QuarterlyReport to Shareholders

TransCanada
In business to deliver

TransCanada Reports First Quarter 2017 Financial Results
Strong Results Build Upon Transformational 2016

CALGARY, Alberta – **May 5, 2017** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada) today announced net income attributable to common shares for first quarter 2017 of $643 million or $0.74 per share compared to net income of $252 million or $0.36 per share for the same period in 2016. Comparable earnings for first quarter 2017 were $698 million or $0.81 per share compared to $494 million or $0.70 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 June 30, 2017, equivalent to $2.50 per common share on an annualized basis.

"We generated record first quarter financial results, excluding specific items," said Russ Girling, TransCanada's president and chief executive officer. "Comparable earnings per share increased 16 per cent compared to first quarter 2016 primarily due to strong performance across our Natural Gas Pipelines business, including Columbia which was acquired in mid-2016, while net cash provided by operations reached $1.3 billion."

"Today we are advancing a $23 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 $7.5 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 purchase of Columbia Pipeline Partners LP which results in 100 per cent ownership in the core Columbia assets and further simplifies our corporate structure."

"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. Those include Keystone XL and the Bruce Power life extension agreement. During the first quarter, we were very pleased to receive a U.S. Presidential Permit for Keystone XL and are now in the process of seeking regulatory approval in Nebraska while progressing commercial discussions with our customers. Success in advancing these or other growth initiatives could augment or extend the Company's dividend growth outlook through 2020 and beyond," concluded Girling.

Highlights

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

- First quarter 2017 financial results
  - Net income attributable to common shares of $643 million or $0.74 per share
  - Comparable earnings of $698 million or $0.81 per share
  - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $2.0 billion
  - Net cash provided by operations of $1.3 billion
  - Comparable funds generated from operations of $1.5 billion
  - Comparable distributable cash flow of $1.2 billion or $1.41 per common share
- Declared a quarterly dividend of $0.625 per common share for the quarter ending June 30, 2017
- Acquired all outstanding publicly held units of Columbia Pipeline Partners LP (CPPL) for a total of US$921 million
- Filed a variance application with the National Energy Board (NEB) for the $1.4 billion North Montney project to remove the condition requiring a positive Final Investment Decision (FID) for the Pacific Northwest LNG project. The amended project is supported by 20-year contracts with 11 shippers

- Successfully concluded an open season on the Canadian Mainline for 1.5 petajoules per day (PJ/d) of 10 year transportation service from Empress, Alberta to the Dawn hub in Southern Ontario
- Received Federal Energy Regulatory Commission (FERC) approvals and began construction on the Leach XPress and Rayne XPress projects. Also received an Environmental Assessment on WB XPress
- Received a U.S. Presidential Permit authorizing construction of the U.S./Canada border crossing facilities of the Keystone XL pipeline. We also filed an application with the Nebraska Public Service Commission seeking approval for the Keystone XL pipeline route through that state
- Raised US$1.5 billion in gross proceeds through an offering of Junior Subordinated Notes maturing in 2077
- In April, closed the sale of a portion of our U.S. Northeast power business for US$1.065 billion; the proceeds were used to repay a portion of the acquisition bridge facilities which partially financed the Columbia acquisition
- In May, announced agreements to sell a 49.3 per cent interest in Iroquois Gas Transmission System, LP (Iroquois), together with our remaining 11.8 per cent interest in Portland Natural Gas Transmission System (PNGTS), to our master limited partnership, TC PipeLines, LP for a total of US$765 million

Net income attributable to common shares increased by $391 million to $643 million or $0.74 per share for the three months ended March 31, 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. First quarter 2017 included a charge of $24 million after-tax for integration-related costs associated with the acquisition of Columbia, a $10 million after-tax charge for costs related to the monetization of our U.S. Northeast power business, a $7 million after-tax charge related to the maintenance of Keystone XL assets and a $7 million income tax recovery related to the realized loss on a third party sale of Keystone XL project assets. First quarter 2016 results included a $176 million after-tax impairment charge on the carrying value of our Alberta PPAs, a $26 million after-tax charge relating to costs associated with the acquisition of Columbia, a $6 million after-tax charge related to Keystone XL costs for the maintenance and liquidation of project assets and a $3 million after-tax loss on the sale of TC Offshore which closed in March 2016. All of these specific items plus risk management activities are excluded from comparable earnings.

Comparable earnings for first quarter 2017 were $698 million or $0.81 per share compared to $494 million or $0.70 per share for the same period in 2016, an increase of $204 million or $0.11 per share and includes the dilutive effect of issuing 161 million common shares in 2016. The 2017 increase in comparable earnings was primarily due to the net effect of higher contributions from U.S. Natural Gas Pipelines primarily due to incremental earnings from Columbia following the July 1, 2016 acquisition and higher ANR transportation revenues resulting from higher rates effective August 1, 2016, a higher contribution from Mexican Natural Gas Pipelines due to incremental earnings from the Mazatlán and Topolobampo pipelines, higher earnings primarily from U.S. Power due to depreciation no longer being recorded effective November 1, 2016 on these assets along with higher realized power prices and higher earnings from Western Power following the termination of the Alberta PPAs in 2016. These increases were partially offset by higher interest expense as a result of debt assumed in the Columbia acquisition and long-term debt issuances and lower earnings from Bruce Power mainly due to lower gains from contracting activities and higher interest expense partially offset by higher volumes resulting from fewer outage days.

Notable recent developments include:

Natural Gas Pipelines:

- *NGTL System*: NGTL currently has a $5.1 billion near-term capital program targeted for completion by 2020. This includes the recently filed application to amend approvals for the North Montney project with a revised $1.4 billion capital cost estimate and the recently approved Towerbirch Expansion project.
- *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 it can 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 a group of shippers and is not dependent on, but still accommodates, the LNG project proceeding. 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. 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 Empress, Alberta to the Dawn hub in Southern Ontario. The open season resulted in binding, long-term contracts to transport 1.5 PJ/d of natural gas at a toll of $0.77/GJ. The 10 year contracts have 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 and included the request to implement the service starting November 1, 2017.
- *Sale of Iroquois and PNGTS to TC PipeLines, LP:* On May 4, 2017, we announced agreements to sell a 49.3 per cent interest in Iroquois, together with our remaining 11.8 per cent interest in PNGTS, to our master limited partnership, TC PipeLines, LP for US$765 million. The transaction is expected to close mid-2017.
- *Columbia Projects:* Leach XPress and Rayne XPress both received FERC approvals and Notices to Proceed in the first quarter of 2017. Construction is now underway. The US$1.4 billion Leach XPress project and the US$0.4 billion Rayne XPress project are expected to be in-service in November 2017. WB XPress received an Environmental Assessment on March 24, 2017 and expects to receive its FERC order later this summer. The US$0.8 billion project remains on schedule with Phase I expected to be in-service in June 2018 and Phase II in November 2018.
- *Columbia Pipeline Partners LP:* On February 17, 2017, we acquired, for cash, all of the outstanding publicly held common units of CPPL for an aggregate transaction value of US$921 million.
- *Great Lakes Rate Filing:* Consistent with its 2013 settlement, 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 become effective on October 1, 2017, subject to refund, if alternate resolution to the proceeding is not reached prior to that date. We have initiated customer discussions and will seek to achieve a mutually beneficial settlement resolution.

Liquids Pipelines:

- *Keystone XL:* In March 2017, the U.S. Department of State issued a U.S. Presidential Permit authorizing construction of the U.S./Canada border crossing facilities of the Keystone XL pipeline. We have discontinued our claim under Chapter 11 of the North American Free Trade Agreement and have withdrawn the U.S. Constitutional challenge. In February 2017, we filed an application with the Nebraska Public Service Commission 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 is expected by the end of November 2017. 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 expect this transition to be complete within a few months and would anticipate commercial support for the project to be substantially similar to that which existed when we first applied for Keystone XL.

Energy:

- *Monetization of U.S. Northeast power business:* On April 19, 2017, we announced the closing of the previously announced sale of TC Hydro to Great River Hydro, LLC, an affiliate of ArcLight Capital Partners, LLC, for US$1.065 billion. In second quarter 2017 we expect to book an approximate $440 million after-tax gain on the sale of the hydro assets. The proceeds received were used to reduce the acquisition bridge facilities which partially financed the Columbia acquisition. The previously announced sale of Ravenswood, Ironwood, Ocean State Power and Kibby to Helix Generation, LLC is expected to close in second quarter 2017.

Corporate:

- *Common Share Dividend:* Our Board of Directors declared a quarterly dividend of $0.625 per share for the quarter ending June 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 March 2017, TransCanada Trust issued US$1.5 billion of 60-year Junior Subordinated 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. 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 TCPL in US$1.5 billion of subordinated notes at a rate of 5.55 per cent which includes a 0.25 per cent administration charge.
- *Dividend Reinvestment Plan:* Currently, approximately 40 per cent of the common and preferred share dividends declared are being reinvested in TransCanada common shares through our Dividend Reinvestment Plan (DRP).
- *Management Changes:* Alex Pourbaix, Chief Operating Officer announced his retirement from the company, effective May 31, 2017. There is no current intention to replace this role. Effective April 28, 2017, Stan Chapman, previously Senior Vice-President of U.S. Natural Gas Pipelines, was promoted to Executive Vice-President and President, U.S. Natural Gas Pipelines. On April 21, 2017, Bill Taylor, Executive Vice-President and President, Energy left the company to pursue other opportunities and Karl Johannson will take over the responsibility of the Energy business unit along with his revised role as President of Canada and Mexico Natural Gas Pipelines.

Teleconference and Webcast:

We will hold a teleconference and webcast on Friday, May 5, 2017 to discuss our first 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 12:30 p.m. (MT) / 2:30 p.m. (ET).

Members of the investment community and other interested parties are invited to participate by calling 800.408.3053 or 905.694.9451 (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 May 12, 2017. Please call 800.408.3053 or 905.694.9451 (Toronto area) and enter pass code 8663009.

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 over 10,100 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 May 4, 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 May 4, 2017.

- 30 -

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First quarter 2017 financial highlights

	three months ended March 31	
(unaudited - millions of $, except per share amounts)	**2017**	**2016**
Income		
Revenues	**3,391**	2,503
Net income attributable to common shares	**643**	252
per common share - basic and diluted	**$0.74**	$0.36
Comparable EBITDA[1]	**1,977**	1,502
Comparable earnings[1]	**698**	494
per common share[1]	**$0.81**	$0.70
Cash flows		
Net cash provided by operations	**1,302**	1,081
Comparable funds generated from operations[1]	**1,508**	1,249
Comparable distributable cash flow[1]	**1,222**	974
per common share[1]	**$1.41**	$1.39
Capital spending - capital expenditures	**1,560**	836
- projects in development	**42**	67
Contributions to equity investments	**192**	170
Acquisitions, net of cash acquired	**—**	995
Proceeds from sale of assets, net of transaction costs	**—**	6
Dividends declared		
Per common share	**$0.625**	$0.565
Basic common shares outstanding (millions)		
Average for the period	**866**	702
End of period	**867**	702

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

May 4, 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 months ended March 31, 2017, and should be read with the accompanying unaudited condensed consolidated financial statements for the three months ended March 31, 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 including the divestiture of certain assets
- our financial and operational performance, including the performance of our subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows and future financing options available to us
- expected dividend growth
- expected costs for planned projects, including projects under construction, permitting and in development
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes
- expected impact of regulatory outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- expected capital expenditures and contractual obligations
- expected operating and financial results
- expected impact of future accounting changes, commitments and contingent liabilities
- expected industry, market and economic conditions.

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

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

Assumptions

- planned monetization of our U.S. Northeast power business
- inflation rates, commodity prices and capacity prices
- nature and scope of hedging
- regulatory decisions and outcomes
- the Canadian dollar to U.S. dollar exchange rate remains at or near current levels
- 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
- timing and execution of our planned asset sales
- 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 or assets held for sale
- legal, contractual and bankruptcy settlements
- impact of regulatory or arbitration decisions relating to prior year earnings
- restructuring costs
- impairment of goodwill, investments and other assets 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

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

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 - first 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 March 31	
(unaudited - millions of $, except per share amounts)	**2017**	**2016**
Canadian Natural Gas Pipelines	**282**	272
U.S. Natural Gas Pipelines	**561**	267
Mexico Natural Gas Pipelines	**118**	45
Liquids Pipelines	**227**	212
Energy	**198**	(126)
Corporate	**(33)**	(27)
Total segmented earnings	**1,353**	643
Interest expense	**(500)**	(420)
Allowance for funds used during construction	**101**	101
Interest income and other	**20**	100
Income before income taxes	**974**	424
Income tax expense	**(200)**	(70)
Net income	**774**	354
Net income attributable to non-controlling interests	**(90)**	(80)
Net income attributable to controlling interests	**684**	274
Preferred share dividends	**(41)**	(22)
Net income attributable to common shares	**643**	252
Net income per common share - basic and diluted	**$0.74**	$0.36

Net income attributable to common shares increased by $391 million or $0.38 per share for the three months ended March 31, 2017 compared to the same period 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 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.

The 2016 results included:

- 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 after tax relating 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.

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 $204 million for the three months ended March 31, 2017 compared to the same period in 2016 as discussed below in the reconciliation of net income to comparable earnings.

RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS

	three months ended March 31	
(unaudited - millions of $, except per share amounts)	**2017**	**2016**
Net income attributable to common shares	**643**	252
Specific items (net of tax):		
Acquisition related costs - Columbia	**24**	26
U.S. Northeast power monetization	**10**	—
Keystone XL asset costs	**7**	6
Keystone XL income tax recoveries	**(7)**	—
Alberta PPA terminations	**—**	176
TC Offshore loss on sale	**—**	3
Risk management activities[1]	**21**	31
Comparable earnings	**698**	494
Net income per common share	**$0.74**	$0.36
Specific items (net of tax):		
Acquisition related costs - Columbia	**0.03**	0.04
U.S. Northeast power monetization	**0.01**	—
Keystone XL asset costs	**0.01**	0.01
Keystone XL income tax recoveries	**(0.01)**	—
Alberta PPA terminations	**—**	0.25
Risk management activities	**0.03**	0.04
Comparable earnings per share	**$0.81**	$0.70

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Risk management activities	three months ended March 31	
(unaudited - millions of $)	**2017**	**2016**
Canadian Power	**1**	(13)
U.S. Power	**(62)**	(115)
Liquids marketing	**—**	(2)
Natural Gas Storage	**5**	5
Foreign exchange	**15**	53
Income tax attributable to risk management activities	**20**	41
Total unrealized losses from risk management activities	**(21)**	(31)

Comparable earnings increased by $204 million or $0.11 per share for the three months ended March 31, 2017 compared to the same period in 2016. Comparable earnings per share in 2017 included the dilutive effect of issuing 161 million common shares in 2016.

The year-over-year increase in comparable earnings 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
- lower interest income and other due to 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
- lower earnings from Bruce Power mainly due to lower gains from contracting activities and higher interest expense, partially offset by higher volumes resulting from fewer outage days
- higher earnings from Western Power mainly due to termination of the Alberta PPAs in 2016
- higher earnings from Liquids Pipelines due to higher volumes
- higher earnings from Natural Gas Storage due to higher realized natural gas storage price spreads
- higher earnings from U.S. Power due to depreciation no longer being recorded effective November 1, 2016 on the assets classified as held for sale and higher realized power prices, partially offset by lower capacity revenues in New York and higher fuel costs and lower generation volumes at our New York and New England facilities.

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 $23 billion of near-term projects and approximately $48 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 March 31, 2017 (unaudited - billions of $)	**Segment**	**Expected in-service date**	**Estimated project cost**	**Carrying value**
Canadian Mainline	Canadian Natural Gas Pipelines	2017-2018	0.3	0.1
NGTL System – North Montney	Canadian Natural Gas Pipelines	2019-2020	1.4	0.3
– Saddle West	Canadian Natural Gas Pipelines	2019	0.6	—
– 2016/17 Facilities	Canadian Natural Gas Pipelines	2017-2020	2.2	0.9
– 2018 Facilities	Canadian Natural Gas Pipelines	2018-2020	0.6	—
– Other	Canadian Natural Gas Pipelines	2017-2020	0.3	—
Columbia Gas – Leach XPress	U.S. Natural Gas Pipelines	2017	US 1.4	US 0.5
– Modernization I	U.S. Natural Gas Pipelines	2017	US 0.2	US 0.1
– WB XPress	U.S. Natural Gas Pipelines	2018	US 0.8	US 0.3
– Mountaineer XPress	U.S. Natural Gas Pipelines	2018	US 2.0	US 0.2
– Modernization II	U.S. Natural Gas Pipelines	2018-2020	US 1.1	—
Columbia Gulf – Rayne XPress	U.S. Natural Gas Pipelines	2017	US 0.4	US 0.3
– Cameron Access	U.S. Natural Gas Pipelines	2018	US 0.3	US 0.2
– Gulf XPress	U.S. Natural Gas Pipelines	2018	US 0.6	US 0.1
Midstream – Gibraltar	U.S. Natural Gas Pipelines	2017	US 0.3	US 0.2
Tula	Mexico Natural Gas Pipelines	2018	US 0.6	US 0.4
Villa de Reyes	Mexico Natural Gas Pipelines	2018	US 0.6	US 0.3
Sur de Texas[1]	Mexico Natural Gas Pipelines	2018	US 1.3	US 0.2
Grand Rapids[1]	Liquids Pipelines	2017	0.9	0.8
Northern Courier	Liquids Pipelines	2017	1.0	0.9
White Spruce	Liquids Pipelines	2018	0.2	—
Napanee	Energy	2018	1.1	0.7
Bruce Power – life extension[2]	Energy	up to 2020+	1.1	0.1
			19.3	**6.6**
Foreign exchange impact on near-term projects[3]			**3.2**	**0.9**
Total near-term projects (billions of Cdn$)			**22.5**	**7.5**

1 Our proportionate share.

2 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.

3 Reflects U.S./Canada foreign exchange rate of $1.33 at March 31, 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 March 31, 2017 (unaudited - billions of $)	**Segment**	**Estimated project cost**	**Carrying value**
Heartland and TC Terminals	Liquids Pipelines	0.9	0.1
Upland	Liquids Pipelines	US 0.6	—
Grand Rapids Phase 2[1]	Liquids Pipelines	0.7	—
Bruce Power - life extension[1]	Energy	5.3	—
Keystone projects			
Keystone XL[2]	Liquids Pipelines	US 8.0	US 0.3
Keystone Hardisty Terminal[2]	Liquids Pipelines	0.3	0.1
Energy East projects			
Energy East[3]	Liquids Pipelines	15.7	0.8
Eastern Mainline	Canadian Natural Gas Pipelines	2.0	0.1
BC west coast LNG-related projects			
Coastal GasLink	Canadian Natural Gas Pipelines	4.8	0.4
Prince Rupert Gas Transmission	Canadian Natural Gas Pipelines	5.0	0.5
NGTL System - Merrick	Canadian Natural Gas Pipelines	1.9	—
		45.2	2.3
Foreign exchange impact on medium to longer-term projects[4]		2.8	0.1
Total medium to longer-term projects (billions of Cdn$)		**48.0**	**2.4**

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 $1.33 at March 31, 2017.

Outlook

Our overall comparable earnings outlook for 2017 remains consistent with what was previously included in the 2016 Annual Report.

Consolidated acquisition, equity investments and capital spending

Our expected total capital expenditures 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 March 31	
(unaudited - millions of $)	**2017**	**2016**
NGTL System	**230**	226
Canadian Mainline	**247**	231
Other Canadian pipelines[1]	**28**	32
Business development	**(1)**	(1)
Comparable EBITDA	**504**	488
Depreciation and amortization	**(222)**	(216)
Comparable EBIT and segmented earnings	**282**	272

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

Canadian Natural Gas Pipelines segmented earnings increased by $10 million for the three months ended March 31, 2017 compared to the same period 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 March 31	
(unaudited - millions of $)	**2017**	**2016**
NGTL System	**82**	73
Canadian Mainline	**52**	50

Net income for the NGTL System increased by $9 million for the three months ended March 31, 2017 compared to the same period in 2016 mainly due to a higher average investment base and OM&A incentive earnings recorded 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 increased by $2 million for the three months ended March 31, 2017 compared to the same period in 2016 primarily due to higher incentive earnings, partially offset by a lower average investment base. 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 $6 million for the three months ended March 31, 2017 compared to the same period in 2016 mainly due to the NGTL System facilities that were placed in service.

OPERATING STATISTICS - NGTL SYSTEM AND CANADIAN MAINLINE

three months ended March 31	NGTL System[1]		Canadian Mainline[2]	
(unaudited)	**2017**	**2016**	**2017**	**2016**
Average investment base (millions of $)	**7,853**	7,257	**4,103**	4,384
Delivery volumes (Bcf):				
Total	**1,090**	1,063	**521**	481
Average per day	**12.1**	11.7	**5.8**	5.3

1 Field receipt volumes for the NGTL System for the three months ended March 31, 2017 were 1,037 Bcf (2016 – 1,074 Bcf). Average per day was 11.5 Bcf (2016 – 11.8 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 three months ended March 31, 2017 were 235 Bcf (2016 – 274 Bcf). Average per day was 2.6 Bcf (2016 – 3.0 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 March 31	
(unaudited - millions of US$, unless otherwise noted)	**2017**	**2016**
Columbia Gas[1]	**185**	—
ANR	**122**	87
TC PipeLines, LP[2,3]	**32**	31
Great Lakes[3,4]	**27**	25
Midstream[1]	**23**	—
Columbia Gulf[1]	**18**	—
Other U.S. pipelines[1,2,3,5]	**29**	14
Non-controlling interests[6]	**108**	95
Business development	**(1)**	(1)
Comparable EBITDA	**543**	251
Depreciation and amortization	**(112)**	(51)
Comparable EBIT	**431**	200
Foreign exchange impact	**140**	71
Comparable EBIT (Cdn$)	**571**	271
Specific items:		
Acquisition related costs - Columbia	**(10)**	—
TC Offshore loss on sale	**—**	(4)
Segmented earnings (Cdn$)	**561**	267

1 We completed the acquisition of Columbia on July 1, 2016 and the remaining 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.

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 GTN, Great Lakes and PNGTS through our ownership interest in TC PipeLines, LP for the periods presented.

	Effective ownership percentage as of	
	March 31, 2017	**March 31, 2016**
TC PipeLines, LP	26.4	27.9
Effective ownership through TC PipeLines, LP:		
Great Lakes	12.3	13.0
PNGTS	13.2	13.9

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 direct ownership in Iroquois and PNGTS and our effective ownership in Millennium and Hardy Storage.

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 $294 million for the three months ended March 31, 2017 compared to the same period in 2016 primarily due to the acquisition of Columbia and included a $10 million pre-tax charge, primarily due to integration-related costs associated with the Columbia acquisition. Segmented earnings for the three months ended March 31, 2016 included a $4 million pre-tax loss provision ($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.

Earnings for 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$292 million for the three months ended March 31, 2017 compared to the same period in 2016 and was the net effect of:

- US$250 million of earnings as a result of the acquisition of Columbia on July 1, 2016 and the remaining publicly held common units of CPPL on February 17, 2017
- higher ANR transportation revenue resulting from a FERC-approved rate settlement, effective August 1, 2016, and higher storage results.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US$61 million for the three months ended March 31, 2017 compared to the same period in 2016 mainly due to the acquisition of Columbia.

US$5 million of 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-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 March 31	
(unaudited - millions of US$, unless otherwise noted)	**2017**	**2016**
Topolobampo	**40**	(1)
Tamazunchale	**29**	27
Guadalajara	**17**	17
Mazatlán	**16**	—
Sur de Texas[1]	**4**	—
Other	**—**	(1)
Business development	**—**	(3)
Comparable EBITDA	**106**	39
Depreciation and amortization	**(17)**	(6)
Comparable EBIT	**89**	33
Foreign exchange impact	**29**	12
Comparable EBIT and segmented earnings (Cdn$)	**118**	45

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 $73 million for the three months ended March 31, 2017 compared to the same period in 2016 and are equivalent to comparable EBIT.

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$67 million for the three months ended March 31, 2017 compared to the same period in 2016 and was the net effect of:

- US$41 million 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
- US$16 million of incremental earnings from Mazatlán. Construction is complete and the collection and recognition of revenue began per the terms of the TSA in December 2016
- US$4 million of 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$11 million for the three months ended March 31, 2017 compared to the same period 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 March 31	
(unaudited - millions of $)	**2017**	**2016**
Keystone Pipeline System	**306**	302
Business development and other	**6**	(6)
Comparable EBITDA	**312**	296
Depreciation and amortization	**(77)**	(72)
Comparable EBIT	**235**	224
Specific items:		
Keystone XL asset costs	**(8)**	(10)
Risk management activities	**—**	(2)
Segmented earnings	**227**	212
Comparable EBIT denominated as follows:		
Canadian dollars	**55**	53
U.S. dollars	**135**	127
Foreign exchange impact	**45**	44
	235	224

Liquids Pipelines segmented earnings increased by $15 million for the three months ended March 31, 2017 compared to the same period in 2016 and included pre-tax charges related to Keystone XL costs for the maintenance of project assets which are being expensed pending further advancement of the project as well as unrealized losses from changes in the fair value of derivatives related to our liquids marketing business in 2016.

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 $16 million for the three months ended March 31, 2017 compared to the same period in 2016 and was the net effect of:

- higher volumes on Keystone pipeline
- higher contribution from liquids marketing
- higher business development activities, including advancement of Keystone XL.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $5 million for the three months ended March 31, 2017 compared to the same period in 2016 as a result of new facilities being placed in service.

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 March 31	
(unaudited - millions of $)	**2017**	**2016**
Canadian Power		
Western Power[1]	**30**	4
Eastern Power	**94**	102
Bruce Power	**91**	114
Canadian Power - comparable EBITDA[1,2]	**215**	220
Depreciation and amortization	**(37)**	(47)
Canadian Power - comparable EBIT[1,2]	**178**	173
U.S. Power (US$)		
U.S. Power - comparable EBITDA	**54**	75
Depreciation and amortization[3]	**—**	(31)
U.S. Power - comparable EBIT	**54**	44
Foreign exchange impact	**18**	17
U.S. Power - comparable EBIT (Cdn$)	**72**	61
Natural Gas Storage and other - comparable EBITDA	**21**	9
Depreciation and amortization	**(3)**	(3)
Natural Gas Storage and other - comparable EBIT	**18**	6
Business Development comparable EBITDA and EBIT	**(3)**	(3)
Energy - comparable EBIT[1,2]	**265**	237
Specific items:		
U.S. Northeast power monetization	**(11)**	—
Alberta PPA terminations	**—**	(240)
Risk management activities	**(56)**	(123)
Segmented earnings/(losses)[1,2]	**198**	(126)

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 Depreciation no longer being recorded effective November 1, 2016 on assets held for sale.

Energy segmented earnings increased by $324 million for the three months ended March 31, 2017 compared to the same period in 2016 and included the following specific items:

- in 2017, $11 million of pre-tax costs related to the monetization of our U.S. Northeast power business. 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 March 31**	
(unaudited - millions of $, pre-tax)	**2017**	**2016**
Canadian Power	**1**	(13)
U.S. Power	**(62)**	(115)
Natural Gas Storage	**5**	5
Total unrealized losses from risk management activities	**(56)**	(123)

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.

	three months ended March 31	
(unaudited - millions of $)	2017	2016
Revenue[1]		
Western Power	**46**	88
Eastern Power	**105**	95
Other[2]	**15**	29
	166	212
Income from equity investments[3]	**8**	—
Commodity purchases resold	**(1)**	(59)
Plant operating costs and other	**(49)**	(47)
Comparable EBITDA[4]	**124**	106
Depreciation and amortization	**(37)**	(47)
Comparable EBIT[4]	**87**	59
Breakdown of comparable EBITDA		
Western Power[4]	**30**	4
Eastern Power	**94**	102
Comparable EBITDA[4]	**124**	106
Plant availability[5]		
Western Power	**99%**	99%
Eastern Power[6,7]	**99%**	86%

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 Includes our share of equity income in Portlands Energy, and ASTC Power Partnership up to March 7, 2016.

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

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

6 Does not include Bécancour because power generation has been suspended since 2008.

7 Plant availability was higher in the three months ended March 31, 2017 than the same period in 2016 due to an unplanned outage at the Halton Hills facility in 2016.

Western Power

Comparable EBITDA for Western Power increased by $26 million for the three months ended March 31, 2017 compared to the same period in 2016 mainly due to the termination of the Alberta PPAs. 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 three months ended March 31, 2017 compared to the same period in 2016 following the termination of the Alberta PPAs.

Eastern Power

Comparable EBITDA for Eastern Power decreased by $8 million for the three months ended March 31, 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 March 31	
(unaudited - millions of $, unless noted otherwise)	**2017**	**2016**
Equity income included in comparable EBITDA and EBIT comprised of:		
Revenues	**401**	415
Operating expenses	**(224)**	(225)
Depreciation and other	**(86)**	(76)
Comparable EBITDA and EBIT[1]	**91**	114
Bruce Power - other information		
Plant availability[2]	**89%**	88%
Planned outage days	**56**	76
Unplanned outage days	**17**	8
Sales volumes (GWh)[1]	**5,983**	5,834
Realized sales price per MWh[3]	**$67**	$66

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 decreased by $23 million for the three months ended March 31, 2017 compared to the same period in 2016 mainly due to lower gains from contracting activities and higher interest expense, partially offset by higher volumes resulting from fewer outage days.

Planned outage work which commenced on Unit 5 in February 2017 is scheduled to be completed in second quarter 2017. Planned outages for Units 3 and 6 are scheduled to occur in the 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 $12 million for the three months ended March 31, 2017 compared to the same period in 2016 mainly due to increased third party storage revenues as a result of higher realized natural gas storage price spreads.

U.S. POWER (monetization expected to close in the first half of 2017)

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

	three months ended March 31	
(unaudited - millions of US$)	2017	2016
Revenue[1]		
Power[2]	**530**	418
Capacity	**42**	62
	572	480
Commodity purchases resold	**(409)**	(305)
Plant operating costs and other[3]	**(109)**	(100)
Comparable EBITDA[1]	**54**	75
Depreciation and amortization[4]	**—**	(31)
Comparable EBIT[1]	**54**	44

1 Includes Ironwood commencing February 1, 2016.
2 Includes the realized gains and losses from financial derivatives used to manage U.S. Power's assets 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.
3 Includes the cost of fuel consumed in generation.
4 U.S. Power assets held for sale are no longer being depreciated effective November 2016.

Sales volumes and plant availability

	three months ended March 31	
(unaudited)	2017	2016
Physical sales volumes (GWh)		
Supply		
Generation	**2,007**	2,280
Purchased	**6,356**	4,748
	8,363	7,028
Plant availability[1]	**71%**	71%

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

U.S. Power - other information

	three months ended March 31	
(unaudited)	2017	2016
Average Spot Power Prices (US$ per MWh)		
New England[1]	**36**	30
New York[2]	**36**	28
PJM[3]	**29**	21
Average New York[2] Spot Capacity Prices (US$ per KW-M)	**3.43**	5.83

1 New England ISO all hours Mass Hub price.
2 Zone J market in New York City where the Ravenswood plant operates.
3 The METED Zone price in Pennsylvania where the Ironwood plant operates. Average price for 2016 is from the Ironwood acquisition date of February 1, 2016.

Comparable EBITDA for U.S. Power decreased by US$21 million for the three months ended March 31, 2017 compared to the same period in 2016 and was the net effect of:

- lower realized capacity prices in New York
- higher realized power prices at our facilities in New York and New England, partially offset by higher fuel costs and lower generation volumes
- higher sales to customers in the PJM and New England wholesale utility markets offset by lower realized margins.

Average New York Zone J spot capacity prices were approximately 41 per cent lower for the three months ended March 31, 2017 compared to the same period in 2016. The decrease in spot capacity prices and the offsetting impact of hedging activities resulted in lower realized capacity prices in New York. This was primarily due to an increase in demonstrated capability from existing resources in the New York City's Zone J market.

Physical purchased volumes sold to wholesale, commercial and industrial customers were higher for the three months ended March 31, 2017 than the same period in 2016 as we have expanded our customer base in the PJM and New England 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 March 31	
(unaudited - millions of $)	**2017**	**2016**
Comparable EBITDA and EBIT	**(4)**	(1)
Specific items:		
Acquisition related costs - Columbia	**(29)**	(26)
Segmented losses	**(33)**	(27)

Corporate segmented losses increased by $6 million for the three months ended March 31, 2017 compared to the same period in 2016. Comparable EBIT in 2017 and 2016 excluded acquisition and integration costs associated with the acquisition of Columbia.

OTHER INCOME STATEMENT ITEMS

Interest expense

	three months ended March 31	
(unaudited - millions of $)	**2017**	**2016**
Interest on long-term debt and junior subordinated notes		
Canadian dollar-denominated	**(108)**	(111)
U.S. dollar-denominated	**(317)**	(246)
Foreign exchange impact	**(103)**	(85)
	(528)	(442)
Other interest and amortization expense	**(17)**	(19)
Capitalized interest	**45**	41
Interest expense	**(500)**	(420)

Interest expense increased by $80 million for the three months ended March 31, 2017 compared to the same period in 2016 and was the net effect of debt assumed in the acquisition of Columbia on July 1, 2016 and long-term debt issuances, partially offset by Canadian and U.S. dollar-denominated debt maturities.

Allowance for funds used during construction

(unaudited - millions of $)	three months ended March 31 2017	2016
Canadian dollar-denominated	**50**	41
U.S. dollar-denominated	**38**	45
Foreign exchange impact	**13**	15
Allowance for funds used during construction	**101**	101

AFUDC was consistent for the three months ended March 31, 2017 compared to the same period in 2016. The increase in Canadian dollar-denominated AFUDC is primarily due to increased investment in our NGTL System expansions, while the decrease in our U.S. dollar-denominated AFUDC is primarily due to the completed construction of Topolobampo and Mazatlán pipelines, partially offset by our increased investment in projects acquired as part of the Columbia acquisition on July 1, 2016.

Interest income and other

(unaudited - millions of $)	three months ended March 31 2017	2016
Interest income and other included in comparable earnings	**5**	47
Specific item:		
Risk management activities	**15**	53
Interest income and other	**20**	100

Interest income and other decreased by $80 million for the three months ended March 31, 2017 compared to the same period in 2016 and was the net effect of:

- 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
- lower unrealized gains on risk management activities in 2017 compared to 2016. These amounts have been excluded from comparable earnings
- the impact of a fluctuating U.S. dollar on the translation of foreign currency denominated working capital.

Income tax expense

(unaudited - millions of $)	three months ended March 31 2017	2016
Income tax expense included in comparable earnings	**(244)**	(180)
Specific items:		
Acquisition related costs - Columbia	**15**	—
U.S. Northeast power monetization	**1**	—
Keystone XL income tax recoveries	**7**	—
Keystone XL asset costs	**1**	4
Alberta PPA terminations	**—**	64
TC Offshore loss on sale	**—**	1
Risk management activities	**20**	41
Income tax expense	**(200)**	(70)

Income tax expense included in comparable earnings increased by $64 million for the three months ended March 31, 2017 compared to the same period 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 March 31 2017	2016
Net income attributable to non-controlling interests	**(90)**	(80)

Net income attributable to non-controlling interests increased by $10 million for the three months ended March 31, 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 outstanding publicly held common units of CPPL.

Preferred share dividends

(unaudited - millions of $)	three months ended March 31 2017	2016
Preferred share dividends	**(41)**	(22)

Preferred share dividends increased by $19 million for the three months ended March 31, 2017 compared to the same period 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

The NGTL System currently has a $5.1 billion near-term capital program for completion to 2020. This includes the recently filed application to amend approvals for the North Montney project, with a revised $1.4 billion capital cost estimate, and the recently approved Towerbirch Expansion project.

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, but still accommodates, 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 and included the request to implement the service starting November 1, 2017.

U.S. NATURAL GAS PIPELINES

Sale of Iroquois and PNGTS to TC PipeLines, LP

On May 4, 2017, we announced agreements to sell a 49.3 per cent interest in Iroquois Gas Transmission System, LP (Iroquois), together with our remaining 11.8 per cent interest in Portland Natural Gas Transmission System (PNGTS), to our master limited partnership, TC PipeLines, LP for US$765 million. The transaction is comprised of US$597 million in cash and the assumption of US$168 million in proportionate debt at Iroquois and PNGTS. The transaction is expected to close mid-2017.

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$1.4 billion Leach XPress project and the US$0.4 billion Rayne XPress project are expected to be in service in November 2017.

WB XPress

We received our Environmental Assessment on March 24, 2017 for the WB XPress project and expect to receive our FERC order later this summer after additional FERC Commissioners are appointed and a quorum is re-established. The US$0.8 billion project remains on schedule with Phase I expected to be in-service in June 2018 and Phase II in November 2018.

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 Pipeline

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, however, 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, however, a hearing date has not yet been announced by the NEB.

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.

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 expect this transition to be complete within a few months and would anticipate commercial support for the project to be substantially similar to that which existed when we first applied for Keystone XL.

ENERGY

U.S. Power

Ravenswood

In late March 2017, the 972 MW Unit 30 at the Ravenswood Generating Station experienced an unplanned outage as a result of a problem on the generator associated with the low pressure turbine. Repairs to the unit are underway and the unit is expected to be returned to service in second quarter 2017. The incident is not expected to materially affect the sale process for Ravenswood.

Monetization of U.S. Northeast power business

The sale of TC Hydro to Great River Hydro, LLC closed on April 19, 2017 for proceeds of US$1.065 billion resulting in a gain of approximately $710 million ($440 million after tax) before post-closing adjustments which will be recorded in second quarter 2017. The proceeds received were used to reduce the Columbia acquisition bridge credit facility.

The sale of Ravenswood, Ironwood, Ocean State Power and Kibby to Helix Generation, LLC is expected to close in second quarter 2017.

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 the establishment of an at-the-market equity issuance program, if applicable), our DRP, portfolio management including proceeds from the anticipated drop down of natural gas pipeline assets to TC PipeLines, LP, cash on hand and substantial committed credit facilities.

At March 31, 2017, our current assets were $8.0 billion and current liabilities were $9.1 billion, leaving us with a working capital deficit of $1.1 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 $9.1 billion of unutilized, unsecured committed credit facilities.

CASH PROVIDED BY OPERATING ACTIVITIES

	three months ended March 31	
(unaudited - millions of $, except per share amounts)	**2017**	**2016**
Net cash provided by operations	**1,302**	1,081
Increase in operating working capital	**155**	132
Funds generated from operations[1]	**1,457**	1,213
Specific items:		
Acquisition related costs - Columbia	**32**	26
Keystone XL asset costs	**8**	10
U.S. Northeast power monetization	**11**	—
Comparable funds generated from operations[1]	**1,508**	1,249
Dividends on preferred shares	**(39)**	(23)
Distributions paid to non-controlling interests	**(80)**	(62)
Maintenance capital expenditures including equity investments	**(167)**	(190)
Comparable distributable cash flow[1]	**1,222**	974
Comparable distributable cash flow per common share	**$1.41**	$1.39

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

COMPARABLE FUNDS GENERATED FROM OPERATIONS

Comparable funds generated from operations increased $259 million for the three months ended March 31, 2017 compared to the same period 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 first quarter 2016 to 2017 was driven by an increase in comparable funds generated from operations and lower maintenance capital expenditures, primarily at Bruce Power, partially offset by higher dividends on preferred shares and distributions paid to non-controlling interests. Comparable distributable cash flow per share in 2017 included 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 March 31	
(unaudited - millions of $)	**2017**	**2016**
Canadian Natural Gas Pipelines	**49**	55
U.S. Natural Gas Pipelines	**70**	71
Other	**48**	64
Maintenance capital expenditures including equity investments	**167**	190

CASH USED IN INVESTING ACTIVITIES

	three months ended March 31	
(unaudited - millions of $)	**2017**	**2016**
Capital spending		
Capital expenditures	**(1,560)**	(836)
Capital projects in development	**(42)**	(67)
	(1,602)	(903)
Contributions to equity investments	**(192)**	(170)
Acquisitions, net of cash acquired	**—**	(995)
Proceeds from sale of assets, net of transaction costs	**—**	6
Other distributions from equity investments	**363**	—
Deferred amounts and other	**(85)**	52
Net cash used in investing activities	**(1,516)**	(2,010)

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
- expansion of the ANR pipeline
- construction of the Napanee power generating facility.

Costs incurred on capital projects under 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.

The increase in other distributions from equity investments is primarily due to distributions from Bruce Power. In first quarter 2017, Bruce Power issued bonds to fund its capital program and make distributions to its partners which resulted in $362 million being received by us.

CASH PROVIDED BY FINANCING ACTIVITIES

	three months ended March 31	
(unaudited - millions of $)	**2017**	**2016**
Notes payable issued, net	**670**	1,176
Long-term debt issued, net of issue costs	**—**	1,992
Long-term debt repaid	**(1,051)**	(1,357)
Junior subordinated notes issued, net of issue costs	**1,982**	—
Dividends and distributions paid	**(419)**	(450)
Common shares issued, net of issue costs	**18**	3
Common shares repurchased	**—**	(14)
Partnership units of TC PipeLines, LP issued, net of issue costs	**92**	24
Common units of Columbia Pipeline Partners LP acquired	**(1,205)**	—
Net cash provided by financing activities	**87**	1,374

On February 17, 2017, we acquired all outstanding common units of CPPL for US$921 million.

LONG-TERM DEBT RETIRED/REPAID

(unaudited - millions of $) Company	Retirement/ Repayment date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	February 2017	Acquisition Bridge Facility[1]	US $500	Floating
	January 2017	Medium Term Notes	$300	5.10%
TRANSCANADA PIPELINE USA LTD				
	April 2017	Acquisition Bridge Facility[1,2]	US $1,070	Floating

1 This facility was put into place to finance a portion of the Columbia acquisition and bears interest at LIBOR plus an applicable margin.

2 Proceeds from the April 19, 2017 sale of TC Hydro were used to partially repay the acquisition bridge facility.

JUNIOR SUBORDINATED NOTES ISSUED

(unaudited - millions of $) Company	Issue date	Type	Maturity date	Amount	Interest rate
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 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. In the most recent quarter, approximately 40 per cent of common share dividends declared were designated to be reinvested by shareholders in TransCanada common shares under the DRP.

TC PIPELINES, LP AT-THE-MARKET (ATM) EQUITY ISSUANCE PROGRAM

During first quarter 2017, 1.2 million common units were issued under the TC PipeLines, LP ATM program generating net proceeds of approximately US$69 million. At March 31, 2017, our ownership interest in TC PipeLines, LP was 26.4 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. In March 2017, rescission rights on 0.4 million common units expired. No unitholder has claimed or attempted to exercise any rescission rights to date and these rights expire one year from the date of purchase of the unit.

DIVIDENDS

On May 4, 2017, we declared quarterly dividends as follows:

Quarterly dividend on our common shares
$0.625 per share
Payable on July 31, 2017 to shareholders of record at the close of business on June 30, 2017

Quarterly dividends on our preferred shares	
Series 1	$0.204125
Series 2	$0.14958904
Series 3	$0.1345
Series 4	$0.10969863
Payable on June 30, 2017 to shareholders of record at the close of business on May 31, 2017	
Series 5	$0.14143750
Series 6	$0.12796096
Series 7	$0.25
Series 9	$0.265625
Payable on July 31, 2017 to shareholders of record at the close of business on June 30, 2017	
Series 11	$0.2375
Series 13	$0.34375
Series 15	$0.30625
Payable on May 31, 2017 to shareholders of record at the close of business on May 16, 2017	

SHARE INFORMATION

as at May 1, 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**
	12 million	8 million

CREDIT FACILITIES

We have several committed credit facilities that support our commercial paper programs and provide short-term liquidity for general corporate purposes as well as acquisition bridge facilities to support the interim financing of the Columbia acquisition. 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 May 4, 2017, we had a total of $11.1 billion of committed revolving and demand credit facilities and $2.8 million of acquisition bridge 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 commercial paper program and for general corporate purposes	December 2021
US$1.5 billion	—	TCPL	Committed, syndicated, senior asset bridge term loan commitment that supports the acquisition of Columbia	June 2018
US$2.0 billion	US$2.0 billion	TCPL	Committed, syndicated, revolving, extendible credit facility that supports TCPL's U.S. commercial paper program	December 2017
US$0.6 billion	—	TCPL USA	Committed, syndicated, senior asset bridge term loan commitment that supports the acquisition of Columbia	June 2018
US$1.0 billion	US$1.0 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$0.5 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	TAIL	Committed, syndicated, revolving, extendible credit facility that supports TAIL's 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 May 4, 2017, our operated affiliates had an additional $0.7 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 $0.5 billion since December 31, 2016 primarily as a result of decreased commitments for the NGTL System and Sur de Texas natural gas pipelines due to the progression of construction. Transportation by others commitments have increased by approximately $0.7 billion since December 31, 2016, primarily related to Canadian Mainline contracts.

Our commitments at March 31, 2017 include operating leases and other purchase obligations related to our U.S. Northeast power business. At the close of the sale of Ravenswood, Ironwood, Kibby Wind and Ocean State Power, our commitments are expected to decrease by $42 million in 2017, $97 million in 2018, $79 million in 2019, $29 million in 2020, $23 million in 2021 and $259 million in 2022 and beyond.

There were no other material changes to our contractual obligations in first 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.

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
- notes receivable.

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At March 31, 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.

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 March 31, 2017	**1.32**
three months ended March 31, 2016	1.35

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 March 31	
(unaudited - millions of US$)	**2017**	**2016**
U.S. Natural Gas Pipelines comparable EBIT	**431**	200
Mexico Natural Gas Pipelines comparable EBIT	**89**	33
U.S. Liquids Pipelines comparable EBIT	**135**	127
U.S. Power comparable EBIT	**54**	44
AFUDC on U.S. dollar-denominated projects	**38**	45
Interest on U.S. dollar-denominated long-term debt	**(317)**	(246)
Capitalized interest on U.S. dollar-denominated capital expenditures	**—**	7
U.S. dollar non-controlling interests	**(68)**	(60)
	362	150

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:

	March 31, 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]	**(337)**	**US 2,000**	(425)	US 2,350
U.S. dollar foreign exchange forward contracts	**—**	**—**	(7)	US 150
	(337)	**US 2,000**	(432)	US 2,500

1 Fair values equal carrying values.

2 In the three months ended March 31, 2017, net realized gains of $1 million (2016 - gains of $2 million) 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)	March 31, 2017	December 31, 2016
Notional amount	**28,400 (US 21,400)**	26,600 (US 19,800)
Fair value	**31,500 (US 23,600)**	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 $)	March 31, 2017	December 31, 2016
Other current assets	**413**	376
Intangible and other assets	**153**	133
Accounts payable and other	**(607)**	(607)
Other long-term liabilities	**(334)**	(330)
	(375)	(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 March 31	
(unaudited - millions of $, pre-tax)	2017	2016
Derivative instruments held for trading[1]		
Amount of unrealized (losses)/gains in the period		
Commodities[2]	**(56)**	(67)
Foreign exchange	**15**	27
Interest rate	**1**	—
Amount of realized (losses)/gains in the period		
Commodities	**(48)**	(95)
Foreign exchange	**(4)**	44
Derivative instruments in hedging relationships		
Amount of realized gains/(losses) in the period		
Commodities	**6**	(73)
Foreign exchange	**5**	(63)
Interest rate	**1**	2

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 March 31	
(unaudited - millions of $, pre-tax)	**2017**	**2016**
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Commodities	**5**	(16)
Foreign exchange	**—**	(35)
Interest rate	**1**	(3)
	6	(54)
Reclassification of (losses)/gains on derivative instruments from AOCI to net income (effective portion)[1]		
Commodities[2]	**(4)**	82
Foreign exchange[3]	**—**	34
Interest rate[4]	**4**	4
	—	120
Losses on derivative instruments recognized in net income (ineffective portion)		
Commodities[2]	**—**	(58)
	—	(58)

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 March 31, 2017, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $20 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 March 31, 2017, we would have been required to provide additional collateral of $20 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 March 31, 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.

There were no changes in first 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 update 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 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. This new guidance was effective January 1, 2017, was applied prospectively and did not result 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. In these situations, when an increase in ownership interest in an investment qualifies it for equity method accounting, the new guidance eliminates the requirement to retroactively apply the equity method of accounting. This new guidance was effective January 1, 2017, was applied prospectively and did not result 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, on a prospective basis, January 1, 2017 and resulted in a cumulative-effect adjustment of $12 million to 2017 opening retained earnings and the recognition of a deferred tax asset related to employee share-based payments made prior to the adoption of this standard.

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 variable interest entity (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 are evaluating both methods of adoption as we work through our analysis.

We have identified all existing customer contracts that are within the scope of the new guidance and we are in the process of analyzing individual contracts or groups of contracts on a segmented basis to identify any significant changes in how revenues are recognized as a result of implementing the new standard. As we continue our contract analysis, we will also quantify the impact, if any, on prior period revenues. We will address any system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new standard. We are currently evaluating the impact on our consolidated financial statements as well as the development of disclosures required under the new standard.

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 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 specifies the method of adoption 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 the arrangement to qualify as a lease. The new guidance requires lessees to recognize most leases, including operating leases, on the balance sheet as lease assets and lease liabilities. Lessees may also be required to reassess assumptions associated with existing leases as well as to provide expanded qualitative and quantitative disclosures. The new standard does not make extensive changes to lessor accounting. The new guidance is effective January 1, 2019. We are currently identifying existing lease agreements that may have an impact on our consolidated financial statements as a result of adopting this 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 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 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 on a modified retrospective basis. 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, and amounts generally described as restricted cash or restricted cash equivalents. The amounts of restricted cash and cash equivalents will be included in 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 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, with early adoption 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 the 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 the 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 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 March 31	
(unaudited - millions of $)	**2017**	**2016**
Comparable EBITDA		
Canadian Natural Gas Pipelines	**504**	488
U.S. Natural Gas Pipelines	**720**	338
Mexico Natural Gas Pipelines	**140**	53
Liquids Pipelines	**312**	296
Energy	**305**	328
Corporate	**(4)**	(1)
Comparable EBITDA	**1,977**	1,502
Depreciation and amortization	**(510)**	(454)
Comparable EBIT	**1,467**	1,048
Specific items:		
Acquisition related costs - Columbia	**(39)**	(26)
U.S. Northeast power monetization	**(11)**	—
Keystone XL asset costs	**(8)**	(10)
Alberta PPA terminations	**—**	(240)
TC Offshore loss on sale	**—**	(4)
Risk management activities[1]	**(56)**	(125)
Segmented earnings	**1,353**	643

1

Risk management activities	three months ended March 31	
(unaudited - millions of $)	**2017**	**2016**
Canadian Power	**1**	(13)
U.S. Power	**(62)**	(115)
Natural Gas Storage	**5**	5
Liquids marketing	**—**	(2)
Total unrealized losses from risk management activities	**(56)**	(125)

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

	2017	2016				2015		
(unaudited - millions of $, except per share amounts)	First	Fourth	Third	Second	First	Fourth	Third	Second
Revenues	**3,391**	3,619	3,632	2,751	2,503	2,851	2,944	2,631
Net income/(loss) attributable to common shares	**643**	(358)	(135)	365	252	(2,458)	402	429
Comparable earnings	**698**	626	622	366	494	453	440	397
Per share statistics								
Net income/(loss) per common share - basic and diluted	**$0.74**	($0.43)	($0.17)	$0.52	$0.36	($3.47)	$0.57	$0.60
Comparable earnings per share	**$0.81**	$0.75	$0.78	$0.52	$0.70	$0.64	$0.62	$0.56
Dividends declared per common share	**$0.625**	$0.565	$0.565	$0.565	$0.565	$0.52	$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 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.

In second quarter 2015, comparable earnings excluded a $34 million adjustment to income tax expense due to the enactment of an increase in the Alberta corporate income tax rate in June 2015 and a charge of $8 million after-tax for severance costs primarily as a result of the restructuring of our major projects group in response to delayed timelines on certain of our major projects along with a continued focus on enhancing the efficiency and effectiveness of our operations.

Condensed consolidated statement of income

	three months ended March 31	
(unaudited - millions of Canadian $, except per share amounts)	**2017**	**2016**
Revenues		
Canadian Natural Gas Pipelines	**882**	818
U.S. Natural Gas Pipelines	**994**	429
Mexico Natural Gas Pipelines	**143**	66
Liquids Pipelines	**472**	436
Energy	**900**	754
	3,391	2,503
Income from Equity Investments	**174**	135
Operating and Other Expenses		
Plant operating costs and other	**990**	715
Commodity purchases resold	**543**	470
Property taxes	**162**	141
Depreciation and amortization	**517**	454
Asset impairment charges	**—**	211
	2,212	1,991
Loss on sale of assets	**—**	(4)
Financial Charges		
Interest expense	**500**	420
Allowance for funds used during construction	**(101)**	(101)
Interest income and other	**(20)**	(100)
	379	219
Income before Income Taxes	**974**	424
Income Tax Expense		
Current	**67**	34
Deferred	**133**	36
	200	70
Net Income	**774**	354
Net income attributable to non-controlling interests	**90**	80
Net Income Attributable to Controlling Interests	**684**	274
Preferred share dividends	**41**	22
Net Income Attributable to Common Shares	**643**	252
Net Income per Common Share		
Basic and diluted	**$0.74**	$0.36
Dividends Declared per Common Share	**$0.625**	$0.565
Weighted Average Number of Common Shares (millions)		
Basic	**866**	702
Diluted	**868**	703

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

	three months ended March 31	
(unaudited - millions of Canadian $)	**2017**	**2016**
Net Income	**774**	354
Other Comprehensive Loss, Net of Income Taxes		
Foreign currency translation losses on net investment in foreign operations	**(82)**	(212)
Change in fair value of net investment hedges	**(1)**	(2)
Change in fair value of cash flow hedges	**5**	(39)
Reclassification to net income of gains on cash flow hedges	**—**	80
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**3**	4
Other comprehensive income on equity investments	**3**	3
Other comprehensive loss (Note 9)	**(72)**	(166)
Comprehensive Income	**702**	188
Comprehensive income/(loss) attributable to non-controlling interests	**50**	(26)
Comprehensive Income Attributable to Controlling Interests	**652**	214
Preferred share dividends	**41**	22
Comprehensive Income Attributable to Common Shares	**611**	192

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of cash flows

	three months ended March 31	
(unaudited - millions of Canadian $)	**2017**	**2016**
Cash Generated from Operations		
Net income	**774**	354
Depreciation and amortization	**517**	454
Asset impairment charges	**—**	211
Deferred income taxes	**133**	36
Income from equity investments	**(174)**	(135)
Distributions received from operating activities of equity investments	**219**	259
Employee post-retirement benefits expense, net of funding	**3**	11
Loss on sale of assets	**—**	4
Equity allowance for funds used during construction	**(64)**	(57)
Unrealized losses on financial instruments	**41**	71
Other	**8**	5
Increase in operating working capital	**(155)**	(132)
Net cash provided by operations	**1,302**	1,081
Investing Activities		
Capital expenditures	**(1,560)**	(836)
Capital projects in development	**(42)**	(67)
Contributions to equity investments	**(192)**	(170)
Acquisitions, net of cash acquired	**—**	(995)
Proceeds from sale of assets, net of transaction costs	**—**	6
Other distributions from equity investments	**363**	—
Deferred amounts and other	**(85)**	52
Net cash used in investing activities	**(1,516)**	(2,010)
Financing Activities		
Notes payable issued, net	**670**	1,176
Long-term debt issued, net of issue costs	**—**	1,992
Long-term debt repaid	**(1,051)**	(1,357)
Junior subordinated notes issued, net of issue costs	**1,982**	—
Dividends on common shares	**(300)**	(365)
Dividends on preferred shares	**(39)**	(23)
Distributions paid to non-controlling interests	**(80)**	(62)
Common shares issued, net of issue costs	**18**	3
Common shares repurchased	**—**	(14)
Partnership units of TC PipeLines, LP issued, net of issue costs	**92**	24
Common units of Columbia Pipeline Partners LP acquired	**(1,205)**	—
Net cash provided by financing activities	**87**	1,374
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**5**	(57)
(Decrease)/increase in Cash and Cash Equivalents	**(122)**	388
Cash and Cash Equivalents		
Beginning of period	**1,016**	850
Cash and Cash Equivalents		
End of period	**894**	1,238

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		March 31, 2017	December 31, 2016
ASSETS			
Current Assets			
Cash and cash equivalents		**894**	1,016
Accounts receivable		**2,120**	2,075
Inventories		**384**	368
Assets held for sale		**3,687**	3,717
Other		**918**	908
		8,003	8,084
Plant, Property and Equipment	net of accumulated depreciation of $22,696 and $22,263, respectively	**55,353**	54,475
Equity Investments		**6,262**	6,544
Regulatory Assets		**1,325**	1,322
Goodwill		**13,849**	13,958
Intangible and Other Assets		**3,148**	3,026
Restricted Investments		**699**	642
		88,639	88,051
LIABILITIES			
Current Liabilities			
Notes payable		**1,493**	774
Accounts payable and other		**3,806**	3,861
Dividends payable		**557**	526
Accrued interest		**549**	595
Liabilities related to assets held for sale		**60**	86
Current portion of long-term debt		**2,669**	1,838
		9,134	7,680
Regulatory Liabilities		**2,259**	2,121
Other Long-Term Liabilities		**1,134**	1,183
Deferred Income Tax Liabilities		**7,749**	7,662
Long-Term Debt		**36,163**	38,312
Junior Subordinated Notes		**5,879**	3,931
		62,318	60,889
Common Units Subject to Rescission or Redemption		**82**	1,179
EQUITY			
Common shares, no par value		**20,308**	20,099
Issued and outstanding:	March 31, 2017 - 867 million shares		
	December 31, 2016 - 864 million shares		
Preferred shares		**3,980**	3,980
Additional paid-in capital		**—**	—
Retained earnings		**1,115**	1,138
Accumulated other comprehensive loss		**(992)**	(960)
Controlling Interests		**24,411**	24,257
Non-controlling interests		**1,828**	1,726
		26,239	25,983
		88,639	88,051

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

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of equity

	three months ended March 31	
(unaudited - millions of Canadian $)	**2017**	**2016**
Common Shares		
Balance at beginning of period	**20,099**	12,102
Shares issued on exercise of stock options	**19**	3
Shares repurchased	**—**	(6)
Shares issued under dividend reinvestment and share purchase plan	**190**	—
Balance at end of period	**20,308**	12,099
Preferred Shares		
Balance at beginning and end of period	**3,980**	2,499
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	**10**	3
Impact of common shares repurchased	**—**	(8)
Impact of asset drop down to TC PipeLines, LP	**—**	(38)
Impact of Columbia Pipeline Partners LP acquisition	**(171)**	—
Reclassification of Additional Paid-In Capital deficit to Retained Earnings	**159**	31
Balance at end of period	**—**	—
Retained Earnings		
Balance at beginning of period	**1,138**	2,769
Net income attributable to controlling interests	**684**	274
Common share dividends	**(542)**	(397)
Preferred share dividends	**(18)**	(21)
Adjustment related to employee share-based payments (Note 2)	**12**	—
Reclassification of Additional Paid-In Capital deficit to Retained Earnings	**(159)**	(31)
Balance at end of period	**1,115**	2,594
Accumulated Other Comprehensive Loss		
Balance at beginning of period	**(960)**	(939)
Other comprehensive loss	**(32)**	(60)
Balance at end of period	**(992)**	(999)
Equity Attributable to Controlling Interests	**24,411**	16,193
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	**73**	71
Portland Natural Gas Transmission System	**8**	9
Columbia Pipeline Partners LP	**9**	—
Other comprehensive loss attributable to non-controlling interests	**(40)**	(106)
Issuance of TC PipeLines, LP units		
Proceeds, net of issue costs	**92**	24
Decrease in TransCanada's ownership of TC PipeLines, LP	**(17)**	(4)
Reclassification from common units subject to rescission	**24**	—
Distributions declared to non-controlling interests	**(80)**	(68)
Impact of Columbia Pipeline Partners LP acquisition	**33**	—
Balance at end of period	**1,828**	1,643
Total Equity	**26,239**	17,836

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 update 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 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. This new guidance was effective January 1, 2017, was applied prospectively and did not result 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. In these situations, when an increase in ownership interest in an investment qualifies it for equity method accounting, the new guidance eliminates the requirement to retroactively apply the equity method of accounting. This new guidance was effective January 1, 2017, was applied prospectively and did not result 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 standard.

Consolidation

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

FUTURE ACCOUNTING CHANGES

Revenue from contracts with customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. The new guidance requires that an entity recognize revenue in accordance with a 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 is evaluating both methods of adoption as it works through its analysis.

The Company has identified all existing customer contracts that are within the scope of the new guidance and is in the process of analyzing individual contracts or groups of contracts on a segmented basis to identify any significant changes in how revenues are recognized as a result of implementing the new standard. As the Company continues its contract analysis, it will also quantify the impact, if any, on prior period revenues. The Company will address any system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new standard. The Company is currently evaluating the impact on its consolidated financial statements as well as the development of disclosures required under the new standard.

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 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 specifies the method of adoption 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 the arrangement to qualify as a lease. The new guidance requires lessees to recognize most leases, including operating leases, on the balance sheet as lease assets and lease liabilities. Lessees may also be required to reassess assumptions associated with existing leases as well as to provide expanded qualitative and quantitative disclosures. The new standard does not make extensive changes to lessor accounting. The new guidance is effective January 1, 2019. The Company is currently identifying existing lease agreements that may have an impact on its consolidated financial statements as a result of adopting this 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 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 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, and amounts generally described as restricted cash or restricted cash equivalents. The amounts of restricted cash and cash equivalents will be included in 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 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, with early adoption 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 the 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 the 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 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 March 31, 2017 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**882**	**994**	**143**	**472**	**900**	**—**	**3,391**
Income from equity investments	**3**	**65**	**6**	**—**	**100**	**—**	**174**
Plant operating costs and other	**(312)**	**(295)**	**(9)**	**(145)**	**(196)**	**(33)**	**(990)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(543)**	**—**	**(543)**
Property taxes	**(69)**	**(47)**	**—**	**(23)**	**(23)**	**—**	**(162)**
Depreciation and amortization	**(222)**	**(156)**	**(22)**	**(77)**	**(40)**	**—**	**(517)**
Segmented earnings/(losses)	**282**	**561**	**118**	**227**	**198**	**(33)**	**1,353**
Interest expense							**(500)**
Allowance for funds used during construction							**101**
Interest income and other							**20**
Income before income taxes							**974**
Income tax expense							**(200)**
Net income							**774**
Net income attributable to non-controlling interests							**(90)**
Net income attributable to controlling interests							**684**
Preferred share dividends							**(41)**
Net income attributable to common shares							**643**

three months ended March 31, 2016 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	818	429	66	436	754	—	2,503
Income from equity investments	3	48	—	—	84	—	135
Plant operating costs and other	(260)	(118)	(13)	(129)	(168)	(27)	(715)
Commodity purchases resold	—	—	—	—	(470)	—	(470)
Property taxes	(73)	(21)	—	(23)	(24)	—	(141)
Depreciation and amortization	(216)	(67)	(8)	(72)	(91)	—	(454)
Asset impairment charges	—	—	—	—	(211)	—	(211)
Loss on assets held for sale	—	(4)	—	—	—	—	(4)
Segmented earnings/(losses)	272	267	45	212	(126)	(27)	643
Interest expense							(420)
Allowance for funds used during construction							101
Interest income and other							100
Income before income taxes							424
Income tax expense							(70)
Net Income							354
Net income attributable to non-controlling interests							(80)
Net Income attributable to controlling interests							274
Preferred share dividends							(22)
Net Income attributable to common shares							252

TOTAL ASSETS

(unaudited - millions of Canadian $)	March 31, 2017	December 31, 2016
Canadian Natural Gas Pipelines	**16,255**	15,816
U.S. Natural Gas Pipelines	**34,934**	34,422
Mexico Natural Gas Pipelines	**5,230**	5,013
Liquids Pipelines	**16,995**	16,896
Energy	**12,832**	13,169
Corporate	**2,393**	2,735
	88,639	88,051

4. Assets held for sale

U.S. Northeast Power Assets

The Company's planned monetization of its U.S. Northeast power business, for the purpose of permanently financing a portion of the Columbia acquisition, includes the sale of Ravenswood, Ironwood, Kibby Wind, Ocean State Power, TC Hydro and the marketing business, TransCanada Power Marketing (TCPM).

On November 1, 2016, the Company entered into agreements to sell all of these assets except TCPM.

The sale of Ravenswood, Ironwood, Kibby Wind and Ocean State Power to a third party for proceeds of approximately US$2.2 billion is expected to close in the second quarter of 2017. As a result, the Company recorded a loss of approximately $829 million ($863 million after tax) in 2016 which included the impact of an estimated $70 million of foreign currency translation gains to be reclassified from AOCI to Net income on close. At March 31, 2017, the related assets and liabilities were classified as held for sale in the Energy segment and were recorded at their fair values less costs to sell based on the proceeds expected on the close of this sale.

At March 31, 2017, the assets and liabilities related to TC Hydro were also classified as held for sale in the Energy segment. Subsequently, on April 19, 2017, the Company closed the sale of TC Hydro for gross proceeds of US$1.065 billion, subject to post-closing adjustments. As a result, on April 19, 2017, the Company recorded a gain on sale of approximately $710 million ($440 million after tax) including the impact of an estimated $5 million of foreign currency translation gains. The proceeds received were used to reduce the outstanding balance on the acquisition bridge facility.

As of March 31, 2017, TCPM did not meet the criteria to be classified as held for sale.

The following table details the assets and liabilities held for sale at March 31, 2017.

(millions of $)	U.S.	Canadian[1]
Assets held for sale		
Accounts receivable	**10**	**13**
Inventories	**56**	**74**
Other current assets	**73**	**97**
Plant, property and equipment	**2,242**	**2,986** [2]
Intangible and other assets	**335**	**447**
Foreign currency translation gains	**—**	**70** [3]
Total assets held for sale	**2,716**	**3,687**
Liabilities related to assets held for sale		
Accounts payable and other	**21**	**28**
Other long-term liabilities	**24**	**32**
Total liabilities related to assets held for sale	**45**	**60**

1 At March 31, 2017 exchange rate of $1.33.
2 Includes $17 million (US$13 million) for a gas plant held for sale in the U.S. Natural Gas Pipelines segment.
3 Foreign currency translation gains related to the investments in Ravenswood, Ironwood, Kibby Wind and Ocean State Power will be reclassified from AOCI to Net Income on close of the sales.

5. Income taxes

The effective tax rates for the three-month periods ended March 31, 2017 and 2016 were 21 per cent and 17 per cent, respectively. The higher effective tax rate in 2017 was primarily the result of changes in the proportion of income earned between Canadian and foreign jurisdictions.

6. Long-term debt

LONG-TERM DEBT RETIRED/REPAID

The Company retired/repaid long-term debt in the three months ended March 31, 2017 as follows:

(unaudited - millions of Canadian $, unless noted otherwise) **Company**	**Retirement/ Repayment date**	**Type**	**Amount**	**Interest rate**
TRANSCANADA PIPELINES LIMITED				
	February 2017	Acquisition Bridge Facility[1]	US$500	Floating
	January 2017	Medium Term Notes	$300	5.10%

1 This facility was put into place to finance a portion of the Columbia acquisition and bears interest at LIBOR plus an applicable margin.

In the three months ended March 31, 2017, TransCanada capitalized interest related to capital projects of $45 million (2016 - $41 million).

7. Junior subordinated notes issued

(unaudited - millions of Canadian $, unless noted otherwise) **Company**	**Issue date**	**Type**	**Maturity date**	**Amount**	**Interest rate**
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 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.

8. 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 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

At March 31, 2017, $82 million (US$63 million) (December 31, 2016 - $106 million (US$82 million)) was recorded as Common units subject to rescission or redemption on the condensed consolidated balance sheet. In March 2017, rescission rights on 0.4 million TC PipeLines, LP common units expired and $24 million was reclassified to equity. The Company continued to classify $82 million with respect to 1.2 million common units outside Equity because the potential rescission rights of the units are not within the control of the Company. At March 31, 2017, no unitholder has claimed or attempted to exercise any rescission rights to date and these remaining rescission rights expire one year from the date of purchase of the units which ranges from April 1, 2016 to May 19, 2016.

9. 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 March 31, 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	**(88)**	**6**	**(82)**
Change in fair value of net investment hedges	**(2)**	**1**	**(1)**
Change in fair value of cash flow hedges	**6**	**(1)**	**5**
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**5**	**(2)**	**3**
Other comprehensive income on equity investments	**4**	**(1)**	**3**
Other comprehensive loss	**(75)**	**3**	**(72)**

three months ended March 31, 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	(210)	(2)	(212)
Change in fair value of net investment hedges	(3)	1	(2)
Change in fair value of cash flow hedges	(54)	15	(39)
Reclassification to net income of gains on cash flow hedges	120	(40)	80
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	5	(1)	4
Other comprehensive income on equity investments	4	(1)	3
Other comprehensive loss	(138)	(28)	(166)

The changes in AOCI by component are as follows:

three months ended March 31, 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]	**(42)**	**4**	**—**	**—**	**(38)**
Amounts reclassified from accumulated other comprehensive loss	**—**	**—**	**3**	**3**	**6**
Net current period other comprehensive (loss)/ income[3]	**(42)**	**4**	**3**	**3**	**(32)**
AOCI balance at March 31, 2017	**(418)**	**(24)**	**(205)**	**(345)**	**(992)**

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 $41 million and gains of $1 million.

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 $2 million ($1 million, net of tax) at March 31, 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:

(unaudited - millions of Canadian $)	Amounts reclassified from accumulated other comprehensive loss[1] three months ended March 31 2017	2016	Affected line item in the condensed consolidated statement of income
Cash flow hedges			
Commodities	**4**	(82)	Revenue (Energy)
Foreign exchange	**—**	(34)	Interest income and other
Interest rate	**(4)**	(4)	Interest expense
	—	(120)	Total before tax
	—	40	Income tax expense
	—	(80)	Net of tax
Pension and other post-retirement benefit plan adjustments			
Amortization of actuarial loss	**(4)**	(5)	Plant operating costs[2]
	2	1	Income tax expense
	(2)	(4)	Net of tax
Equity investments			
Equity income	**(4)**	(4)	Income from equity investments
	1	1	Income tax expense
	(3)	(3)	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 10 for additional detail.

10. 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 March 31			
	Pension benefit plans		Other post-retirement benefit plans	
(unaudited - millions of Canadian $)	**2017**	**2016**	**2017**	**2016**
Service cost	**29**	26	**1**	1
Interest cost	**34**	30	**4**	2
Expected return on plan assets	**(50)**	(40)	**(5)**	—
Amortization of actuarial loss	**4**	4	**—**	1
Amortization of regulatory asset	**6**	4	**—**	—
Net benefit cost recognized	**23**	24	**—**	4

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.

11. 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 March 31, 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, notes, 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 March 31, 2017, there were no significant amounts past due or impaired, no significant credit risk concentration and no significant credit losses during the period.

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)	**March 31, 2017**	**December 31, 2016**
Notional amount	**28,400 (US 21,400)**	26,600 (US 19,800)
Fair value	**31,500 (US 23,600)**	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:

	March 31, 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]	**(337)**	**US 2,000**	(425)	US 2,350
U.S. dollar foreign exchange forward contracts	**—**	**—**	(7)	US 150
	(337)	**US 2,000**	(432)	US 2,500

1 Fair values equal carrying values.

2 In the three months ended March 31, 2017, net realized gains of $1 million (2016 - gains of $2 million) 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 the Company's Notes receivable is calculated by discounting future payments of interest and principal using forward interest rates. 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:

	March 31, 2017		December 31, 2016	
(unaudited - millions of Canadian $)	Carrying amount	Fair value	Carrying amount	Fair value
Notes receivable[1]	**115**	**158**	165	211
Current and long-term debt[2,3]	**(38,832)**	**(43,770)**	(40,150)	(45,047)
Junior subordinated notes	**(5,879)**	**(6,021)**	(3,931)	(3,825)
	(44,596)	**(49,633)**	(43,916)	(48,661)

1 Notes receivable are included in Assets held for sale on the condensed consolidated balance sheet. The fair value is 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 months ended March 31, 2017 included unrealized gains of $2 million (2016 - losses of $12 million) 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 March 31, 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:

	March 31, 2017		December 31, 2016	
(unaudited - millions of Canadian $)	LMCI restricted investments	Other restricted investments[2]	LMCI restricted investments	Other restricted investments[2]
Fair Values[1]				
Fixed income securities (maturing within 1 year)	**—**	**27**	—	19
Fixed income securities (maturing within 1-5 years)	**—**	**106**	—	117
Fixed income securities (maturing within 5-10 years)	**13**	**—**	9	—
Fixed income securities (maturing after 10 years)	**572**	**—**	513	—
	585	**133**	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.

	March 31, 2017		March 31, 2016	
(unaudited - millions of Canadian $)	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	**2**	**—**	5	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 March 31, 2017 is as follows:

at March 31, 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]	**9**	**—**	**—**	**387**	**396**
Foreign exchange	**—**	**—**	**4**	**9**	**13**
Interest rate	**2**	**—**	**—**	**2**	**4**
	11	**—**	**4**	**398**	**413**
Intangible and other assets					
Commodities[2]	**3**	**—**	**—**	**141**	**144**
Foreign exchange	**—**	**—**	**8**	**—**	**8**
Interest rate	**1**	**—**	**—**	**—**	**1**
	4	**—**	**8**	**141**	**153**
Total Derivative Assets	**15**	**—**	**12**	**539**	**566**
Accounts payable and other					
Commodities[2]	**—**	**—**	**—**	**(373)**	**(373)**
Foreign exchange	**—**	**—**	**(209)**	**(22)**	**(231)**
Interest rate	**(1)**	**(2)**	**—**	**—**	**(3)**
	(1)	**(2)**	**(209)**	**(395)**	**(607)**
Other long-term liabilities					
Commodities[2]	**(1)**	**—**	**—**	**(192)**	**(193)**
Foreign exchange	**—**	**—**	**(140)**	**—**	**(140)**
Interest rate	**—**	**(1)**	**—**	**—**	**(1)**
	(1)	**(1)**	**(140)**	**(192)**	**(334)**
Total Derivative Liabilities	**(2)**	**(3)**	**(349)**	**(587)**	**(941)**
Total Derivatives	**13**	**(3)**	**(337)**	**(48)**	**(375)**

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 March 31, 2017 (unaudited)	Power	Natural Gas	Liquids	Foreign Exchange	Interest
Purchases[1]	**104,858**	**222**	**12**	**—**	**—**
Sales[1]	**66,420**	**202**	**14**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**US 2,513**	**US 2,600**
Millions of Mexican pesos	**—**	**—**	**—**	**MXN 500**	**—**
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 March 31	
(unaudited - millions of Canadian $)	2017	2016
Derivative instruments held for trading[1]		
Amount of unrealized (losses)/gains in the period		
Commodities[2]	**(56)**	(67)
Foreign exchange	**15**	27
Interest rate	**1**	—
Amount of realized (losses)/gains in the period		
Commodities	**(48)**	(95)
Foreign exchange	**(4)**	44
Derivative instruments in hedging relationships		
Amount of realized gains/(losses) in the period		
Commodities	**6**	(73)
Foreign exchange	**5**	(63)
Interest rate	**1**	2

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 9) related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests are as follows:

	three months ended March 31	
(unaudited - millions of Canadian $, pre-tax)	**2017**	**2016**
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Commodities	**5**	(16)
Foreign exchange	**—**	(35)
Interest rate	**1**	(3)
	6	(54)
Reclassification of (losses)/gains on derivative instruments from AOCI to net income (effective portion)[1]		
Commodities[2]	**(4)**	82
Foreign exchange[3]	**—**	34
Interest rate[4]	**4**	4
	—	120
Losses on derivative instruments recognized in net income (ineffective portion)		
Commodities[2]	**—**	(58)
	—	(58)

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 March 31, 2017 (unaudited - millions of Canadian $)	**Gross derivative instruments presented on the balance sheet**	**Amounts available for offset[1]**	**Net amounts**
Derivative - Asset			
Commodities	**540**	**(333)**	**207**
Foreign exchange	**21**	**(20)**	**1**
Interest rate	**5**	**(2)**	**3**
Total	**566**	**(355)**	**211**
Derivative - Liability			
Commodities	**(566)**	**333**	**(233)**
Foreign exchange	**(371)**	**20**	**(351)**
Interest rate	**(4)**	**2**	**(2)**
Total	**(941)**	**355**	**(586)**

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 March 31, 2017, the Company provided cash collateral of $310 million (December 31, 2016 - $305 million) and letters of credit of $22 million (December 31, 2016 - $27 million) to its counterparties. The Company held nil (December 31, 2016 - nil) in cash collateral and $3 million (December 31, 2016 - $3 million) in letters of credit from counterparties on asset exposures at March 31, 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 March 31, 2017, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $20 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 March 31, 2017, the Company would have been required to provide additional collateral of $20 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 March 31, 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	**82**	**433**	**25**	**540**
Foreign exchange	**—**	**21**	**—**	**21**
Interest rate	**—**	**5**	**—**	**5**
Derivative instrument liabilities:				
Commodities	**(64)**	**(487)**	**(15)**	**(566)**
Foreign exchange	**—**	**(371)**	**—**	**(371)**
Interest rate	**—**	**(4)**	**—**	**(4)**
	18	**(403)**	**10**	**(375)**

1 There were no transfers from Level I to Level II or from Level II to Level III for the three months ended March 31, 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 March 31	
(unaudited - millions of Canadian $)	**2017**	**2016**
Balance at beginning of period	**16**	9
Transfers out of Level III	**(4)**	(3)
Sales	**(2)**	(1)
Settlements	**—**	1
Total gains included in net income	**—**	3
Balance at end of period[1]	**10**	9

1 For the three months ended March 31, 2017, revenues include unrealized losses of less than $1 million attributed to derivatives in the Level III category that were still held at March 31, 2017 (2016 - gains of $2 million).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a less than $1 million change in the fair value of outstanding derivative instruments included in Level III as at March 31, 2017.

12. Commitments, contingencies and guarantees

COMMITMENTS

TransCanada's operating lease commitments at March 31, 2017 include future payments related to our U.S. Northeast power business. At the close of the sale of Ravenswood, TransCanada's commitments are expected to decrease by $3 million in 2017, $53 million in 2018, $35 million in 2019 and $105 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 March 31, 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	**758**	**10**	805	53
Bruce Power	ranging to 2018	**88**	**1**	88	1
Other jointly owned entities	ranging to 2059	**111**	**16**	87	28
		957	**27**	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 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 $)	March 31, 2017	December 31, 2016
ASSETS		
Current Assets		
Cash and cash equivalents	**92**	77
Accounts receivable	**62**	71
Inventories	**24**	25
Other	**7**	10
	185	183
Plant, Property and Equipment	**3,627**	3,685
Equity Investments	**595**	606
Goodwill	**521**	525
Intangible and Other Assets	**1**	1
	4,929	5,000
LIABILITIES		
Current Liabilities		
Accounts payable and other	**94**	80
Accrued interest	**22**	21
Current portion of long-term debt	**72**	76
	188	177
Regulatory Liabilities	**34**	34
Other Long-Term Liabilities	**4**	4
Deferred Income Tax Liabilities	**7**	7
Long-Term Debt	**2,723**	2,827
	2,956	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 $)	March 31, 2017	December 31, 2016
Balance sheet		
Equity investments	**4,642**	4,964
Off-balance sheet		
Potential exposure to guarantees	**176**	163
Maximum exposure to loss	**4,818**	5,127

14. Subsequent events

U.S. Northeast Power Assets

TC Hydro
On April 19, 2017, the Company closed the sale of TC Hydro for gross proceeds of US$1.065 billion, subject to post-closing adjustments. The proceeds received were used to reduce the Columbia acquisition bridge credit facility. Refer to Note 4, Assets held for sale, for further information.

Sale of Iroquois and PNGTS to TC PipeLines, LP
On May 4, 2017, the Company announced agreements to sell a 49.3 per cent interest in Iroquois Gas Transmission System, LP (Iroquois), together with its remaining 11.8 per cent interest in Portland Natural Gas Transmission System (PNGTS), to its master limited partnership, TC PipeLines, LP for US$765 million. The transaction is comprised of US$597 million in cash and the assumption of US$168 million in proportionate debt at Iroquois and PNGTS. The transaction is expected to close mid-2017.