QuarterlyReport to Shareholders

TransCanada
In business to deliver

TransCanada Reports Solid Third Quarter 2017 Financial Results
Diversified, Low-Risk Business Strategy Continues to Drive Performance

CALGARY, Alberta – **November 9, 2017** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced net income attributable to common shares for third quarter 2017 of $612 million or $0.70 per share compared to a net loss of $135 million or $0.17 per share for the same period in 2016. Comparable earnings for third quarter 2017 were $614 million or $0.70 per share compared to $622 million or $0.78 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 December 31, 2017, equivalent to $2.50 per common share on an annualized basis.

"During the third quarter of 2017, our diversified portfolio of high-quality, long-life energy infrastructure assets continued to perform very well," said Russ Girling, TransCanada's president and chief executive officer. "While comparable earnings are lower compared to the same quarter in 2016, the reduction is largely attributable to completing the sale of our U.S. Northeast Power generation portfolio in second quarter 2017. Over the first nine months of this year, financial performance has been very strong with comparable earnings per share increasing 12 per cent compared to the same period in 2016. Looking forward, we anticipate continued solid financial performance as over 95 per cent of our earnings before interest, taxes, depreciation and amortization (EBITDA) is expected to come from regulated or long-term contracted assets."

"In the third quarter, we continued to advance our near-term capital program by placing the Grand Rapids pipeline into service. In addition, we continue to progress $24 billion of other near-term capital projects that are 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. "We have invested approximately $10 billion into these projects to date and are well positioned to fund the remainder of this capital program over the next few years through our strong internally generated cash flow and access to capital markets on compelling terms. To date in the fourth quarter we have recovered approximately $0.6 billion of development costs associated with the Prince Rupert Gas Transmission project and agreed to sell our Ontario solar portfolio for approximately $540 million. The proceeds will be used to fund a portion of our capital program and for general corporate purposes."

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

Highlights

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

- Third quarter 2017 financial results
  - Net income attributable to common shares of $612 million or $0.70 per share
  - Comparable earnings of $614 million or $0.70 per share
  - Comparable earnings before interest, taxes, depreciation and amortization of $1.7 billion
  - Net cash provided by operations of $1.2 billion
  - Comparable funds generated from operations of $1.3 billion
  - Comparable distributable cash flow of $769 million or $0.88 per common share

- Declared a quarterly dividend of $0.625 per common share for the quarter ending December 31, 2017
- Placed the $0.9 billion Grand Rapids pipeline in service
- Received approval from Canada's National Energy Board (NEB) to commence service on the Canadian Mainline long-term fixed price service effective November 1, 2017
- After careful review of changed circumstances, announced the termination of Energy East and related projects and expect an estimated $1 billion after-tax non-cash charge will be recorded in fourth quarter 2017
- In October, received $0.6 billion related to development costs and carrying charges on the Prince Rupert Gas Transmission (PRGT) project following Progress Energy's decision to terminate their agreement with us
- Raised $1 billion in proceeds through a Canadian offering of Medium Term Notes maturing in 2028 and 2047
- On October 25, announced an agreement to sell our Ontario solar portfolio for approximately $540 million with proceeds to be used to partially fund our near-term capital program. The transaction is expected to result in an estimated $100 million after-tax gain to be recognized upon closing
- In November, the $1 billion Northern Courier pipeline achieved commercial in-service, and we placed the US$0.4 billion Rayne XPress pipeline and the US$0.3 billion Gibraltar project in service. We expect to bring the US$1.6 billion Leach XPress project in service in early January 2018
- Advanced the Portland XPress and Buckeye XPress projects to move additional gas across our pipeline network

Net income attributable to common shares increased by $747 million to $612 million or $0.70 per share for the three months ended September 30, 2017 compared to the same period last year. Net income per common share in third quarter 2017 includes the dilutive effect of issuing 60 million common shares in fourth quarter 2016. Third quarter 2017 results included an additional $12 million after-tax net loss on sales of U.S. Northeast Power assets, an after-tax charge of $30 million for integration-related costs associated with the acquisition of Columbia and an $8 million after-tax charge related to the maintenance of Keystone XL assets. Third quarter 2016 included a $656 million after-tax goodwill impairment charge, an after-tax charge of $67 million related to costs associated with the acquisition of Columbia, recognition of $28 million of income tax recoveries resulting from a third party sale of Keystone XL project assets, a $9 million after-tax charge related to Keystone XL maintenance and liquidation costs and $3 million of after-tax costs related to the sale of our U.S. Northeast Power business. All of these specific items as well as unrealized gains and losses from changes in risk management activities, are excluded from comparable earnings.

Comparable earnings for third quarter 2017 were $614 million or $0.70 per share compared to $622 million or $0.78 per share for the same period in 2016, a decrease of $8 million or $0.08 per share. Comparable earnings per share for the three months ended September 30, 2017 include the dilutive effect of issuing 60 million common shares in fourth quarter 2016. The decrease in third quarter comparable earnings was primarily due to the net effect of the monetization of our U.S. Northeast Power generation assets in second quarter 2017 and a lower contribution from U.S. Natural Gas Pipelines primarily due to the timing of funding contributions to the Columbia Gas defined benefit pension plan, partially offset by higher ANR transportation revenues resulting from a Federal Energy Regulatory Commission (FERC)-approved rate settlement, effective August 1, 2016, higher AFUDC on our rate-regulated U.S. Natural Gas Pipelines, lower interest expense mainly due to the repayment of the remaining bridge facilities that partially funded the acquisition of Columbia, higher interest income and other primarily due to realized gains in 2017 compared to realized losses in 2016 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and income recognized on the termination of the PRGT project, higher contribution from Liquids Pipelines primarily due to higher Keystone volumes and the commencement of operations on Grand Rapids, higher earnings from Bruce Power mainly due to improved results from contracting activities, and a higher contribution from Mexico Natural Gas Pipelines primarily due to earnings from Mazatlán beginning in December 2016, partially offset by the impairment of our equity investment in TransGas.

Notable recent developments include:

Canadian Natural Gas Pipelines:

- ***Canadian Mainline:*** On September 21, 2017, the NEB approved the long-term fixed price (LTFP) service, as filed, with an effective date of November 1, 2017. This new service allows us to transport 1.5 PJ/d (1.4 Bcf/d) of natural gas at a simplified toll of $0.77/GJ for a ten year term from the Alberta / Saskatchewan border to the Dawn Hub in southern Ontario and provides shippers with toll certainty and improved market access.
- ***NGTL System***: In March 2017, we filed an application with the NEB for a variance to the existing approvals for the North Montney project on the NGTL System to remove the condition that the project could only proceed once a positive final investment decision is made for the Pacific Northwest LNG project (PNW LNG). North Montney is now under-pinned by restructured, 20-year commercial contracts with shippers and is not dependent on the LNG project proceeding. On September 7, 2017, the NEB provided notice that a public hearing process would be used to consider our variance application. The NEB also stated it would consider the continued appropriateness and applicability of the tolling decisions and associated conditions of the original approval. On October 26, 2017, the NEB issued the Hearing Order indicating the oral portion of the hearing will begin the week of January 22, 2018 with a decision to follow within 12 weeks after the hearing conclusion.
- ***Prince Rupert Gas Transmission:*** In July 2017, we were notified that PNW LNG would not be proceeding with their proposed LNG project and that Progress Energy (Progress) would be terminating their agreement with us for development of the PRGT project, effective August 10, 2017. In accordance with the terms of the agreement, all project costs incurred to advance the project, including carrying charges, are fully recoverable upon termination. As a result, we received a payment of $0.6 billion from Progress in October 2017.

U.S. Natural Gas Pipelines:

- ***Rayne XPress:*** Rayne Xpress was placed in service November 2, 2017. This Columbia Gulf project will transport approximately 1.1 PJ/d (1.0 Bcf/d) of supply from an interconnect with the Leach XPress pipeline project, and another interconnect, to markets along the system and to the Gulf Coast.
- ***Midstream:*** The Gibraltar Midstream project, a 1,000 TJ/d (934 MMcf/d) dry gas header pipeline in southwest Pennsylvania, was placed in service November 1, 2017.
- ***Leach XPress:*** The Leach XPress project is expected to have a US$100 million increase in its capital project cost due to delays caused by weather on the project's construction schedule and the resulting increase in contractor costs. Leach XPress is expected to be placed in service in early January 2018.
- ***FERC Update:*** The FERC regained a quorum of three commissioners in August 2017 and two additional commissioners were approved by the U.S. Senate on November 2, 2017. The FERC has stated that it intends to expeditiously address the resulting backlog of pending applications. We expect the FERC certificates for the WB XPress, Mountaineer XPress and Gulf XPress projects to be received in fourth quarter 2017.
- ***Mountaineer XPress:*** The Mountaineer XPress project is expected to have a US$600 million increase in its capital project cost due to increased construction cost estimates. As a result of a cost sharing mechanism, overall project returns are not anticipated to be materially affected. Mountaineer XPress is expected to be placed in service in fourth quarter 2018.
- ***Buckeye Xpress:*** The Buckeye XPress project (BXP) represents an up-sizing of an existing pipeline replacement project under our Columbia Gas modernization program. The US$0.2 billion cost to up-size the replacement pipe and install compressor upgrades will enable us to offer 290 TJ/d (275 MMcf/d) of incremental pipeline capacity to accommodate growing Appalachian production. We expect BXP to be placed in service in late 2020.

- *Portland XPress Project:* PNGTS has executed Precedent Agreements with several local distribution companies (LDCs) in New England and Atlantic Canada to re-contract certain system capacity set to expire in 2019, as well as expand the PNGTS system to bring its certificated capacity up to 280 TJ/d (265 MMcf/d). The approximately US$80 million Portland XPress Project (PXP) will proceed concurrently with upstream capacity expansions. The in-service dates of PXP are being phased-in over a three year period beginning November 1, 2018.
- *Great Lakes impact from Canadian Mainline's LTFP:* In conjunction with the Canadian Mainline's LTFP service, Great Lakes entered into a new 10-year gas transportation contract with the Canadian Mainline. This contract received NEB approval in September 2017 and became effective on November 1, 2017. This contract contains volume reduction options up to full contract quantity beginning in year three.
- *Great Lakes Rate Case:* On October 30, 2017, Great Lakes filed a rate settlement with the FERC to satisfy its obligations from its 2013 rate settlement for new rates to be in effect by January 1, 2018. The 2017 Great Lakes Settlement, if approved by the FERC, will decrease Great Lakes' maximum transportation rates by 27 per cent beginning October 1, 2017. Great Lakes expects that the impact from other changes, including the recent long-term transportation contract with the Canadian Mainline as described above, other revenue opportunities on the system and the elimination of the revenue sharing mechanism with its customers, will more than offset the full year impact of the reduction in Great Lakes' rates beginning in 2018. The 2017 Great Lakes Settlement does not contain any moratorium and Great Lakes will be required to file for new rates no later than March 31, 2022, with new rates to be effective October 1, 2022.
- *Northern Border:* Northern Border and its shippers have been engaged in settlement discussions, and have recently agreed to a settlement-in-principle addressing all rate and service related issues raised during the settlement discussions. Northern Border plans to file a settlement agreement with the FERC before the end of the year, reflecting the settlement-in-principle, precluding the need to file a general rate case as contemplated by its 2012 Settlement. Northern Border anticipates that the FERC will accept the settlement agreement and that it will be unopposed. This will provide Northern Border with rate stability over the longer term. At this time, we do not believe that the final outcome of the settlement will have a material impact on our consolidated results. We have a 13 per cent indirect ownership interest in Northern Border through TC PipeLines, LP.

Liquids Pipelines:

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

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

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

- *Keystone XL:* Given the passage of time since the Keystone XL Presidential Permit application was previously denied in November 2015, we are updating the shipping contracts and anticipate the core contract shipper group will be modified with the introduction of new shippers and reductions in volume commitments by other shippers. We anticipate commercial support for the project to be substantially similar to that which existed when we first applied for a Keystone XL pipeline permit.

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

  In February 2017, we filed an application with the Nebraska Public Service Commission (PSC) seeking approval for the Keystone XL pipeline route through that state. In August 2017, the Nebraska PSC concluded the public hearing for the Keystone XL pipeline and final written submissions were submitted in September 2017. The Nebraska PSC will review all comments gathered from the public meetings, the written submissions and the hearing before making a final decision on the route permit which is expected by the end of November 2017.
- *Grand Rapids:* In late August 2017, the Grand Rapids pipeline, jointly owned by TransCanada and PetroChina Canada Ltd., was placed in service. The 460 km (287 mile) pipeline plays a key role in connecting producing areas northwest of Fort McMurray, Alberta, to terminals in the Edmonton / Heartland region.
- *Northern Courier:* Northern Courier, a 90 km (56 mile) pipeline which transports bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta, achieved commercial in-service on November 1, 2017.

Energy:

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

Corporate:

- *Common Share Dividend:* Our Board of Directors declared a quarterly dividend of $0.625 per share for the quarter ending December 31, 2017 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $2.50 per common share on an annualized basis.
- *Medium Term Note Issuance:* In September 2017, TransCanada issued $1 billion of Medium Term Notes comprised of $300 million of 10.5-year notes at an interest rate of 3.39 per cent and $700 million of 30-year notes at an interest rate of 4.33 per cent.
- *Dividend Reinvestment Plan (DRP):* To date in 2017, the participation rate in our DRP has been approximately 36 per cent of common share dividends, resulting in $594 million of common equity issued under the program year-to-date.
- *ATM Equity Issuance Program:* In June 2017, we established an At-The-Market (ATM) equity issuance program that allows us to issue common shares from treasury having an aggregate gross sales price of up to $1.0 billion or their U.S. dollar equivalent, from time to time, at our discretion, at the prevailing market price when sold through the Toronto Stock Exchange or the New York Stock Exchange. The ATM program, which is effective for a 25-month period, will be activated at our discretion, if and as required, based on the spend profile of TransCanada’s capital program and relative cost of other funding options. At September 30, 2017, no common shares had been issued under the program.

Teleconference and Webcast:

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

Members of the investment community and other interested parties are invited to participate by calling 800.898.3989 or 416.406.0743 (Toronto area) and enter passcode 5745518#. Please dial in 10 minutes prior to the start of the call. 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 November 16, 2017. Please call 800.408.3053 or 905.694.9451 (Toronto area) and enter pass code 7183649#.

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

With more than 65 years' experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and liquids pipelines, power generation and gas storage facilities. TransCanada operates a network of natural gas pipelines that extends more than 91,500 kilometres (56,900 miles), tapping into virtually all major gas supply basins in North America. TransCanada is the continent's largest provider of gas storage and related services with 653 billion cubic feet of storage capacity. A large independent power producer, TransCanada owns or has interests in approximately 6,200 megawatts of power generation in Canada and the United States. TransCanada is also the developer and operator of one of North America's leading liquids pipeline systems that extends approximately 4,800 kilometres (3,000 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 November 8, 2017 and the 2016 Annual Report to shareholders 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 November 8, 2017.

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Quarterly report to shareholders

Third quarter 2017

Financial highlights

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $, except per share amounts)	**2017**	**2016**	**2017**	**2016**
Income				
Revenues	**3,242**	3,632	**9,850**	8,886
Net income/(loss) attributable to common shares	**612**	(135)	**2,136**	482
per common share - basic	**$0.70**	($0.17)	**$2.46**	$0.66
- diluted	**$0.70**	($0.17)	**$2.45**	$0.66
Comparable EBITDA[1]	**1,667**	1,886	**5,474**	4,757
Comparable earnings[1]	**614**	622	**1,971**	1,482
per common share[1]	**$0.70**	$0.78	**$2.27**	$2.02
Cash flows				
Net cash provided by operations	**1,185**	1,265	**3,840**	3,494
Comparable funds generated from operations[1]	**1,316**	1,441	**4,191**	3,746
Comparable distributable cash flow[1]	**769**	994	**2,872**	2,613
per common share[1]	**$0.88**	$1.25	**$3.30**	$3.56
Capital spending - capital expenditures	**2,031**	1,444	**5,383**	3,262
- projects in development	**37**	62	**135**	219
- contributions to equity investments	**475**	286	**1,140**	570
Acquisitions, net of cash acquired	**—**	12,609	**—**	13,608
Proceeds from sales of assets, net of transaction costs	**—**	—	**4,147**	6
Dividends declared				
Per common share	**$0.625**	$0.565	**$1.875**	$1.695
Basic common shares outstanding (millions)				
Average for the period	**873**	797	**870**	734
End of period	**874**	800	**874**	800

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

November 8, 2017

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

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

FORWARD-LOOKING INFORMATION

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

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

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

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

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

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

Assumptions

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

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

Risks and uncertainties

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

You can read more about these factors and others in reports we have filed with Canadian securities regulators and the SEC, including the MD&A in our 2016 Annual Report.

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

FOR MORE INFORMATION

You can find more information about 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 GAAP and therefore may not be similar to measures presented by other entities.

Comparable measures

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

Our decision to adjust for a specific item is subjective and made after careful consideration. Specific items may include:

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

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

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

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

Comparable earnings and comparable earnings per common share

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

Comparable EBIT and comparable EBITDA

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

Funds generated from operations and comparable funds generated from operations

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

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

We believe comparable distributable cash flow is a useful supplemental measure of performance that defines cash available to common shareholders before capital allocation. Comparable distributable cash flow is defined as comparable funds generated from operations less preferred share dividends, distributions to non-controlling interests and 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 - third quarter 2017

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

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $, except per share amounts)	**2017**	**2016**	**2017**	**2016**
Canadian Natural Gas Pipelines	**316**	329	**903**	943
U.S. Natural Gas Pipelines	**337**	332	**1,299**	787
Mexico Natural Gas Pipelines	**95**	98	**333**	184
Liquids Pipelines	**203**	183	**681**	593
Energy	**237**	(828)	**1,080**	(583)
Corporate	**(29)**	(36)	**(102)**	(87)
Total segmented earnings	**1,159**	78	**4,194**	1,837
Interest expense	**(504)**	(522)	**(1,528)**	(1,456)
Allowance for funds used during construction	**145**	110	**367**	322
Interest income and other	**84**	12	**193**	118
Income/(loss) before income taxes	**884**	(322)	**3,226**	821
Income tax (expense)/recovery	**(188)**	266	**(781)**	(78)
Net income/(loss)	**696**	(56)	**2,445**	743
Net income attributable to non-controlling interests	**(44)**	(52)	**(189)**	(184)
Net income/(loss) attributable to controlling interests	**652**	(108)	**2,256**	559
Preferred share dividends	**(40)**	(27)	**(120)**	(77)
Net income/(loss) attributable to common shares	**612**	(135)	**2,136**	482
Net income/(loss) per common share - basic	**$0.70**	($0.17)	**$2.46**	$0.66
- diluted	**$0.70**	($0.17)	**$2.45**	$0.66

Net income attributable to common shares increased by $747 million and $1,654 million or $0.87 and $1.80 per share for the three and nine months ended September 30, 2017 compared to the same periods in 2016. Net income per common share in 2017 included the dilutive effect of issuing 161 million common shares in 2016, of which 60 million were issued in fourth quarter 2016.

The 2017 results included:

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

The 2016 results included:

- a $656 million after-tax impairment on Ravenswood goodwill. As a result of information received during the process to monetize our U.S. Northeast Power business in third quarter 2016, it was determined that the fair value of Ravenswood no longer exceeded its carrying value
- a $176 million after-tax impairment charge in first quarter on the carrying value of our Alberta PPAs as a result of our decision to terminate the PPAs
- costs associated with the acquisition of Columbia including an after-tax charge of $67 million in third quarter, primarily relating to retention, severance and integration expenses, and $206 million year-to-date which also included $109 million related to the dividend equivalent payments on the subscription receipts issued as part of the permanent financing of the transaction, $36 million related to acquisition costs and $6 million related to interest earned on the subscription receipt funds held in escrow
- $28 million of income tax recoveries in third quarter related to the realized loss on a third party sale of Keystone XL project assets. A provision for the expected loss on these assets was included in our fourth quarter 2015 impairment charge, but the related income tax recoveries could not be recorded until realized
- an after-tax charge of $9 million in third quarter and $24 million year-to-date related to Keystone XL costs for the maintenance and liquidation of project assets which are expensed pending further advancement of the project
- an after-tax charge of $10 million year-to-date for restructuring charges mainly related to expected future losses under lease commitments. These charges formed part of a restructuring initiative, which commenced in 2015, to maximize the effectiveness and efficiency of our existing operations and reduce overall costs
- $3 million of after-tax costs related to the monetization of our U.S. Northeast Power business
- an additional $3 million after-tax loss on the sale of TC Offshore which closed on March 31, 2016.

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

Comparable earnings decreased by $8 million and increased by $489 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016 as discussed below in the reconciliation of net income to comparable earnings.

RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS

(unaudited - millions of $, except per share amounts)	three months ended September 30 2017	three months ended September 30 2016	nine months ended September 30 2017	nine months ended September 30 2016
Net income/(loss) attributable to common shares	**612**	(135)	**2,136**	482
Specific items (net of tax):				
Net loss/(gain) on sales of U.S. Northeast power assets	**12**	3	**(243)**	3
Integration and acquisition related costs – Columbia	**30**	67	**69**	206
Keystone XL asset costs	**8**	9	**19**	24
Keystone XL income tax recoveries	**—**	(28)	**(7)**	(28)
Ravenswood goodwill impairment	**—**	656	**—**	656
Alberta PPA terminations	**—**	—	**—**	176
Restructuring costs	**—**	—	**—**	10
TC Offshore loss on sale	**—**	—	**—**	3
Risk management activities[1]	**(48)**	50	**(3)**	(50)
Comparable earnings	**614**	622	**1,971**	1,482
Net income/(loss) per common share	**$0.70**	($0.17)	**$2.46**	$0.66
Specific items (net of tax):				
Net loss/(gain) on sales of U.S. Northeast power assets	**0.01**	—	**(0.28)**	—
Integration and acquisition related costs – Columbia	**0.03**	0.09	**0.08**	0.29
Keystone XL asset costs	**0.01**	0.01	**0.02**	0.03
Keystone XL income tax recoveries	**—**	(0.03)	**(0.01)**	(0.04)
Ravenswood goodwill impairment	**—**	0.82	**—**	0.89
Alberta PPA terminations	**—**	—	**—**	0.25
Restructuring costs	**—**	—	**—**	0.01
Risk management activities	**(0.05)**	0.06	**—**	(0.07)
Comparable earnings per common share	**$0.70**	$0.78	**$2.27**	$2.02

1

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

Comparable earnings decreased by $8 million or $0.08 per share for the three months ended September 30, 2017 compared to the same period in 2016. This decrease was primarily the net effect of:

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

Comparable earnings per share for the three months ended September 30, 2017 also included the dilutive effect of issuing 60 million common shares in fourth quarter 2016.

Comparable earnings increased by $489 million or $0.25 per share for the nine months ended September 30, 2017 compared to the same period in 2016. This increase was primarily the net effect of:

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

Comparable earnings per share for the nine months ended September 30, 2017 included the dilutive effect of issuing 161 million common shares in 2016.

Capital Program

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

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

Near-term projects

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

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

2 Our proportionate share.

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

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

Medium to longer-term projects

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

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

1 Our proportionate share.
2 Carrying value reflects amount remaining after impairment charge recorded in fourth quarter 2015.
3 Reflects U.S./Canada foreign exchange rate of 1.25 at September 30, 2017.

Outlook

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

Consolidated capital spending

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

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

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

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

Net income and comparable EBITDA for our rate-regulated Canadian Natural Gas Pipelines are generally affected by our approved ROE, our investment base, our level of deemed common equity and incentive earnings or losses. Changes in depreciation, financial charges and income taxes also impact comparable EBITDA but do not have a significant impact on net income as they are almost entirely recovered in revenues on a flow-through basis.

NET INCOME - NGTL SYSTEM AND CANADIAN MAINLINE

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

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

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

DEPRECIATION AND AMORTIZATION

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

OPERATING STATISTICS - NGTL SYSTEM AND CANADIAN MAINLINE

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

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

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 nine months ended September 30, 2017 were 716 Bcf (2016 – 802 Bcf). Average per day was 2.6 Bcf (2016 – 2.9 Bcf).

U.S. Natural Gas Pipelines

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEPRECIATION AND AMORTIZATION

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

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

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

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

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

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

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

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

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

DEPRECIATION AND AMORTIZATION

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

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

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

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

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

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

DEPRECIATION AND AMORTIZATION

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

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

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 TC Hydro earnings included up to April 19, 2017 sale date; Ravenswood, Ironwood, Ocean State Power and Kibby Wind earnings included up to June 2, 2017 sale date.
4 Depreciation of U.S. Northeast power assets ceased effective November 2016 when classified as held for sale.

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

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

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

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

1 Includes the realized gains and losses from financial derivatives used to manage Canadian Power's assets which are presented on a net basis in Western and Eastern Power revenues. The unrealized gains and losses from financial derivatives have been excluded to arrive at comparable EBITDA.
2 Includes revenues from the sale of unused natural gas transportation and sale of excess natural gas purchased for generation.
3 Included Alberta PPAs up to March 7, 2016 when the PPAs were terminated.
4 The percentage of time the plant was available to generate power, regardless of whether it was running.

Western Power

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

Eastern Power

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

DEPRECIATION AND AMORTIZATION

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

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

1 Represents our 48.4 per cent (2016 - 48.5 per cent) ownership interest in Bruce Power. Sales volumes include deemed generation.
2 The percentage of time the plant was available to generate power, regardless of whether it was running.
3 Calculation based on actual and deemed generation. Realized sales prices per MWh includes realized gains and losses from contracting activities and cost flow-through items. Excludes unrealized gains and losses on contracting activities and non-electricity revenues.

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

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

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

U.S. POWER

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

NATURAL GAS STORAGE AND OTHER

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

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

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

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

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

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

OTHER INCOME STATEMENT ITEMS

Interest expense

(unaudited - millions of $)	three months ended September 30		nine months ended September 30	
	2017	**2016**	**2017**	**2016**
Interest on long-term debt and junior subordinated notes				
Canadian dollar-denominated	**(130)**	(122)	**(356)**	(343)
U.S. dollar-denominated	**(314)**	(315)	**(954)**	(811)
Foreign exchange impact	**(79)**	(102)	**(293)**	(260)
	(523)	(539)	**(1,603)**	(1,414)
Other interest and amortization expense	**(29)**	(23)	**(74)**	(60)
Capitalized interest	**49**	46	**150**	133
Interest expense included in comparable earnings	**(503)**	(516)	**(1,527)**	(1,341)
Specific items:				
Integration and acquisition related costs – Columbia	**—**	(6)	**—**	(115)
Risk management activities	**(1)**	—	**(1)**	—
Interest expense	**(504)**	(522)	**(1,528)**	(1,456)

Interest expense decreased by $18 million in the three months ended September 30, 2017 compared to the same period in 2016 and primarily reflects the net effect of:

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

Interest expense increased by $72 million for the nine months ended September 30, 2017 compared to the same period in 2016 and primarily reflects the net effect of:

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

Allowance for funds used during construction

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

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

Interest income and other

(unaudited - millions of $)	three months ended September 30		nine months ended September 30	
	2017	**2016**	**2017**	**2016**
Interest income and other included in comparable earnings	**58**	12	**103**	63
Specific items:				
Integration and acquisition related costs – Columbia	**—**	—	**—**	6
Foreign exchange (loss)/gain – inter-affiliate loan	**(7)**	—	**1**	—
Risk management activities	**33**	—	**89**	49
Interest income and other	**84**	12	**193**	118

Interest income and other increased by $72 million for the three months ended September 30, 2017 compared to the same period in 2016 and was primarily the net effect of:

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

Interest income and other increased by $75 million for the nine months ended September 30, 2017 compared to the same period in 2016 and was primarily the net effect of:

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

Income tax expense

(unaudited - millions of $)	three months ended September 30		nine months ended September 30	
	2017	**2016**	**2017**	**2016**
Income tax expense included in comparable earnings	**(163)**	(261)	**(605)**	(630)
Specific items:				
Ravenswood goodwill impairment	**—**	429	**—**	429
Sales of U.S. Northeast power assets	**—**	2	**(226)**	2
Integration and acquisition related costs – Columbia	**2**	32	**22**	32
Keystone XL asset costs	**2**	5	**4**	13
Keystone XL income tax recoveries	**—**	28	**7**	28
Alberta PPA terminations	**—**	—	**—**	64
Restructuring costs	**—**	—	**—**	4
TC Offshore loss on sale	**—**	—	**—**	1
Risk management activities	**(29)**	31	**17**	(21)
Income tax (expense)/recovery	**(188)**	266	**(781)**	(78)

Income tax expense included in comparable earnings decreased by $98 million for the three months ended September 30, 2017 compared to the same periods in 2016 mainly as a result of lower comparable pre-tax earnings in 2017 compared to 2016 and changes in the proportion of income earned between Canadian and foreign jurisdictions.

Income tax expense included in comparable earnings decreased by $25 million for the nine months ended September 30, 2017 compared to the same period in 2016 mainly as a result of changes in the proportion of income earned between Canadian and foreign jurisdictions and lower flow-through taxes in 2017 on Canadian rate-regulated pipelines, partially offset by higher pre-tax earnings in 2017 compared to 2016.

Net income attributable to non-controlling interests

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

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

Preferred share dividends

(unaudited - millions of $)	three months ended September 30		nine months ended September 30	
	2017	**2016**	**2017**	**2016**
Preferred share dividends	**(40)**	(27)	**(120)**	(77)

Preferred share dividends increased by $13 million and $43 million for the three and nine months ended September 30, 2017 compared to the same periods in 2016 primarily due to the issuance of Series 13 and Series 15 preferred shares in April 2016 and November 2016, respectively.

Recent developments

CANADIAN NATURAL GAS PIPELINES

NGTL System

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

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

Towerbirch Expansion

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

North Montney

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

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

NGTL 2018 Revenue Requirement

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

Canadian Mainline

Dawn Long-Term Fixed Price Service (LTFP)

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

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

Canadian Mainline 2018 - 2020 Toll Review

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

Maple Compressor Expansion Project

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

Coastal GasLink

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

Prince Rupert Gas Transmission

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

U.S. NATURAL GAS PIPELINES

Leach XPress Project

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

Rayne XPress Project

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

Mountaineer XPress Project

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

Midstream - Gibraltar Pipeline Project

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

Buckeye XPress Project

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

Portland XPress Project

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

FERC Update

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

Great Lakes

Rate Case

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

Impact of Dawn LTFP

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

Northern Border Settlement

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

Sale of Iroquois and PNGTS to TC PipeLines, LP

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

Columbia Pipeline Partners LP

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

MEXICO NATURAL GAS PIPELINES

TransGas

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

LIQUIDS PIPELINES

Energy East and Related Projects

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

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

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

Keystone XL

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

Given the passage of time since the Keystone XL Presidential Permit application was previously denied in November 2015, we are updating the shipping contracts and anticipate the core contract shipper group will be modified with the introduction of new shippers and reductions in volume commitments by other shippers. We anticipate commercial support for the project to be substantially similar to that which existed when we first applied for a Keystone XL pipeline permit.

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

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

Grand Rapids

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

Northern Courier

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

ENERGY

U.S. Power

Monetization of U.S. Northeast power business

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

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

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

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

Ontario Solar

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

Financial condition

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

We believe we have the financial capacity to fund our existing capital program through our predictable and growing cash flow from operations, access to capital markets (including through our At-The-Market (ATM) equity issuance program), our Dividend Reinvestment Plan (DRP), portfolio management including proceeds from potential drop downs of additional natural gas pipeline assets to TC PipeLines, LP, cash on hand and substantial committed credit facilities.

At September 30, 2017, our current assets were $5.8 billion and current liabilities were $11.4 billion, leaving us with a working capital deficit of $5.6 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 credit facilities.

CASH PROVIDED BY OPERATING ACTIVITIES

(unaudited - millions of $, except per share amounts)	three months ended September 30		nine months ended September 30	
	2017	**2016**	**2017**	**2016**
Net cash provided by operations	**1,185**	1,265	**3,840**	3,494
Increase/(decrease) in operating working capital	**86**	58	**224**	(28)
Funds generated from operations[1]	**1,271**	1,323	**4,064**	3,466
Specific items:				
Integration and acquisition related costs – Columbia	**32**	99	**84**	238
Keystone XL asset costs	**10**	14	**23**	37
U.S. Northeast power disposition costs	**3**	5	**20**	5
Comparable funds generated from operations[1]	**1,316**	1,441	**4,191**	3,746
Dividends on preferred shares	**(39)**	(28)	**(116)**	(74)
Distributions paid to non-controlling interests	**(66)**	(77)	**(215)**	(201)
Maintenance capital expenditures including equity investments	**(442)**	(342)	**(988)**	(858)
Comparable distributable cash flow[1]	**769**	994	**2,872**	2,613
Comparable distributable cash flow per common share[1]	**$0.88**	$1.25	**$3.30**	$3.56

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

COMPARABLE FUNDS GENERATED FROM OPERATIONS

Comparable funds generated from operations, a non-GAAP measure, decreased $125 million for the three months ended September 30, 2017 compared to the same period in 2016 primarily due to lower comparable EBITDA (excluding income from equity investments) and increased funding of our U.S. employee post-retirement benefit plans, partially offset by higher distributions from our equity investments and interest income and other.

Comparable funds generated from operations increased $445 million for the nine months ended September 30, 2017 compared to the same period in 2016 primarily due to higher comparable EBITDA (excluding income from equity investments) and higher distributions from our equity investments, partially offset by higher interest expense and increased funding of our employee post-retirement benefit plans.

COMPARABLE DISTRIBUTABLE CASH FLOW

Comparable distributable cash flow, a non-GAAP measure, helps us assess the cash available to common shareholders before capital allocation. The decrease for the three months ended September 30, 2017 compared to the same period in 2016 was primarily driven by the decrease in comparable funds generated from operations and higher maintenance capital expenditures. The increase on a year-to-date basis is primarily due to the increase in comparable funds generated from operations, partially offset by higher maintenance capital expenditures. Comparable distributable cash flow per common share for the three and nine months ended September 30, 2017 also includes the dilutive effect of issuing 161 million common shares in 2016, of which 60 million were issued in fourth quarter 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 September 30		**nine months ended September 30**	
(unaudited - millions of $)	**2017**	**2016**	**2017**	**2016**
Canadian Natural Gas Pipelines	**181**	96	**300**	190
U.S. Natural Gas Pipelines	**217**	189	**512**	404
Other	**44**	57	**176**	264
Maintenance capital expenditures including equity investments	**442**	342	**988**	858

CASH USED IN INVESTING ACTIVITIES

	three months ended September 30		**nine months ended September 30**	
(unaudited - millions of $)	**2017**	**2016**	**2017**	**2016**
Capital spending				
Capital expenditures	**(2,031)**	(1,444)	**(5,383)**	(3,262)
Capital projects in development	**(37)**	(62)	**(135)**	(219)
Contributions to equity investments	**(475)**	(286)	**(1,140)**	(570)
	(2,543)	(1,792)	**(6,658)**	(4,051)
Restricted cash	**—**	13,113	**—**	—
Acquisitions, net of cash acquired	**—**	(12,609)	**—**	(13,608)
Proceeds from sales of assets, net of transaction costs	**—**	—	**4,147**	6
Other distributions from equity investments	**—**	—	**362**	725
Deferred amounts and other	**165**	(14)	**(87)**	18
Net cash used in investing activities	**(2,378)**	(1,302)	**(2,236)**	(16,910)

Capital expenditures in 2017 were primarily related to:

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

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

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

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

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

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

CASH PROVIDED BY/(USED IN) FINANCING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2017**	**2016**	**2017**	**2016**
Notes payable issued/(repaid), net	**451**	(423)	**1,232**	(100)
Long-term debt issued, net of issue costs	**1,151**	6	**1,968**	12,333
Long-term debt repaid	**(46)**	(53)	**(5,515)**	(2,343)
Junior subordinated notes issued, net of issue costs	**(3)**	1,551	**3,468**	1,551
Dividends and distributions paid	**(459)**	(502)	**(1,313)**	(1,434)
Common shares issued, net of issue costs	**6**	(37)	**42**	4,337
Common shares repurchased	**—**	—	**—**	(14)
Preferred shares issued, net of issue costs	**—**	—	**—**	492
Partnership units of TC PipeLines, LP issued, net of issue costs	**43**	45	**162**	151
Common units of Columbia Pipeline Partners LP acquired	**—**	—	**(1,205)**	—
Net cash provided by/(used in) financing activities	**1,143**	587	**(1,161)**	14,973

LONG-TERM DEBT ISSUED

The following table outlines significant debt issuances:

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

LONG-TERM DEBT REPAID

The following table outlines significant debt repaid:

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

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

JUNIOR SUBORDINATED NOTES ISSUED

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

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

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

In May 2017, the Trust issued $1.5 billion of Trust Notes - Series 2017-B (Trust Notes) to third party investors with a fixed interest rate of 4.65 per cent for the first ten years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for $1.5 billion of junior subordinated notes of TCPL at an initial fixed rate of 4.90 per cent, including a 0.25 per cent administration charge. The rate will reset commencing May 2027 until May 2047 to the then three month Bankers' Acceptance rate plus 3.33 per cent per annum; from May 2047 until May 2077, the interest rate will reset to the then three month Bankers' Acceptance rate plus 4.08 per cent per annum.

The junior subordinated notes are callable at TCPL's option at any time on or after May 18, 2027 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

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

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

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 to market prices over a specified period. For the dividends declared on July 28, 2017, approximately 35 per cent of common share dividends declared were designated to be reinvested by shareholders in TransCanada common shares under the DRP. Year-to-date in 2017, the participation rate amongst common shareholders has been approximately 36 per cent, resulting in $594 million of common equity issued.

TRANSCANADA CORPORATION ATM EQUITY ISSUANCE PROGRAM

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

TC PIPELINES, LP ATM EQUITY ISSUANCE PROGRAM

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

DIVIDENDS

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

Quarterly dividend on our common shares
$0.625 per share
Payable on January 31, 2018 to shareholders of record at the close of business on December 29, 2017

Quarterly dividends on our preferred shares	
Series 1	$0.204125
Series 2	$0.16774247
Series 3	$0.1345
Series 4	$0.12741370
Payable on December 29, 2017 to shareholders of record at the close of business on November 30, 2017	
Series 5	$0.14143750
Series 6	$0.16062192
Series 7	$0.25
Series 9	$0.265625
Payable on January 30, 2018 to shareholders of record at the close of business on January 2, 2018	
Series 11	$0.2375
Series 13	$0.34375
Series 15	$0.30625
Payable on November 30, 2017 to shareholders of record at the close of business on November 21, 2017	

SHARE INFORMATION

as at November 3, 2017		
Common shares	**Issued and outstanding**	
	878 million	
Preferred shares	**Issued and outstanding**	**Convertible to**
Series 1	9.5 million	Series 2 preferred shares
Series 2	12.5 million	Series 1 preferred shares
Series 3	8.5 million	Series 4 preferred shares
Series 4	5.5 million	Series 3 preferred shares
Series 5	12.7 million	Series 6 preferred shares
Series 6	1.3 million	Series 5 preferred shares
Series 7	24 million	Series 8 preferred shares
Series 9	18 million	Series 10 preferred shares
Series 11	10 million	Series 12 preferred shares
Series 13	20 million	Series 14 preferred shares
Series 15	40 million	Series 16 preferred shares
Options to buy common shares	**Outstanding**	**Exercisable**
	11 million	7 million

CREDIT FACILITIES

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

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

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

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

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

CONTRACTUAL OBLIGATIONS

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

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

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

Financial risks and financial instruments

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

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

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

LIQUIDITY RISK

We manage our liquidity risk by continuously forecasting our cash flow for a 12 month period to ensure we have adequate cash balances, cash flow from operations, committed and demand credit facilities and access to capital markets to meet our operating, financing and capital expenditure obligations under both normal and stressed economic conditions.

COUNTERPARTY CREDIT RISK

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

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

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

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

LOAN RECEIVABLE FROM AFFILIATE

We hold a 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline. We account for the joint venture as an equity investment. On April 21, 2017, we entered into a MXN$13.6 billion unsecured revolving credit facility with the joint venture, which bears interest at a floating rate and matures in March 2022.

FOREIGN EXCHANGE AND INTEREST RATE RISK

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

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

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

Average exchange rate - U.S. to Canadian dollars

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

three months ended September 30, 2017	**1.25**
three months ended September 30, 2016	1.31

nine months ended September 30, 2017	**1.31**
nine months ended September 30, 2016	1.32

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

Significant U.S. dollar-denominated amounts

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

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:

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

1 Fair values equal carrying values.

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

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

(unaudited - millions of Canadian $, unless noted otherwise)	September 30, 2017	December 31, 2016
Notional amount	**24,900 (US 19,900)**	26,600 (US 19,800)
Fair value	**28,300 (US 22,600)**	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 $)	September 30, 2017	December 31, 2016
Other current assets	**286**	376
Intangible and other assets	**89**	133
Accounts payable and other	**(453)**	(607)
Other long-term liabilities	**(155)**	(330)
	(233)	(428)

Unrealized and realized gains/(losses) of derivative instruments

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

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

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

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

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

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

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

Other information

CONTROLS AND PROCEDURES

Management, including our President and CEO and our CFO, evaluated the effectiveness of our disclosure controls and procedures as at September 30, 2017, as required by the Canadian securities regulatory authorities and by the SEC, and concluded that our disclosure controls and procedures are effective at a reasonable assurance level.

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

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

There were no changes in third quarter 2017 that had or are likely to have a material impact on our internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES AND ACCOUNTING POLICY CHANGES

When we prepare financial statements that conform with U.S. GAAP, we are required to make estimates and assumptions that affect the timing and amounts we record for our assets, liabilities, revenues and expenses because these items may be affected by future events. We base the estimates and assumptions on the most current information available, using our best judgement. We also regularly assess the assets and liabilities themselves. A summary of our critical accounting estimates is included in our 2016 Annual Report.

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

Changes in accounting policies for 2017

Inventory

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

Derivatives and hedging

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

Equity method investments

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

Employee share-based payments

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

Consolidation

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

Future accounting changes

Revenue from contracts with customers

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

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

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

Financial instruments

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

Leases

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

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

Measurement of credit losses on financial instruments

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

Income taxes

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

Restricted cash

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

Goodwill impairment

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

Employee post-retirement benefits

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

Amortization on purchased callable debt securities

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

Hedge accounting

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

Reconciliation of non-GAAP measures

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

1

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

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

(unaudited - millions of $, except per share amounts)	2017			2016				2015
	Third	**Second**	**First**	**Fourth**	**Third**	**Second**	**First**	**Fourth**
Revenues	**3,242**	3,217	3,391	3,619	3,632	2,751	2,503	2,851
Net income/(loss) attributable to common shares	**612**	881	643	(358)	(135)	365	252	(2,458)
Comparable earnings	**614**	659	698	626	622	366	494	453
Per share statistics								
Net income/(loss) per common share - basic and diluted	**$0.70**	$1.01	$0.74	($0.43)	($0.17)	$0.52	$0.36	($3.47)
Comparable earnings per common share	**$0.70**	$0.76	$0.81	$0.75	$0.78	$0.52	$0.70	$0.64
Dividends declared per common share	**$0.625**	$0.625	$0.625	$0.565	$0.565	$0.565	$0.565	$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 generally based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income are also affected by:

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

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

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

FACTORS AFFECTING FINANCIAL INFORMATION BY QUARTER

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

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

In third quarter 2017, comparable earnings excluded:

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

In second quarter 2017, comparable earnings excluded:

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

In first quarter 2017, comparable earnings excluded:

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

In fourth quarter 2016, comparable earnings excluded:

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

In third quarter 2016, comparable earnings excluded:

- a $656 million after-tax impairment on Ravenswood goodwill. As a result of information received during the process to monetize our U.S. Northeast Power business in third quarter 2016, it was determined that the fair value of Ravenswood no longer exceeded its carrying value
- costs associated with the acquisition of Columbia including a charge of $67 million after tax primarily related to retention, severance and integration expenses
- $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 which closed in early 2016
- a net charge of $60 million after tax for our business restructuring and transformation initiative comprised of $28 million mainly related to 2015 severance costs and a provision of $32 million for 2016 planned severance costs and expected future losses under lease commitments. These charges formed part of a restructuring initiative which commenced in 2015 to maximize the effectiveness and efficiency of our existing operations and reduce overall costs
- a $43 million after-tax charge related to an impairment in value of turbine equipment held for future use in our Energy business
- a charge of $27 million after tax related to Bruce Power's retirement of debt in conjunction with the merger of the Bruce A and Bruce B partnerships
- a $199 million positive income adjustment related to the impact on our net income from non-controlling interests of TC PipeLines, LP's impairment of their equity investment in Great Lakes.

Condensed consolidated statement of income

(unaudited - millions of Canadian $, except per share amounts)	three months ended September 30		nine months ended September 30	
	2017	**2016**	**2017**	**2016**
Revenues				
Canadian Natural Gas Pipelines	**921**	951	**2,725**	2,677
U.S. Natural Gas Pipelines	**811**	812	**2,684**	1,585
Mexico Natural Gas Pipelines	**139**	121	**432**	249
Liquids Pipelines	**437**	440	**1,410**	1,292
Energy	**934**	1,308	**2,599**	3,083
	3,242	3,632	**9,850**	8,886
Income from Equity Investments	**156**	154	**527**	355
Operating and Other Expenses				
Plant operating costs and other	**976**	1,177	**2,980**	2,646
Commodity purchases resold	**621**	783	**1,711**	1,628
Property taxes	**127**	136	**442**	405
Depreciation and amortization	**506**	527	**1,539**	1,425
Goodwill and other asset impairment charges	**—**	1,085	**—**	1,296
	2,230	3,708	**6,672**	7,400
(Loss)/Gain on Sale of Assets	**(9)**	—	**489**	(4)
Financial Charges				
Interest expense	**504**	522	**1,528**	1,456
Allowance for funds used during construction	**(145)**	(110)	**(367)**	(322)
Interest income and other	**(84)**	(12)	**(193)**	(118)
	275	400	**968**	1,016
Income/(Loss) before Income Taxes	**884**	(322)	**3,226**	821
Income Tax Expense/(Recovery)				
Current	**6**	14	**128**	103
Deferred	**182**	(280)	**653**	(25)
	188	(266)	**781**	78
Net Income/(Loss)	**696**	(56)	**2,445**	743
Net income attributable to non-controlling interests	**44**	52	**189**	184
Net Income/(Loss)Attributable to Controlling Interests	**652**	(108)	**2,256**	559
Preferred share dividends	**40**	27	**120**	77
Net Income/(Loss) Attributable to Common Shares	**612**	(135)	**2,136**	482
Net Income/(Loss) per Common Share				
Basic	**$0.70**	($0.17)	**$2.46**	$0.66
Diluted	**$0.70**	($0.17)	**$2.45**	$0.66
Dividends Declared per Common Share	**$0.625**	$0.565	**$1.875**	$1.695
Weighted Average Number of Common Shares (millions)				
Basic	**873**	797	**870**	734
Diluted	**875**	798	**872**	735

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

(unaudited - millions of Canadian $)	three months ended September 30 2017	three months ended September 30 2016	nine months ended September 30 2017	nine months ended September 30 2016
Net Income/(Loss)	**696**	(56)	**2,445**	743
Other Comprehensive (Loss)/Income, Net of Income Taxes				
Foreign currency translation (losses)/gains on net investment in foreign operations	**(370)**	55	**(721)**	(152)
Reclassification of foreign currency translation gains on net investment in foreign operations	**—**	—	**(77)**	—
Change in fair value of net investment hedges	**(1)**	(1)	**(3)**	(9)
Change in fair value of cash flow hedges	**1**	5	**4**	21
Reclassification to net income of gains and losses on cash flow hedges	**—**	—	**(1)**	40
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**2**	—	**2**	—
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**4**	4	**11**	12
Other comprehensive income on equity investments	**3**	4	**6**	11
Other comprehensive (loss)/income (Note 9)	**(361)**	67	**(779)**	(77)
Comprehensive Income	**335**	11	**1,666**	666
Comprehensive (loss)/income attributable to non-controlling interests	**(25)**	76	**31**	104
Comprehensive Income/(Loss) Attributable to Controlling Interests	**360**	(65)	**1,635**	562
Preferred share dividends	**40**	27	**120**	77
Comprehensive Income/(Loss) Attributable to Common Shares	**320**	(92)	**1,515**	485

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of cash flows

	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian $)	2017	2016	2017	2016
Cash Generated from Operations				
Net income/(loss)	**696**	(56)	**2,445**	743
Depreciation and amortization	**506**	527	**1,539**	1,425
Goodwill and other asset impairment charges	**—**	1,085	**—**	1,296
Deferred income taxes	**182**	(280)	**653**	(25)
Income from equity investments	**(156)**	(154)	**(527)**	(355)
Distributions received from operating activities of equity investments	**296**	185	**743**	625
Employee post-retirement benefits funding, net of expense	**(73)**	4	**(64)**	(5)
Loss/(gain) on sale of assets	**9**	—	**(489)**	4
Equity allowance for funds used during construction	**(107)**	(71)	**(249)**	(195)
Unrealized (gains)/losses on financial instruments	**(77)**	82	**14**	(71)
Other	**(5)**	1	**(1)**	24
(Increase)/decrease in operating working capital	**(86)**	(58)	**(224)**	28
Net cash provided by operations	**1,185**	1,265	**3,840**	3,494
Investing Activities				
Capital expenditures	**(2,031)**	(1,444)	**(5,383)**	(3,262)
Capital projects in development	**(37)**	(62)	**(135)**	(219)
Contributions to equity investments	**(475)**	(286)	**(1,140)**	(570)
Restricted cash	**—**	13,113	**—**	—
Acquisitions, net of cash acquired	**—**	(12,609)	**—**	(13,608)
Proceeds from sales of assets, net of transaction costs	**—**	—	**4,147**	6
Other distributions from equity investments	**—**	—	**362**	725
Deferred amounts and other	**165**	(14)	**(87)**	18
Net cash used in investing activities	**(2,378)**	(1,302)	**(2,236)**	(16,910)
Financing Activities				
Notes payable issued/(repaid), net	**451**	(423)	**1,232**	(100)
Long-term debt issued, net of issue costs	**1,151**	6	**1,968**	12,333
Long-term debt repaid	**(46)**	(53)	**(5,515)**	(2,343)
Junior subordinated notes issued, net of issue costs	**(3)**	1,551	**3,468**	1,551
Dividends on common shares	**(354)**	(397)	**(982)**	(1,159)
Dividends on preferred shares	**(39)**	(28)	**(116)**	(74)
Distributions paid to non-controlling interests	**(66)**	(77)	**(215)**	(201)
Common shares issued, net of issue costs	**6**	(37)	**42**	4,337
Common shares repurchased	**—**	—	**—**	(14)
Preferred shares issued, net of issue costs	**—**	—	**—**	492
Partnership units of TC PipeLines, LP issued, net of issue costs	**43**	45	**162**	151
Common units of Columbia Pipeline Partners LP acquired	**—**	—	**(1,205)**	—
Net cash provided by/(used in) financing activities	**1,143**	587	**(1,161)**	14,973
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(16)**	3	**(35)**	(127)
(Decrease)/Increase in Cash and Cash Equivalents	**(66)**	553	**408**	1,430
Cash and Cash Equivalents				
Beginning of period	**1,490**	1,727	**1,016**	850
Cash and Cash Equivalents				
End of period	**1,424**	2,280	**1,424**	2,280

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		September 30, 2017	December 31, 2016
ASSETS			
Current Assets			
Cash and cash equivalents		**1,424**	1,016
Accounts receivable		**2,820**	2,075
Inventories		**390**	368
Assets held for sale		**431**	3,717
Other		**743**	908
		5,808	8,084
Plant, Property and Equipment	net of accumulated depreciation of $23,257 and $22,263, respectively	**55,842**	54,475
Equity Investments		**6,349**	6,544
Regulatory Assets		**1,309**	1,322
Goodwill		**13,076**	13,958
Intangible and Other Assets		**3,215**	3,026
Restricted Investments		**810**	642
		86,409	88,051
LIABILITIES			
Current Liabilities			
Notes payable		**1,963**	774
Accounts payable and other		**4,084**	3,861
Dividends payable		**559**	526
Accrued interest		**541**	595
Liabilities related to assets held for sale		**18**	86
Current portion of long-term debt		**4,216**	1,838
		11,381	7,680
Regulatory Liabilities		**2,512**	2,121
Other Long-Term Liabilities		**745**	1,183
Deferred Income Tax Liabilities		**8,069**	7,662
Long-Term Debt		**30,414**	38,312
Junior Subordinated Notes		**7,004**	3,931
		60,125	60,889
Common Units Subject to Rescission or Redemption		**—**	1,179
EQUITY			
Common shares, no par value		**20,744**	20,099
Issued and outstanding:	September 30, 2017 - 874 million shares		
	December 31, 2016 - 864 million shares		
Preferred shares		**3,980**	3,980
Additional paid-in capital		**—**	—
Retained earnings		**1,324**	1,138
Accumulated other comprehensive loss		**(1,581)**	(960)
Controlling Interests		**24,467**	24,257
Non-controlling interests		**1,817**	1,726
		26,284	25,983
		86,409	88,051

Commitments, Contingencies and Guarantees (Note 13)
Variable Interest Entities (Note 14)
Subsequent Event (Note 15)

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of equity

	nine months ended September 30	
(unaudited - millions of Canadian $)	**2017**	**2016**
Common Shares		
Balance at beginning of period	**20,099**	12,102
Shares issued on exercise of stock options	**46**	70
Shares repurchased	**—**	(6)
Shares issued under dividend reinvestment and share purchase plan	**599**	—
Shares issued on exchange of subscription receipts	**—**	4,314
Balance at end of period	**20,744**	16,480
Preferred Shares		
Balance at beginning of period	**3,980**	2,499
Shares issued under public offering, net of issue costs	**—**	493
Balance at end of period	**3,980**	2,992
Additional Paid-In Capital		
Balance at beginning of period	**—**	7
Issuance of stock options, net of exercises	**4**	3
Dilution impact from TC PipeLines, LP units issued	**18**	17
Impact of common shares repurchased	**—**	(8)
Impact of asset drop downs to TC PipeLines, LP	**(202)**	(38)
Impact of Columbia Pipeline Partners LP acquisition	**(171)**	—
Reclassification of Additional Paid-In Capital deficit to Retained Earnings	**351**	19
Balance at end of period	**—**	—
Retained Earnings		
Balance at beginning of period	**1,138**	2,769
Net income attributable to controlling interests	**2,256**	559
Common share dividends	**(1,633)**	(1,246)
Preferred share dividends	**(98)**	(71)
Adjustment related to employee share-based payments (Note 2)	**12**	—
Reclassification of Additional Paid-In Capital deficit to Retained Earnings	**(351)**	(19)
Balance at end of period	**1,324**	1,992
Accumulated Other Comprehensive Loss		
Balance at beginning of period	**(960)**	(939)
Other comprehensive loss	**(621)**	3
Balance at end of period	**(1,581)**	(936)
Equity Attributable to Controlling Interests	**24,467**	20,528
Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	**1,726**	1,717
Acquisition of non-controlling interests in Columbia Pipelines Partners LP	—	1,051
Net income attributable to non-controlling interests	**189**	184
Other comprehensive loss attributable to non-controlling interests	**(158)**	(80)
Issuance of TC PipeLines, LP units		
Proceeds, net of issue costs	**162**	151
Decrease in TransCanada's ownership of TC PipeLines, LP	**(29)**	(28)
Reclassification from/(to) common units of TC PipeLines, LP subject to rescission	**106**	(106)
Distributions declared to non-controlling interests	**(212)**	(200)
Impact of Columbia Pipeline Partners LP acquisition	**33**	—
Balance at end of period	**1,817**	2,689
Total Equity	**26,284**	23,217

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 annual audited consolidated financial statements for the year ended December 31, 2016, except as described in Note 2, Accounting changes.

2. Accounting changes

CHANGES IN ACCOUNTING POLICIES FOR 2017

Inventory

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

Derivatives and hedging

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

Equity method investments

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

Employee share-based payments

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

Consolidation

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

FUTURE ACCOUNTING CHANGES

Revenue from contracts with customers

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

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

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

Financial instruments

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

Leases

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

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

Measurement of credit losses on financial instruments

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

Income taxes

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

Restricted cash

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

Goodwill impairment

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

Employee post-retirement benefits

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

Amortization on purchased callable debt securities

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

Hedge accounting

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

3. Segmented information

three months ended September 30, 2017 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**921**	**811**	**139**	**437**	**934**	**—**	**3,242**
Income/(loss) from equity investments	**4**	**53**	**(11)**	**4**	**99**	**7**	**156**
Plant operating costs and other	**(318)**	**(341)**	**(10)**	**(145)**	**(126)**	**(36)**	**(976)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(621)**	**—**	**(621)**
Property taxes	**(63)**	**(41)**	**—**	**(22)**	**(1)**	**—**	**(127)**
Depreciation and amortization	**(228)**	**(145)**	**(23)**	**(71)**	**(39)**	**—**	**(506)**
Loss on sale of assets	**—**	**—**	**—**	**—**	**(9)**	**—**	**(9)**
Segmented earnings/(loss)	**316**	**337**	**95**	**203**	**237**	**(29)**	**1,159**
Interest expense							**(504)**
Allowance for funds used during construction							**145**
Interest income and other							**84**
Income before income taxes							**884**
Income tax expense							**(188)**
Net income							**696**
Net income attributable to non-controlling interests							**(44)**
Net income attributable to controlling interests							**652**
Preferred share dividends							**(40)**
Net income attributable to common shares							**612**

three months ended September 30, 2016 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	951	812	121	440	1,308	—	3,632
Income/(loss) from equity investments	3	65	(2)	—	88	—	154
Plant operating costs and other	(340)	(369)	(8)	(163)	(261)	(36)	(1,177)
Commodity purchases resold	—	—	—	—	(783)	—	(783)
Property taxes	(65)	(38)	—	(21)	(12)	—	(136)
Depreciation and amortization	(220)	(138)	(13)	(73)	(83)	—	(527)
Asset impairment charges	—	—	—	—	(1,085)	—	(1,085)
Segmented earnings/(losses)	329	332	98	183	(828)	(36)	78
Interest expense							(522)
Allowance for funds used during construction							110
Interest income and other							12
Loss before income taxes							(322)
Income tax recovery							266
Net loss							(56)
Net income attributable to non-controlling interests							(52)
Net loss attributable to controlling interests							(108)
Preferred share dividends							(27)
Net loss attributable to common shares							(135)

nine months ended September 30, 2017 (unaudited - millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Revenues	**2,725**	**2,684**	**432**	**1,410**	**2,599**	**—**	**9,850**
Income/(loss) from equity investments	**9**	**175**	**—**	**3**	**341**	**(1)**	**527**
Plant operating costs and other	**(958)**	**(973)**	**(29)**	**(437)**	**(482)**	**(101)**	**(2,980)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(1,711)**	**—**	**(1,711)**
Property taxes	**(201)**	**(136)**	**—**	**(67)**	**(38)**	**—**	**(442)**
Depreciation and amortization	**(672)**	**(451)**	**(70)**	**(228)**	**(118)**	**—**	**(1,539)**
Gain on sale of assets	**—**	**—**	**—**	**—**	**489**	**—**	**489**
Segmented earnings/(loss)	**903**	**1,299**	**333**	**681**	**1,080**	**(102)**	**4,194**
Interest expense							**(1,528)**
Allowance for funds used during construction							**367**
Interest income and other							**193**
Income before income taxes							**3,226**
Income tax expense							**(781)**
Net income							**2,445**
Net income attributable to non-controlling interests							**(189)**
Net income attributable to controlling interests							**2,256**
Preferred share dividends							**(120)**
Net income attributable to common shares							**2,136**

nine months ended September 30, 2016 (unaudited - millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Revenues	2,677	1,585	249	1,292	3,083	—	8,886
Income/(loss) from equity investments	9	150	(2)	(1)	199	—	355
Plant operating costs and other	(886)	(597)	(34)	(417)	(625)	(87)	(2,646)
Commodity purchases resold	—	—	—	—	(1,628)	—	(1,628)
Property taxes	(202)	(78)	—	(67)	(58)	—	(405)
Depreciation and amortization	(655)	(269)	(29)	(214)	(258)	—	(1,425)
Asset impairment charges	—	—	—	—	(1,296)	—	(1,296)
Loss on sale of assets	—	(4)	—	—	—	—	(4)
Segmented earnings/(losses)	943	787	184	593	(583)	(87)	1,837
Interest expense							(1,456)
Allowance for funds used during construction							322
Interest income and other							118
Income before income taxes							821
Income tax expense							(78)
Net Income							743
Net income attributable to non-controlling interests							(184)
Net Income attributable to controlling interests							559
Preferred share dividends							(77)
Net Income attributable to common shares							482

TOTAL ASSETS

(unaudited - millions of Canadian $)	September 30, 2017	December 31, 2016
Canadian Natural Gas Pipelines	**17,010**	15,816
U.S. Natural Gas Pipelines	**34,897**	34,422
Mexico Natural Gas Pipelines	**5,470**	5,013
Liquids Pipelines	**16,436**	16,896
Energy	**8,979**	13,169
Corporate	**3,617**	2,735
	86,409	88,051

4. Assets held for sale

Solar Assets

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

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

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

5. Income taxes

The effective tax rates for the nine-month periods ended September 30, 2017 and 2016 were 24 per cent and 10 per cent, respectively. The higher effective tax rate in 2017 was primarily the result of changes in the proportion of income earned between Canadian and foreign jurisdictions and the goodwill impairment charge in 2016.

6. Long-term debt

LONG-TERM DEBT ISSUED

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

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

LONG-TERM DEBT RETIRED

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

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

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

In the three and nine months ended September 30, 2017, TransCanada capitalized interest related to capital projects of $49 million and $150 million (2016 - $46 million and $133 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					
	May 2017	Junior Subordinated Notes[1,2]	May 2077	1,500	4.90%
	March 2017	Junior Subordinated Notes[1,2]	March 2077	US 1,500	5.55%

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

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

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

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

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

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 between entities under common control, it was recognized in equity.

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

Common units of TC PipeLines, LP subject to rescission

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

9. Other comprehensive (loss)/income and accumulated other comprehensive loss

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

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

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

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

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

The changes in AOCI by component are as follows:

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

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 $68 million and losses of $1 million, respectively.

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

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

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 net of non-controlling interest losses of $158 million.

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

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

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

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

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

In third quarter 2017, the year to date lump sum payouts exceeded service and interest costs for the Columbia's DB plan. As a result, remeasurements were performed on the Columbia DB plan using a discount rate of 3.70 per cent. All other assumptions were consistent with those employed at December 31, 2016. The remeasurement of the Columbia DB plan increased the Company's unrealized actuarial gains by $16 million, of which $14 million was recorded in Regulatory assets and $2 million was recorded in Other comprehensive income.

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

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

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

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

LOAN RECEIVABLE FROM AFFILIATE

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

TransCanada holds a 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline. The Company accounts for the joint venture as an equity investment. On April 21, 2017, TransCanada entered into a MXN$13.6 billion unsecured revolving credit facility with the joint venture, which bears interest at a floating rate and matures in March 2022. At September 30, 2017, Intangible and other assets on the Company's condensed consolidated balance sheet included a $578 million loan receivable from the Sur de Texas joint venture. This loan receivable represents TransCanada's proportionate share of the debt financing requirements related to the joint venture and is included in Contributions to equity investments on the Company's condensed consolidated statement of cash flows. Interest income and other included income of $11 million and $14 million for the three and nine months ended September 30, 2017. These amounts were offset by a corresponding expense recorded in Income from equity investments.

NET INVESTMENT IN FOREIGN OPERATIONS

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

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

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

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

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

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

FINANCIAL INSTRUMENTS

Non-derivative financial instruments

Fair value of non-derivative financial instruments

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

Available for sale assets are recorded at fair value which is calculated using quoted market prices where available. Certain non-derivative financial instruments included in cash and cash equivalents, accounts receivable, intangible and other assets, notes payable, accounts payable and other, 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 Company's non-derivative financial instruments, excluding those where carrying amounts approximate fair value, which would be classified in Level II of the fair value hierarchy:

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

1 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.

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

Available for sale assets summary

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

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

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

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

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

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 September 30, 2017 is as follows:

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

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 September 30, 2017 (unaudited)	Power	Natural Gas	Liquids	Foreign Exchange	Interest
Purchases[1]	**83,491**	**159**	**8**	**—**	**—**
Sales[1]	**53,727**	**152**	**10**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**US 3,072**	**US 1,550**
Millions of Mexican pesos	**—**	**—**	**—**	**MXN 100**	**—**
Maturity dates	**2017-2022**	**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 Gains/(Losses) on Derivative Instruments

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

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

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

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

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI and AOCI.
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 September 30, 2017 (unaudited - millions of Canadian $)	**Gross derivative instruments presented on the balance sheet**	**Amounts available for offset[1]**	**Net amounts**
Derivative – Asset			
Commodities	**289**	**(220)**	**69**
Foreign exchange	**83**	**(63)**	**20**
Interest rate	**3**	**(1)**	**2**
Total	**375**	**(284)**	**91**
Derivative – Liability			
Commodities	**(361)**	**220**	**(141)**
Foreign exchange	**(244)**	**63**	**(181)**
Interest rate	**(3)**	**1**	**(2)**
Total	**(608)**	**284**	**(324)**

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

Credit risk related contingent features of derivative instruments

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

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

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

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 at September 30, 2017, are categorized as follows:

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

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

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

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

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

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

12. Acquisitions & Dispositions

Mexico Natural Gas Pipelines

TransGas

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

Canadian Natural Gas Pipelines

Prince Rupert Gas Transmission

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

U.S. Natural Gas Pipelines

Iroquois Gas Transmission System and Portland Natural Gas Transmission System

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

Columbia Pipeline Group

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

Energy

U.S. Northeast Power Assets

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

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

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

13. Commitments, contingencies and guarantees

COMMITMENTS

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

CONTINGENCIES

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

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

14. Variable interest entities

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

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

Consolidated VIEs

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

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

(unaudited - millions of Canadian $)	September 30, 2017	December 31, 2016
ASSETS		
Current Assets		
Cash and cash equivalents	**91**	77
Accounts receivable	**56**	71
Inventories	**22**	25
Other	**8**	10
	177	183
Plant, Property and Equipment	**3,552**	3,685
Equity Investments	**923**	606
Goodwill	**489**	525
Intangible and Other Assets	**—**	1
	5,141	5,000
LIABILITIES		
Current Liabilities		
Accounts payable and other	**80**	80
Accrued interest	**30**	21
Current portion of long-term debt	**87**	76
	197	177
Regulatory Liabilities	**33**	34
Other Long-Term Liabilities	**3**	4
Deferred Income Tax Liabilities	**13**	7
Long-Term Debt	**3,349**	2,827
	3,595	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 entities or where this power is shared with third parties. The Company contributes capital to these VIEs and receives ownership interests that provide it with residual claims on assets after liabilities are paid.

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

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

15. Subsequent event

Energy East and Related Projects

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