Income							799
Net income attributable to non-controlling interests							(132)
Net Income attributable to controlling interests							667
Preferred share dividends							(50)
Net Income attributable to common shares							617

TOTAL ASSETS

(unaudited - millions of Canadian $)	June 30, 2017	December 31, 2016
Canadian Natural Gas Pipelines	**16,564**	15,816
U.S. Natural Gas Pipelines	**34,926**	34,422
Mexico Natural Gas Pipelines	**5,386**	5,013
Liquids Pipelines	**16,789**	16,896
Energy	**9,181**	13,169
Corporate	**3,468**	2,735
	86,314	88,051

4. Income taxes

The effective tax rates for the six-month periods ended June 30, 2017 and 2016 were 25 per cent and 30 per cent, respectively. The lower effective tax rate in 2017 was primarily the result of lower flow-through taxes in 2017 on Canadian regulated pipelines and changes in the proportion of income earned between Canadian and foreign jurisdictions.

5. Long-term debt

LONG-TERM DEBT ISSUED

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

(unaudited - millions of Canadian $, unless noted otherwise) 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

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

(unaudited - millions of Canadian $, unless noted otherwise) 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 sale of the U.S. Northeast power assets were used to fully retire the remaining acquisition bridge facilities in second quarter 2017.

In the three and six months ended June 30, 2017, TransCanada capitalized interest related to capital projects of $56 million and $101 million (2016 - $46 million and $87 million).

6. Junior subordinated notes issued

(unaudited - millions of Canadian $, unless noted otherwise) **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%
TRANSCANADA PIPELINES LIMITED	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.

7. Common units subject to rescission or redemption

Columbia Pipeline Partners LP acquisition

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

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

Common units of TC PipeLines, LP subject to rescission

In March 2017, rescission rights on 0.4 million TC PipeLines, LP common units expired and $24 million was reclassified to equity.

During second quarter 2017, rescission rights on the remaining 1.2 million TC PipeLines, LP common units expired and $82 million (US$63 million) was reclassified to equity. At June 30, 2017, there were no outstanding Common units subject to rescission or redemption on the condensed consolidated balance sheet (December 31, 2016 - $106 million (US$82 million)).

8. Other comprehensive loss and accumulated other comprehensive loss

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

three months ended June 30, 2017 (unaudited - millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ Expense**	**Net of Tax Amount**
Foreign currency translation losses on net investment in foreign operations	**(265)**	**(4)**	**(269)**
Reclassification of foreign currency translation gains on net investment on disposal of foreign operations	**(77)**	**—**	**(77)**
Change in fair value of net investment hedges	**(1)**	**—**	**(1)**
Change in fair value of cash flow hedges	**(2)**	**—**	**(2)**
Reclassification to net income of gains and losses on cash flow hedges	**(2)**	**1**	**(1)**
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**5**	**(1)**	**4**
Other comprehensive loss	**(342)**	**(4)**	**(346)**

three months ended June 30, 2016 (unaudited - millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ Expense**	**Net of Tax Amount**
Foreign currency translation gains on net investment in foreign operations	5	—	5
Change in fair value of net investment hedges	(7)	1	(6)
Change in fair value of cash flow hedges	81	(26)	55
Reclassification to net income of gains and losses on cash flow hedges	(56)	16	(40)
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	6	(2)	4
Other comprehensive income on equity investments	5	(1)	4
Other comprehensive income	34	(12)	22

six months ended June 30, 2017 (unaudited - millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ Expense**	**Net of Tax Amount**
Foreign currency translation losses on net investment in foreign operations	**(353)**	**2**	**(351)**
Reclassification of foreign currency translation gains on net investment on disposal of foreign operations	**(77)**	**—**	**(77)**
Change in fair value of net investment hedges	**(3)**	**1**	**(2)**
Change in fair value of cash flow hedges	**4**	**(1)**	**3**
Reclassification to net income of gains and losses on cash flow hedges	**(2)**	**1**	**(1)**
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**10**	**(3)**	**7**
Other comprehensive income on equity investments	**4**	**(1)**	**3**
Other comprehensive loss	**(417)**	**(1)**	**(418)**

six months ended June 30, 2016 (unaudited - millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ Expense**	**Net of Tax Amount**
Foreign currency translation losses on net investment in foreign operations	(205)	(2)	(207)
Change in fair value of net investment hedges	(10)	2	(8)
Change in fair value of cash flow hedges	27	(11)	16
Reclassification to net income of gains and losses on cash flow hedges	64	(24)	40
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	11	(3)	8
Other comprehensive income on equity investments	9	(2)	7
Other comprehensive loss	(104)	(40)	(144)

The changes in AOCI by component are as follows:

three months ended June 30, 2017 (unaudited - millions of Canadian $)	**Currency Translation Adjustments**	**Cash Flow Hedges**	**Pension and OPEB Plan Adjustments**	**Equity Investments**	**Total**[1]
AOCI balance at April 1, 2017	**(418)**	**(24)**	**(205)**	**(345)**	**(992)**
Other comprehensive loss before reclassifications[2]	**(221)**	**(2)**	**—**	**—**	**(223)**
Amounts reclassified from accumulated other comprehensive loss	**(77)**	**(1)**	**4**	**—**	**(74)**
Net current period other comprehensive (loss)/ income	**(298)**	**(3)**	**4**	**—**	**(297)**
AOCI balance at June 30, 2017	**(716)**	**(27)**	**(201)**	**(345)**	**(1,289)**

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

2 Other comprehensive loss before reclassifications on currency translation adjustments is net of non-controlling interest losses of $49 million.

six months ended June 30, 2017 (unaudited - millions of Canadian $)	**Currency Translation Adjustments**	**Cash Flow Hedges**	**Pension and OPEB Plan Adjustments**	**Equity Investments**	**Total**[1]
AOCI balance at January 1, 2017	**(376)**	**(28)**	**(208)**	**(348)**	**(960)**
Other comprehensive (loss)/income before reclassifications[2]	**(263)**	**2**	**—**	**—**	**(261)**
Amounts reclassified from accumulated other comprehensive loss	**(77)**	**(1)**	**7**	**3**	**(68)**
Net current period other comprehensive (loss)/ income[3]	**(340)**	**1**	**7**	**3**	**(329)**
AOCI balance at June 30, 2017	**(716)**	**(27)**	**(201)**	**(345)**	**(1,289)**

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

2 Other comprehensive (loss)/income before reclassifications on currency translation adjustments and cash flow hedges is net of non-controlling interest losses of $90 million and gains of $1 million, respectively.

3 Losses related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be $9 million ($6 million, net of tax) at June 30, 2017. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

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

	Amounts reclassified from accumulated other comprehensive loss[1]				Affected line item in the condensed consolidated statement of income
	three months ended June 30		six months ended June 30		
(unaudited - millions of Canadian $)	**2017**	**2016**	**2017**	**2016**	
Cash flow hedges					
Commodities	**7**	21	**11**	(61)	Revenue (Energy)
Foreign exchange	**—**	39	**—**	5	Interest income and other
Interest rate	**(5)**	(4)	**(9)**	(8)	Interest expense
	2	56	**2**	(64)	Total before tax
	(1)	(16)	**(1)**	24	Income tax expense
	1	40	**1**	(40)	Net of tax
Pension and other post-retirement benefit plan adjustments					
Amortization of actuarial loss	**(4)**	(6)	**(8)**	(11)	Plant operating costs [2]
	1	2	**3**	3	Income tax expense
	(3)	(4)	**(5)**	(8)	Net of tax
Equity investments					
Equity income	**—**	(5)	**(4)**	(9)	Income from equity investments
	—	1	**1**	2	Income tax expense
	—	(4)	**(3)**	(7)	Net of tax
Currency translation adjustments					
Realization of foreign currency translation gain on disposal of foreign operations	**77**	—	**77**	—	Gain/(loss) on sale of assets
	—	—	**—**	—	Income tax expense
	77	—	**77**	—	Net of tax

1 All amounts in parentheses indicate expenses to the condensed consolidated statement of income.

2 These accumulated other comprehensive loss components are included in the computation of net benefit cost. Refer to Note 9 for additional detail.

9. Employee post-retirement benefits

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

	three months ended June 30				six months ended June 30			
	Pension benefit plans		Other post-retirement benefit plans		Pension benefit plans		Other post-retirement benefit plans	
(unaudited - millions of Canadian $)	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Service cost	**27**	25	**1**	—	**56**	51	**2**	1
Interest cost	**28**	29	**3**	3	**62**	59	**7**	5
Expected return on plan assets	**(39)**	(39)	**(6)**	(1)	**(89)**	(79)	**(11)**	(1)
Amortization of actuarial loss	**4**	6	**—**	—	**8**	10	**—**	1
Amortization of regulatory asset	**1**	5	**1**	—	**7**	9	**1**	—
Amortization of transitional obligation related to regulated business	**—**	—	**—**	1	**—**	—	**—**	1
Net benefit cost recognized	**21**	26	**(1)**	3	**44**	50	**(1)**	7

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

10. Risk management and financial instruments

RISK MANAGEMENT OVERVIEW

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

COUNTERPARTY CREDIT RISK

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

LOAN RECEIVABLE FROM AFFILIATE

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

TransCanada holds a 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline for which it accounts as an equity investment. On April 21, 2017, TransCanada 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 the Company's 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 TransCanada's proportionate share of its affiliate's debt financing requirements and is included in Contributions to equity investments on the Company's condensed consolidated statement of cash flows.

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).

NET INVESTMENT IN FOREIGN OPERATIONS

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

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

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

(unaudited - millions of Canadian $, unless noted otherwise)	**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)

Derivatives designated as a net investment hedge

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

	June 30, 2017		**December 31, 2016**	
(unaudited - millions of Canadian $, unless noted otherwise)	**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 swap settlements are included in interest expense.

FINANCIAL INSTRUMENTS

Non-derivative financial instruments

Fair value of non-derivative financial instruments

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

Available for sale assets are recorded at fair value which is calculated using quoted market prices where available. Certain non-derivative financial instruments included in cash and cash equivalents, accounts receivable, intangible and other assets, notes payable, accounts payable and other, accrued interest and other long-term liabilities have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity and would also be classified in Level II of the fair value hierarchy.

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

Balance sheet presentation of non-derivative financial instruments

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

(unaudited - millions of Canadian $)	June 30, 2017		December 31, 2016	
	Carrying amount	Fair value	Carrying amount	Fair value
Notes receivable[1]	**—**	**—**	165	211
Long-term debt including current portion[2,3]	**(34,546)**	**(39,892)**	(40,150)	(45,047)
Junior subordinated notes	**(7,218)**	**(7,505)**	(3,931)	(3,825)
	(41,764)	**(47,397)**	(43,916)	(48,661)

1 Notes receivable was included in Assets held for sale at December 31, 2016 on the condensed consolidated balance sheet. The fair value was calculated based on the original contract terms.
2 Long-term debt is recorded at amortized cost except for US$850 million (December 31, 2016 - US$850 million) that is attributed to hedged risk and recorded at fair value.
3 Consolidated net income for the three and six months ended June 30, 2017 included unrealized losses of $1 million and unrealized gains of $1 million, respectively, (2016 - unrealized losses of $1 million and $13 million, respectively) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$850 million of long-term debt at June 30, 2017 (December 31, 2016 - US$850 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Available for sale assets summary

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

(unaudited - millions of Canadian $)	June 30, 2017		December 31, 2016	
	LMCI restricted investments	Other restricted investments[2]	LMCI restricted investments	Other restricted investments[2]
Fair Values[1]				
Fixed income securities (maturing within 1 year)	**—**	**30**	—	19
Fixed income securities (maturing within 1-5 years)	**—**	**107**	—	117
Fixed income securities (maturing within 5-10 years)	**15**	**—**	9	—
Fixed income securities (maturing after 10 years)	**659**	**—**	513	—
	674	**137**	522	136

1 Available for sale assets are recorded at fair value and included in other current assets and restricted investments on the condensed consolidated balance sheet.
2 Other restricted investments have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

(unaudited - millions of Canadian $)	June 30, 2017		June 30, 2016	
	LMCI restricted investments[1]	Other restricted investments[2]	LMCI restricted investments[1]	Other restricted investments[2]
Net unrealized gains in the period				
three months ended	**13**	**—**	17	—
six months ended	**15**	**—**	22	1
Net realized losses in the period				
three months ended	**(1)**	**—**	—	—
six months ended	**(1)**	**—**	—	—

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

Derivative instruments

Fair value of derivative instruments

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

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

Balance sheet presentation of derivative instruments

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

at June 30, 2017 (unaudited - millions of Canadian $)	**Cash Flow Hedges**	**Fair Value Hedges**	**Net Investment Hedges**	**Held for Trading**	**Total Fair Value of Derivative Instruments**[1]
Other current assets					
Commodities[2]	**4**	**—**	**—**	**268**	**272**
Foreign exchange	**—**	**—**	**3**	**42**	**45**
Interest rate	**2**	**—**	**—**	**1**	**3**
	6	**—**	**3**	**311**	**320**
Intangible and other assets					
Commodities[2]	**1**	**—**	**—**	**121**	**122**
Foreign exchange	**—**	**—**	**4**	**—**	**4**
	1	**—**	**4**	**121**	**126**
Total Derivative Assets	**7**	**—**	**7**	**432**	**446**
Accounts payable and other					
Commodities[2]	**(1)**	**—**	**—**	**(354)**	**(355)**
Foreign exchange	**—**	**—**	**(162)**	**(13)**	**(175)**
Interest rate	**—**	**(2)**	**—**	**—**	**(2)**
	(1)	**(2)**	**(162)**	**(367)**	**(532)**
Other long-term liabilities					
Commodities[2]	**—**	**—**	**—**	**(162)**	**(162)**
Foreign exchange	**—**	**—**	**(85)**	**—**	**(85)**
Interest rate	**—**	**(1)**	**—**	**—**	**(1)**
	—	**(1)**	**(85)**	**(162)**	**(248)**
Total Derivative Liabilities	**(1)**	**(3)**	**(247)**	**(529)**	**(780)**
Total Derivatives	**6**	**(3)**	**(240)**	**(97)**	**(334)**

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

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

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

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

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

Notional and Maturity Summary

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

at June 30, 2017 (unaudited)	Power	Natural Gas	Liquids	Foreign Exchange	Interest
Purchases[1]	**103,510**	**186**	**12**	**—**	**—**
Sales[1]	**65,642**	**167**	**13**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**US 2,722**	**US 1,550**
Millions of Mexican pesos	**—**	**—**	**—**	**MXN 300**	**—**
Maturity dates	**2017-2021**	**2017-2020**	**2017**	**2017-2018**	**2017-2019**

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

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

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

Unrealized and Realized (Losses)/Gains of Derivative Instruments

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $)	2017	2016	2017	2016
Derivative instruments held for trading[1]				
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 derivative instruments held for trading are included net in Interest expense and Interest income and other, respectively.

2 Following the March 17, 2016 announcement of the Company's intention to sell the U.S. Northeast power assets, 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 OCI (Note 8) related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests are as follows:

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $, pre-tax)	**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.

Offsetting of derivative instruments

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

at June 30, 2017 (unaudited - millions of Canadian $)	**Gross derivative instruments presented on the balance sheet**	**Amounts available for offset**[1]	**Net amounts**
Derivative - Asset			
Commodities	**394**	**(313)**	**81**
Foreign exchange	**49**	**(43)**	**6**
Interest rate	**3**	**(1)**	**2**
Total	**446**	**(357)**	**89**
Derivative - Liability			
Commodities	**(517)**	**313**	**(204)**
Foreign exchange	**(260)**	**43**	**(217)**
Interest rate	**(3)**	**1**	**(2)**
Total	**(780)**	**357**	**(423)**

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

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

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

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

With respect to the derivative instruments presented above as at June 30, 2017, the Company provided cash collateral of $381 million (December 31, 2016 - $305 million) and letters of credit of $7 million (December 31, 2016 - $27 million) to its counterparties. The Company held nil (December 31, 2016 - nil) in cash collateral and $3 million (December 31, 2016 - $3 million) in letters of credit from counterparties on asset exposures at June 30, 2017.

Credit risk related contingent features of derivative instruments

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

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

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

FAIR VALUE HIERARCHY

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

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

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

at June 30, 2017 (unaudited - millions of Canadian $)	**Quoted prices in active markets (Level I)**[1]	**Significant other observable inputs (Level II)**[1]	**Significant unobservable inputs (Level III)**[1]	**Total**
Derivative instrument assets:				
Commodities	**42**	**325**	**27**	**394**
Foreign exchange	**—**	**49**	**—**	**49**
Interest rate	**—**	**3**	**—**	**3**
Derivative instrument liabilities:				
Commodities	**(42)**	**(457)**	**(18)**	**(517)**
Foreign exchange	**—**	**(260)**	**—**	**(260)**
Interest rate	**—**	**(3)**	**—**	**(3)**
	—	**(343)**	**9**	**(334)**

1 There were no transfers from Level I to Level II or from Level II to Level III for the six months ended June 30, 2017.

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

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

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

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

	three months ended June 30		**six months ended June 30**	
(unaudited - millions of Canadian $)	**2017**	**2016**	**2017**	**2016**
Balance at beginning of period	**10**	9	**16**	9
Settlements	**5**	(4)	**5**	(3)
Sales	**(3)**	—	**(5)**	(1)
Total (losses)/gains included in net income	**(2)**	7	**(2)**	10
Transfers out of Level III	**(1)**	—	**(5)**	(3)
Balance at end of period[1]	**9**	12	**9**	12

1 For the three and six months ended June 30, 2017, revenues include unrealized losses of $1 million and gains of $1 million, respectively, attributed to derivatives in the Level III category that were still held at June 30, 2017 (2016 - gains of $6 million and $8 million, respectively).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $1 million increase or $3 million decrease, respectively, in the fair value of outstanding derivative instruments included in Level III as at June 30, 2017.

11. Acquisitions & Dispositions

U.S. Natural Gas Pipelines

Iroquois Gas Transmission System and Gas Transmission Northwest LLC

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

Columbia Pipeline Group

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

Energy

U.S. Northeast Power Assets

On June 2, 2017, TransCanada completed the sale of Ravenswood, Ironwood, Kibby Wind and Ocean State Power for proceeds of approximately US$2.029 billion, subject to post-closing adjustments. The Company recorded an additional loss on sale of $219 million ($176 million after tax) which included $2 million in foreign currency translation gains. The additional loss was primarily related to an adjustment to the purchase price and repair costs for an unplanned outage at Ravenswood prior to close. In 2016, the Company recorded a loss of approximately $829 million ($863 million after tax) which included the impact of an estimated $70 million of foreign currency translation gains. The actual foreign currency translation gains of $72 million were reclassified from AOCI to Net income on closing of the transaction.

On April 19, 2017, the Company completed the sale of TC Hydro for gross proceeds of US$1.07 billion, subject to post-closing adjustments. As a result, the Company recorded a gain on sale of approximately $717 million ($441 million after tax) including the impact of an estimated $5 million of foreign currency translation gains which were reclassified from AOCI to net income.

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

12. Commitments, contingencies and guarantees

COMMITMENTS

TransCanada's operating lease commitments at December 31, 2016 included future payments related to our U.S. Northeast power assets. As a result of the completion of the thermal 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.

CONTINGENCIES

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

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

GUARANTEES

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

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

The Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities. Such agreements include guarantees and letters of credit which are primarily related to delivery of natural gas, construction services and the payment of liabilities. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

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

		at June 30, 2017		at December 31, 2016	
(unaudited - millions of Canadian $)	Term	Potential exposure[1]	Carrying value	Potential exposure[1]	Carrying value
Sur de Texas	ranging to 2020	**571**	**6**	805	53
Bruce Power	ranging to 2018	**88**	**1**	88	1
Other jointly owned entities	ranging to 2059	**107**	**14**	87	28
		766	**21**	980	82

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

13. Variable interest entities

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

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

Consolidated VIEs

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

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

(unaudited - millions of Canadian $)	June 30, 2017	December 31, 2016
ASSETS		
Current Assets		
Cash and cash equivalents	**66**	77
Accounts receivable	**59**	71
Inventories	**24**	25
Other	**8**	10
	157	183
Plant, Property and Equipment	**3,704**	3,685
Equity Investments	**861**	606
Goodwill	**508**	525
Intangible and Other Assets	**—**	1
	5,230	5,000
LIABILITIES		
Current Liabilities		
Accounts payable and other	**67**	80
Accrued interest	**23**	21
Current portion of long-term debt	**99**	76
	189	177
Regulatory Liabilities	**33**	34
Other Long-Term Liabilities	**3**	4
Deferred Income Tax Liabilities	**13**	7
Long-Term Debt	**3,353**	2,827
	3,591	3,049

Non-Consolidated VIEs

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

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

(unaudited - millions of Canadian $)	June 30, 2017	December 31, 2016
Balance sheet		
Equity investments	**4,393**	4,964
Off-balance sheet		
Potential exposure to guarantees	**173**	163
Maximum exposure to loss	**4,566**	5,127

14. Subsequent event

On July 25, 2017, the Company was notified that PNW LNG would not be proceeding with their proposed LNG project. As part of the PRGT agreement, following receipt of a termination notice, TransCanada would be reimbursed for the full costs and carrying charges incurred to advance the PRGT project. At June 30, 2017, approximately $0.5 billion was included in Intangible and other assets on the Company's condensed consolidated balance sheet.