TransCanada Reports Record Third Quarter Financial Results
Funding Complete for 2018 Capital Program

CALGARY, Alberta – **November 1, 2018** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced net income attributable to common shares for third quarter 2018 of $928 million or $1.02 per share compared to net income of $612 million or $0.70 per share for the same period in 2017. Comparable earnings for third quarter 2018 were $902 million or $1.00 per share compared to $614 million or $0.70 per share for the same period in 2017. TransCanada's Board of Directors also declared a quarterly dividend of $0.69 per common share for the quarter ending December 31, 2018, equivalent to $2.76 per common share on an annualized basis.

"During the third quarter of 2018, our diversified portfolio of critical energy infrastructure assets continued to perform extremely well," said Russ Girling, TransCanada's president and chief executive officer. "Comparable earnings of $1.00 per share increased 43 per cent compared to the same period last year reflecting the strong performance of our legacy assets, contributions from approximately $7 billion of growth projects that entered service over the last twelve months and the positive impact of U.S. Tax Reform. For the nine months ended September 30, 2018, comparable earnings were $2.82 per share, an increase of 24 per cent over the same period last year despite the sale of our U.S. Northeast power generation and Ontario solar assets in 2017 and necessary financing activities that have us on track to return to long-term targeted credit metrics post the Columbia acquisition."

"With our existing asset portfolio benefiting from strong underlying market fundamentals and approximately $36 billion of secured growth projects underway including Coastal GasLink, NGTL's 2022 expansion program and Bruce Power's Unit 6 refurbishment, earnings and cash flow are forecast to continue to rise. This is expected to support annual dividend growth of eight to ten per cent through 2021," added Girling. "With approximately $10 billion of new projects expected to enter service by early 2019, we are well positioned to fund the remainder of our secured growth program through internally generated cash flow, access to capital markets and further portfolio management activities. Through the end of October, we placed approximately $6.1 billion of long-term debt on compelling terms and raised approximately $2.0 billion of common equity through our dividend reinvestment plan and at-the-market program. We also completed the sale of our interests in the Cartier Wind power facilities for proceeds of approximately $630 million and expect to be reimbursed for approximately $400 million of Coastal GasLink pre-development costs. Collectively these initiatives have raised $9.1 billion which, when combined with our growing internally generated cash flow, means our 2018 financing requirements are fully funded. We view ATM issuance as being complete at this time while our dividend reinvestment plan will operate for some portion of 2019. Going forward, we will continue to evaluate share count growth against further portfolio management activities."

"Looking ahead, we continue to methodically advance more than $20 billion of projects under development including Keystone XL and the Bruce Power life extension agreement. Success in advancing these and/or other growth initiatives associated with our vast, well-positioned North American footprint could extend our growth outlook well into the next decade," concluded Girling.

Highlights

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

- Third quarter 2018 financial results
  - Net income attributable to common shares of $928 million or $1.02 per common share
  - Comparable earnings of $902 million or $1.00 per common share
  - Comparable earnings before interest, taxes, depreciation and amortization of $2.1 billion
  - Net cash provided by operations of $1.3 billion
  - Comparable funds generated from operations of $1.6 billion
  - Comparable distributable cash flow of $1.4 billion or $1.56 per common share reflecting only non-recoverable maintenance capital expenditures
- Declared a quarterly dividend of $0.69 per common share for the quarter ending December 31, 2018
- Announced that we will proceed with construction of the $6.2 billion Coastal GasLink pipeline project
- Announced $1.5 billion NGTL 2022 Expansion Program
- Bruce Power submitted a final estimate for the Unit 6 Major Component Replacement (MCR) program to the Independent Electricity System Operator (IESO) in September 2018; we expect to invest approximately $2.2 billion in this and the ongoing Asset Management program through 2023
- Issued $1.0 billion of 10- and 30-year fixed-rate medium-term notes in July 2018
- Raised US$1.4 billion of 10- and 30-year fixed-rate senior notes in October 2018
- Completed the sale of our interests in Cartier Wind for approximately $630 million in October 2018
- Expect to be reimbursed for $399 million of Coastal GasLink pre-development costs in fourth quarter 2018.

Net income attributable to common shares increased by $316 million or $0.32 per common share to $928 million or $1.02 per share for the three months ended September 30, 2018 compared to the same period last year. Per share results in 2018 reflect the dilutive effect of common shares issued in 2017 and 2018 under our DRP and Corporate ATM program. Third quarter 2018 results included after-tax income of $8 million related to our U.S. Northeast power marketing contracts which were excluded from comparable earnings as we do not consider their wind-down part of our underlying operations. Third quarter 2017 results included a $12 million after-tax loss related to the monetization of our U.S. Northeast power generation assets, an after-tax charge of $30 million for integration-related costs associated with the acquisition of Columbia and an after-tax charge of $8 million related to the maintenance of Keystone XL assets. 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 2018 were $902 million or $1.00 per common share compared to $614 million or $0.70 per common share for the same period in 2017, an increase of $288 million or $0.30 per share and was primarily due to the net effect of:

- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes and the amortization of net regulatory liabilities recognized as a result of U.S. Tax Reform
- higher contribution from Liquids Pipelines primarily due to earnings from intra-Alberta pipelines placed in service in the second half of 2017, increased earnings from liquids marketing activities, and higher volumes on the Keystone Pipeline System
- lower income tax expense primarily due to lower income tax rates as a result of U.S. Tax Reform
- higher revenues from our Mexico operations as a result of changes in timing of revenue recognition
- higher interest expense primarily as a result of long-term debt and junior subordinated notes issuances, net of maturities, and lower capitalized interest.

Notable recent developments include:

Canadian Natural Gas Pipelines:

- ***Coastal GasLink Pipeline (CGL) Project:*** On October 2, 2018, we announced that we will proceed with construction of the CGL pipeline project following the LNG Canada joint venture participants' announcement that they have reached a positive Final Investment Decision (FID) to build the LNG Canada natural gas liquefaction facility in Kitimat, BC. CGL will provide the natural gas supply to the LNG Canada facility and is underpinned by 25-year transportation services agreements (with additional renewal provisions) with the LNG Canada participants. CGL is a 670 km (420 miles) pipeline with an initial capacity of approximately 2.2 PJ/d (2.1 Bcf/d) with potential expansion capacity up to 5.4 PJ/d (5.0 Bcf/d). All necessary regulatory permits have been received to allow us to proceed with construction activities which are expected to begin in January 2019, with a planned in-service date in 2023. CGL has signed project and community agreements with all 20 elected Indigenous bands along the pipeline route, confirming strong support from Indigenous communities across the province of B.C.

  On July 30, 2018, an individual asked the National Energy Board (NEB) to consider whether the CGL pipeline should be federally regulated by the NEB. On October 22, 2018 the NEB advised that it would consider the question of jurisdiction. In the same letter, the NEB set a process to determine whether the individual who raised the question has standing, and to decide on the standing of any other interested parties. The process to consider the jurisdictional question is to be determined and the permits to construct remain valid.

  The capital cost estimate is $6.2 billion with the majority of the construction spend occurring in 2020 and 2021. Subject to terms and conditions, differences between the estimated capital cost and final cost of the project will be recovered in future pipeline tolls. As part of the CGL funding plan, we intend to explore joint venture partners and project financing for the project.

  The total capital cost estimate includes pre-development costs to date of approximately $470 million. In accordance with provisions in the agreements with the LNG Canada joint venture participants, to date, four parties have elected to reimburse us for their share of pre-development costs, totaling $399 million of cost reimbursement, with payments due by November 30, 2018.

- ***NGTL System***: On October 31, 2018, we announced the NGTL 2022 Expansion Program to meet capacity requirements for incremental firm receipt and intra-basin delivery services to commence in November 2021 and April 2022. This $1.5 billion expansion of the NGTL System consists of approximately 197 km (122 miles) of new pipeline, three compressor units, meter stations and associated facilities. Applications for approvals to construct and operate the facilities are expected to be filed with the NEB in second quarter 2019 and, pending receipt of regulatory approvals, construction would start as early as third quarter 2020.

  The NGTL capital program, excluding maintenance capital expenditures, is now approximately $9.1 billion including the $1.5 billion 2022 Expansion Program.

- ***Canadian Mainline:*** On October 9, 2018, we concluded the written hearing process for the Canadian Mainline 2018-2020 toll review with the filing of our reply evidence to the NEB. We have requested a decision by December 31, 2018.

U.S. Natural Gas Pipelines:

- ***WB XPress:*** The Western Build of the WB XPress (WBX) project was placed into service on October 5, 2018. The Eastern Build of WBX remains to be completed, as planned, in fourth quarter 2018.

- ***2018 FERC Actions:*** On March 15, 2018, the Federal Energy Regulatory Commission (FERC) issued (1) a Revised Policy Statement to address the treatment of income taxes for rate-making purposes for master limited partnerships; (2) a Notice of Proposed Rulemaking (NOPR) proposing natural gas pipeline and storage entities file a one-time report to quantify the impact of the federal income tax rate reduction and the impact of the Revised Policy Statement on each entity's return on equity assuming a single-issue adjustment to an entity's rates; and (3) a notice of inquiry seeking comment on how FERC should address changes related to accumulated deferred income taxes and bonus depreciation. On July 18, 2018, FERC issued (1) an Order on Rehearing of the Revised Policy Statement dismissing rehearing requests and (2) a Final Rule adopting and revising procedures from, and clarifying aspects of, the NOPR (Final Rule), (collectively, the "2018 FERC Actions"). The Final Rule became effective September 13, 2018, and is subject to requests for further rehearing and clarification. Each is described more fully in our management's discussion and analysis (MD&A).

Our U.S. natural gas pipelines are held through a number of different ownership structures. We do not anticipate that the earnings and cash flows from our directly-held U.S. natural gas pipelines, including ANR, Columbia Gas and Columbia Gulf, will be materially impacted by the Revised Policy Statement as a significant proportion of their overall revenues are earned under non-recourse rates.

For more information on the impact of the 2018 FERC Actions on TC PipeLines, LP and our U.S. natural gas pipelines held through TC PipeLines, LP, please refer to our MD&A in the 2018 FERC Actions section. As our ownership interest in TC PipeLines, LP is approximately 25 per cent, the impact of the 2018 FERC Actions related to TC PipeLines, LP is not expected to be significant to our consolidated earnings or cash flows.

- ***Rate Settlements:*** In October 2018, Gas Transmission Northwest LLC (GTN) filed with FERC an uncontested settlement with its customers. Please refer to our MD&A in the 2018 FERC Actions section for additional detail.

Mexico Natural Gas Pipelines:

- ***Sur de Texas:*** Offshore construction was completed in May 2018 and the project continues to progress toward an anticipated in-service date at the end of 2018. An amending agreement has been signed with the Comisión Federal de Electricidad (CFE) that recognizes force majeure events and the commencement of payments of fixed capacity charges beginning October 31, 2018.
- ***Tula and Villa de Reyes:*** The CFE has approved the recognition of force majeure events for both of these pipelines, including the continuation of the payment of fixed capacity charges to us that began in first quarter 2018. Construction of the Villa de Reyes project is ongoing and it is anticipated to be in service by the second half of 2019.

Liquids Pipelines:

- ***Keystone XL:*** In December 2017, an appeal to Nebraska's Court of Appeals was filed by intervenors after the Nebraska Public Service Commission (PSC) issued an approval of an alternative route for the Keystone XL project in November 2017. In March 2018, the Nebraska Supreme Court, on its own motion, agreed to bypass the Court of Appeals and directly hear the appeal case against the PSC's alternative route. Legal briefs on the appeal were submitted in May 2018. Oral argument before the Nebraska Supreme Court has been set for November 1, 2018. We expect the Nebraska Supreme Court, as the final arbiter, could reach a decision by first quarter 2019.

  The Keystone XL Presidential Permit, issued in March 2017, has been challenged in two separate lawsuits commenced in Montana. Together with the U.S. Department of Justice (DOJ), we are actively participating in these lawsuits to defend both the issuance of the permit and the exhaustive environmental assessments that support the U.S. President's actions. Legal arguments addressing the merits of these lawsuits were heard in May 2018 and we believe the court's decisions on certain elements of these legal challenges may be issued by the end of 2018.

  On August 15, 2018, the U.S. District Court in Montana issued a Partial Order requiring the DOJ and the U.S. Department of State (DOS) (the Federal Defendants) to prepare a supplemental environmental impact statement (SEIS) to the 2014 Final Supplemental Environmental Impact Statement and a proposed schedule for the completion of the SEIS. On September 4, 2018, the Federal Defendants responded to this Partial Order by filing the required schedule which reflected the issuance of the final SEIS in December 2018. On

September 21, 2018, the DOS issued a draft SEIS which concluded that implementation of the mainline alternative route would have no significant direct, indirect or cumulative effect on the quality of the natural or human environments, having consideration for the mitigation plans proposed by TransCanada. The draft SEIS is open for public comment for a period of 45 days. The Federal Defendants also indicated that the U.S. Bureau of Land Management and the U.S. Army Corps of Engineers would likely issue decisions regarding their respective federal permitting activities in first quarter 2019.

In September 2018, two U.S. Native American communities filed a lawsuit in Montana challenging the Keystone XL Presidential Permit. It is uncertain how and when this lawsuit will proceed.

Energy:

- ***Cartier Wind:*** On October 24, 2018, we completed the sale of our interests in the Cartier Wind power facilities in Québec to Innergex Renewable Energy Inc. for gross proceeds of approximately $630 million before closing adjustments resulting in an estimated gain of $170 million ($135 million after tax) to be recorded in fourth quarter 2018.
- ***Bruce Power - Life Extension:*** On September 28, 2018, Bruce Power submitted its final cost and schedule duration estimate (basis of estimate) for the Unit 6 MCR program to the IESO. The IESO has up to three months to review and verify the basis of estimate. As the cost and schedule duration are both less than the thresholds defined in the program's life extension and refurbishment agreement, no further approvals from the IESO or government are required to proceed with the Unit 6 MCR outage in early 2020. The Unit 6 MCR outage is expected to be completed in late 2023.

  As a result of this filing, we have updated our project cost estimates in our Capital Program tables to reflect our expected investment of approximately $2.2 billion (in nominal dollars) in Bruce Power's Unit 6 MCR program and ongoing Asset Management (AM) program through 2023, and approximately $6.0 billion (in 2018 dollars) for the remaining five-unit MCR program and the AM program beyond 2023. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available for Bruce Power and the IESO.

  Bruce Power's current contract price of approximately $68 per MWh will be increased in April 2019 to reflect capital to be invested under the Unit 6 MCR program and the AM program as well as normal annual inflation adjustments.
- ***Napanee:*** Construction continues on our 900 MW natural gas-fired power plant at Ontario Power Generation's (OPG) Lennox site in eastern Ontario in the town of Greater Napanee. We expect our total investment in the Napanee facility will be approximately $1.6 billion and commercial operations are expected to begin in first quarter 2019. Costs have increased due to delays in the construction schedule. Once in service, production from the facility is fully contracted with the IESO for a 20-year period.

Corporate:

- ***Common Share Dividend:*** Our Board of Directors declared a quarterly dividend of $0.69 per share for the quarter ending December 31, 2018 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $2.76 per common share on an annualized basis.
- ***Issuance of Long-term Debt:*** In October 2018, TCPL issued US$1.0 billion of Senior Unsecured Notes due in March 2049 bearing interest at a fixed rate of 5.10 per cent and US$400 million of Senior Unsecured Notes due in May 2028 bearing interest at a fixed rate of 4.25 per cent.

  In third quarter 2018, TCPL issued $800 million of Medium Term Notes due in July 2048 bearing interest at a fixed rate of 4.18 per cent and $200 million of Medium Term Notes due in March 2028 bearing interest at a fixed rate of 3.39 per cent.

The net proceeds of the above debt issuances were used for general corporate purposes, to fund our capital program and to pre-fund 2019 senior note maturities.

In third quarter 2018, TCPL repaid US$850 million of Senior Unsecured Notes bearing interest at a fixed rate of 6.50 per cent.

- *Dividend Reinvestment Plan:* In third quarter 2018, the DRP participation rate amongst common shareholders was approximately 34 per cent, resulting in $213 million reinvested in common equity under the program. Year-to-date in 2018, the participation rate amongst common shareholders has been approximately 35 per cent, resulting in $655 million of dividends reinvested.
- *ATM Equity Program:* In third quarter 2018, 6.1 million common shares were issued under our Corporate ATM program at an average price of $57.75 per common share for proceeds of $351 million, net of related commissions and fees of approximately $3 million. In the nine months ended September 30, 2018, 20.0 million common shares have been issued under our Corporate ATM program at an average price of $56.13 per common share for proceeds of $1.1 billion, net of approximately $10 million of related commissions and fees.

Teleconference and Webcast:

We will hold a teleconference and webcast on Thursday, November 1, 2018 to discuss our third quarter 2018 financial results. Russ Girling, 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 8 a.m. (MT) / 10 a.m. (ET).

Members of the investment community and other interested parties are invited to participate by calling 800.377.0758 or 416.340.2219 (Toronto area). Please dial in 10 minutes prior to the start of the call. No pass code is required. A live webcast of the teleconference will be available at www.transcanada.com or via the following URL: www.gowebcasting.com/9680.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (ET) on November 8, 2018. Please call 800.408.3053 or 905.694.9451 (Toronto area) and enter pass code 1642917#.

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 one of the largest natural gas transmission networks that extends more than 91,900 kilometres (57,100 miles), tapping into virtually all major gas supply basins in North America. TransCanada is a leading 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 5,700 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 4,900 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 www.transcanada.com to learn more, or connect with us on social 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 October 31, 2018 and the 2017 Annual Report filed under TransCanada's profile on SEDAR at www.sedar.com and with the U.S. Securities and Exchange Commission at www.sec.gov.

Non-GAAP Measures

This news release contains references to non-GAAP measures, including comparable earnings, comparable earnings per common share, comparable EBITDA, comparable distributable cash flow, comparable distributable cash flow per common share and comparable funds generated from operations, 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 except as otherwise described in the Condensed consolidated financial statements and MD&A. For more information on non-GAAP measures, refer to TransCanada's Quarterly Report to Shareholders dated October 31, 2018.

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Quarterly report to shareholders

Third quarter 2018

Financial highlights

(unaudited - millions of $, except per share amounts)	three months ended September 30		nine months ended September 30	
	2018	**2017**	**2018**	**2017**
Income				
Revenues	**3,156**	3,195	**9,775**	9,832
Net income attributable to common shares	**928**	612	**2,447**	2,136
per common share – basic	**$1.02**	$0.70	**$2.72**	$2.46
– diluted	**$1.02**	$0.70	**$2.72**	$2.45
Comparable EBITDA[1]	**2,056**	1,667	**6,110**	5,474
Comparable earnings[1]	**902**	614	**2,534**	1,971
per common share[1]	**$1.00**	$0.70	**$2.82**	$2.27
Cash flows				
Net cash provided by operations	**1,299**	1,185	**4,516**	3,840
Comparable funds generated from operations[1]	**1,571**	1,316	**4,641**	4,191
Comparable distributable cash flow[1]	**1,413**	1,170	**4,158**	3,691
per common share[1]	**$1.56**	$1.34	**$4.63**	$4.24
Capital spending[2]	**2,798**	2,543	**7,491**	6,658
Dividends declared				
Per common share	**$0.69**	$0.625	**$2.07**	$1.875
Basic common shares outstanding (millions)				
– weighted average for the period	**906**	873	**898**	870
– issued and outstanding at end of period	**914**	874	**914**	874

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.

2 Includes capital expenditures, capital projects in development and contributions to equity investments.

Management's discussion and analysis

October 31, 2018

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, 2018, and should be read with the accompanying unaudited condensed consolidated financial statements for the three and nine months ended September 30, 2018, which have been prepared in accordance with U.S. GAAP.

This MD&A should also be read in conjunction with our December 31, 2017 audited consolidated financial statements and notes and the MD&A in our 2017 Annual Report. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in our 2017 Annual Report. Certain comparative figures have been adjusted to reflect the current period's presentation.

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
- 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, including the expected impact of the 2018 FERC Actions
- 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 impact of U.S. Tax Reform
- 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

- continued wind-down of our U.S. Northeast power marketing business
- inflation rates and commodity prices
- nature and scope of hedging activities
- regulatory decisions and outcomes, including those related to the 2018 FERC Actions
- interest, tax and foreign exchange rates, including the impact of U.S. Tax Reform
- 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 from our energy business
- regulatory decisions and outcomes, including those related to the 2018 FERC Actions
- 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, including the impact of U.S. Tax Reform
- weather
- cyber security
- technological developments
- economic conditions in North America as well as globally.

You can read more about these factors and others in this MD&A and in other disclosure documents we have filed with Canadian securities regulators and the SEC, including the MD&A in our 2017 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. Except as otherwise described herein, these comparable measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable.

Our decision not to adjust for a specific item is subjective and made after careful consideration. Specific items may include:

- certain fair value adjustments relating to risk management activities
- income tax refunds and adjustments and changes to enacted tax rates
- gains or losses on sales of assets or assets held for sale
- legal, contractual and bankruptcy settlements
- impact of regulatory or arbitration decisions relating to prior year earnings
- restructuring costs
- impairment of property, plant and equipment, 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 most directly comparable 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 represents 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 specific items. See the Consolidated results section for reconciliations to net income attributable to common shares and net income per common share.

Comparable EBIT and comparable EBITDA

Comparable EBIT represents segmented earnings, adjusted for specific items. We use comparable EBIT as a measure of our earnings from ongoing operations as it is a useful indicator 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. 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 non-recoverable 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. We have the opportunity to recover effectively all of our pipeline maintenance capital expenditures in Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Liquids Pipelines through tolls. Canadian natural gas pipelines maintenance capital expenditures are reflected in rate bases, on which we earn a regulated return and subsequently recover in tolls. Our U.S. natural gas pipelines can recover maintenance capital expenditures through tolls under current rate settlements, or have the ability to recover such expenditures through tolls established in future rate cases or settlements. Tolling arrangements in our liquids pipelines provide for the recovery of maintenance capital expenditures. As such, in 2018 our presentation of comparable distributable cash flow and comparable distributable cash flow per common share only includes a reduction for non-recoverable maintenance capital expenditures in their respective calculations. Comparative figures have been adjusted to reflect this presentation.

See the Financial condition section for a reconciliation to net cash provided by operations.

Consolidated results - third quarter 2018

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $, except per share amounts)	**2018**	**2017**	**2018**	**2017**
Canadian Natural Gas Pipelines	**267**	316	**800**	903
U.S. Natural Gas Pipelines	**545**	337	**1,734**	1,299
Mexico Natural Gas Pipelines	**127**	95	**382**	333
Liquids Pipelines	**316**	203	**1,047**	681
Energy	**223**	237	**464**	1,080
Corporate	**(68)**	(29)	**(77)**	(102)
Total segmented earnings	**1,410**	1,159	**4,350**	4,194
Interest expense	**(577)**	(504)	**(1,662)**	(1,528)
Allowance for funds used during construction	**147**	145	**365**	367
Interest income and other	**168**	84	**139**	193
Income before income taxes	**1,148**	884	**3,192**	3,226
Income tax expense	**(120)**	(188)	**(394)**	(781)
Net income	**1,028**	696	**2,798**	2,445
Net income attributable to non-controlling interests	**(59)**	(44)	**(229)**	(189)
Net income attributable to controlling interests	**969**	652	**2,569**	2,256
Preferred share dividends	**(41)**	(40)	**(122)**	(120)
Net income attributable to common shares	**928**	612	**2,447**	2,136
Net income per common share — basic	**$1.02**	$0.70	**$2.72**	$2.46
— diluted	**$1.02**	$0.70	**$2.72**	$2.45

Net income attributable to common shares increased by $316 million and $311 million, or $0.32 and $0.26 per common share, for the three and nine months ended September 30, 2018 compared to the same periods in 2017. Net income per common share in 2018 reflects the dilutive impact of common shares issued in 2017 and 2018 under our DRP and Corporate ATM program.

Net income in both periods included unrealized gains and losses from changes in risk management activities, which we exclude, along with other specific items as noted below to arrive at comparable earnings.

2018 results included:

- after-tax income of $8 million and $3 million for the three and nine months ended September 30, 2018 related to our U.S. Northeast power marketing contracts primarily due to income recognized on the sale of our retail contracts in first quarter and earnings from the remaining contracts. These amounts have been excluded from Energy's comparable earnings effective January 1, 2018 as we do not consider the wind-down of the remaining contracts part of our underlying operations. The contract portfolio is scheduled to run-off through to mid-2020.

2017 results included:

- a $12 million after-tax loss and a $243 million after-tax gain, for the three and nine months ended September 30, 2017, related to the monetization of our U.S. Northeast power generation assets. This 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 was expensed in 2017 pending further advancement of the project. In 2018, Keystone XL expenditures are being capitalized
- 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 reconciliation of net income attributable to common shares to comparable earnings is shown in the following table.

RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $, except per share amounts)	**2018**	**2017**	**2018**	**2017**
Net income attributable to common shares	**928**	612	**2,447**	2,136
Specific items (net of tax):				
U.S. Northeast power marketing contracts	**(8)**	—	**(3)**	—
Net loss/(gain) on sales of U.S. Northeast power generation assets	**—**	12	**—**	(243)
Integration and acquisition related costs – Columbia	**—**	30	**—**	69
Keystone XL asset costs	**—**	8	**—**	19
Keystone XL income tax recoveries	**—**	—	**—**	(7)
Risk management activities[1]	**(18)**	(48)	**90**	(3)
Comparable earnings	**902**	614	**2,534**	1,971
Net income per common share — basic	**$1.02**	$0.70	**$2.72**	$2.46
Specific items (net of tax):				
U.S. Northeast power marketing contracts	**(0.01)**	—	**—**	—
Net loss/(gain) on sales of U.S. Northeast power generation assets	**—**	0.01	**—**	(0.28)
Integration and acquisition related costs – Columbia	**—**	0.03	**—**	0.08
Keystone XL asset costs	**—**	0.01	**—**	0.02
Keystone XL income tax recoveries	**—**	—	**—**	(0.01)
Risk management activities	**(0.01)**	(0.05)	**0.10**	—
Comparable earnings per common share	**$1.00**	$0.70	**$2.82**	$2.27

1

Risk management activities	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Canadian Power	**—**	1	**3**	5
U.S. Power	**31**	59	**(31)**	(97)
Liquids marketing	**(65)**	(19)	**(10)**	(15)
Natural Gas Storage	**—**	4	**(6)**	5
Interest rate	**—**	(1)	**—**	(1)
Foreign exchange	**60**	33	**(79)**	89
Income tax attributable to risk management activities	**(8)**	(29)	**33**	17
Total unrealized gains/(losses) from risk management activities	**18**	48	**(90)**	3

Comparable earnings increased by $288 million or $0.30 per common share for the three months ended September 30, 2018 compared to the same period in 2017 and was primarily the net effect of:

- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes and the amortization of net regulatory liabilities recognized as a result of U.S. Tax Reform
- higher contribution from Liquids Pipelines primarily due to earnings from intra-Alberta pipelines placed in service in the second half of 2017, increased earnings from liquids marketing activities, and higher volumes on the Keystone Pipeline System
- lower income tax expense primarily due to lower income tax rates as a result of U.S. Tax Reform
- higher revenues from our Mexico operations as a result of changes in timing of revenue recognition
- higher interest expense primarily as a result of long-term debt and junior subordinated notes issuances, net of maturities, and lower capitalized interest.

Comparable earnings increased by $563 million or $0.55 per common share for the nine months ended September 30, 2018 compared to the same period in 2017 and was primarily the net effect of:

- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes and amortization of net regulatory liabilities recognized as a result of U.S. Tax Reform
- higher contribution from Liquids Pipelines primarily due to earnings from intra-Alberta pipelines placed in service in the second half of 2017, increased earnings from liquids marketing activities, and higher volumes on the Keystone Pipeline System
- lower income tax expense primarily due to lower income tax rates as a result of U.S. Tax Reform
- higher revenues from our Mexico operations as a result of changes in timing of revenue recognition
- increased Western Power results due to higher realized margins on higher generation volumes
- lower earnings from U.S. Power mainly due to the sales of the U.S. Northeast power generation assets in second quarter 2017 combined with the U.S. Northeast Power marketing results being excluded from comparable earnings in 2018
- higher interest expense primarily as a result of long-term debt and junior subordinated notes issuances, net of maturities, and lower capitalized interest, partially offset by the repayment of the Columbia acquisition bridge facilities in June 2017
- lower earnings from Bruce Power primarily due to lower volumes resulting from increased outage days and lower earnings from contracting activities
- lower Eastern Power results mainly due to the sale of our Ontario solar assets in December 2017.

Comparable earnings per common share for the three and nine months ended September 30, 2018 also reflect the dilutive impact of common shares issued in 2017 and 2018 under our DRP and our Corporate ATM program.

2018 FERC Actions

BACKGROUND

In December 2016, FERC issued a Notice of Inquiry (NOI) seeking comment on how to address the issue of whether its existing policies resulted in a 'double recovery' of income taxes in a pass-through entity such as a master limited partnership (MLP). This NOI was in response to a decision by the U.S. Court of Appeals for the District of Columbia Circuit in July 2016 in United Airlines, Inc., et al. v. FERC (the United case), directing FERC to address the issue.

On December 22, 2017, U.S. Tax Reform was signed resulting in significant changes to U.S. tax law including a decrease in the U.S. federal corporate income tax rate from 35 per cent to 21 per cent effective January 1, 2018. As a result of this change, accumulated deferred income tax (ADIT) assets and liabilities related to our U.S. businesses, including amounts related to our proportionate share of assets held in TC PipeLines, LP, were remeasured as at December 31, 2017 to reflect the new lower U.S. federal corporate income tax rate. With respect to our U.S. rate-regulated natural gas pipelines and storage entities, the impact of this remeasurement was recorded as a net regulatory liability.

On March 15, 2018, FERC issued (1) a Revised Policy Statement to address the treatment of income taxes for rate-making purposes for MLPs; (2) a Notice of Proposed Rulemaking (NOPR) proposing natural gas pipeline and storage entities file a one-time report to quantify the impact of the federal income tax rate reduction and the impact of the Revised Policy Statement on each entity's ROE assuming a single-issue adjustment to an entity's rates; and (3) a NOI seeking comment on how FERC should address changes related to ADIT and bonus depreciation. On July 18, 2018, FERC issued (1) an Order on Rehearing of the Revised Policy Statement dismissing rehearing requests; and (2) a Final Rule adopting and revising procedures from, and clarifying aspects of, the NOPR (Final Rule), (collectively, the "2018 FERC Actions"). The Final Rule became effective September 13, 2018, and is subject to requests for further rehearing and clarification. The impacts of the Final Rule relate to both FERC-regulated natural gas pipeline and gas storage assets. Discussion within this 2018 FERC Actions section describes the impact to our natural gas pipelines, but also applies to our FERC-regulated natural gas storage assets.

FERC Revised Policy Statement on Treatment of Income Taxes for MLPs

The Revised Policy Statement changes FERC's long-standing policy allowing income tax amounts to be included in rates subject to cost-of-service rate regulation for pipelines owned by an MLP. The Revised Policy Statement creates a presumption that entities whose earnings are not taxed through a corporation should not be permitted to recover an income tax allowance in their regulated cost-of-service rates. On July 18, 2018, FERC dismissed requests for rehearing and provided clarification of the Revised Policy Statement. In this Order on Rehearing, FERC noted that an MLP is not automatically precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance in its cost-of-service rates. Additionally, FERC provided guidance with regard to ADIT for MLP pipelines and other pass-through entities. FERC found that to the extent an entity's income tax allowance should be eliminated from rates, it must also eliminate its existing ADIT balance from its rate base. As a result, the Revised Policy Statement also precludes the recognition and subsequent amortization of any related regulatory assets or liabilities that might have otherwise impacted rates charged to customers as a refund or collection of excess or deficient deferred income tax assets or liabilities.

Final Rule on Tax Law Changes for Interstate Natural Gas Pipelines and Storage Entities

The Final Rule established a schedule by which interstate pipelines must either (i) file a new uncontested rate settlement or (ii) file a one-time report, called FERC Form 501-G, that quantifies the isolated rate impact of U.S. Tax Reform on FERC-regulated pipelines and the impact of the Revised Policy Statement on pipelines held by MLPs. A pipeline filing the FERC Form 501-G must do so by established dates in fourth quarter 2018 and will have four options:

- make a limited Natural Gas Act (NGA) Section 4 filing to reduce its rates by the reduction in its cost-of-service shown in its FERC Form 501-G. For any pipeline electing this option, FERC guarantees a three-year moratorium on NGA Section 5 rate investigations if the pipeline's FERC Form 501-G shows the pipeline's estimated ROE as being 12 per cent or less. Under the Final Rule, and notwithstanding the Revised Policy Statement discussed above, a pipeline organized as an MLP is not required to eliminate its income tax allowance, but instead can reduce its rates to reflect the reduction in the maximum corporate tax rate. Alternatively, the MLP pipeline can eliminate its tax allowance along with its ADIT used for rate-making purposes. In situations where the ADIT balance is a liability, this elimination would have the effect of increasing the pipeline's rate base for rate-making purposes
- commit to file either a pre-packaged uncontested rate settlement or a general Section 4 rate case if it believes that using the limited Section 4 option will not result in just and reasonable rates. If the pipeline commits to file either by December 31, 2018, FERC will not initiate a Section 5 investigation of its rates prior to that date
- file a statement explaining its rationale for why it does not believe the pipeline's rates must change; or
- take no other action. FERC will consider whether to initiate a Section 5 investigation of any pipeline that has not submitted a limited Section 4 rate filing or committed to file a general Section 4 rate case.

NOI Regarding the Effect of U.S. Tax Reform on Commission-Jurisdictional Rates

In the NOI, FERC sought comment on the effects of U.S. Tax Reform to determine additional action, if any, required by FERC related to ADIT balances that were reserved in anticipation of being paid to or refunded by the Internal Revenue Service, but which no longer accurately reflect the future income tax liability or asset. The NOI also sought comment on the elimination of bonus depreciation for regulated natural gas pipelines and other effects of U.S. Tax Reform on regulated rates or earnings.

As noted above, FERC's Order on Rehearing of the Revised Policy Statement provided guidance with regard to ADIT for MLP pipelines, finding that if an MLP pipeline's income tax allowance is eliminated from its cost-of-service rates, then its existing ADIT balance used for rate-making purposes should also be eliminated from its rate base.

IMPACT OF 2018 FERC ACTIONS ON TRANSCANADA

Our U.S. natural gas pipelines are held through a number of different ownership structures. We do not anticipate that the earnings and cash flows from our directly-held U.S. natural gas pipelines, including ANR, Columbia Gas and Columbia Gulf, will be materially impacted by the Revised Policy Statement as a significant proportion of their overall revenues are earned under non-recourse rates. Columbia Gas is required under existing settlements to adjust certain of its recourse rates for the decrease in the U.S. federal corporate income tax rate enacted December 22, 2017, with the changes implemented January 1, 2018. As ANR, Columbia Gas, Columbia Gulf and other wholly-owned regulated assets undergo future rate proceedings, future rates may be impacted prospectively as a result of U.S. Tax Reform, but the impact is expected to be largely mitigated by lower corporate income tax rates. Therefore, the impact on earnings and cash flows resulting from the 2018 FERC Actions on our U.S. natural gas pipelines held outside of TC PipeLines, LP is expected to be limited in comparison to pre-U.S. Tax Reform.

The following is an update on our filings outside of TC Pipelines, LP, in response to the Final Rule subsequent to September 30, 2018:

- Millennium Pipeline filed its Form 501-G October 11, 2018
- ANR, ANR Storage, Columbia Gas, Columbia Gulf and Crossroads are scheduled to file their respective Form 501-Gs on December 6, 2018 unless new uncontested rate settlements are filed

- Hardy Storage and Blue Lake Storage have reached rate settlements in principle. We expect to file the settlement agreements with FERC in fourth quarter 2018. As outlined in 2018 FERC Actions, pipeline and storage assets that file an uncontested settlement will be relieved of their obligations to file a Form 501-G.

The Revised Policy Statement also prohibits an income tax allowance for liquids pipelines held in MLP structures. We do not expect an impact on our U.S. liquids pipelines as they are not held in MLP form.

Financing

In March 2018, as a result of the initially proposed 2018 FERC Actions, further drop downs of assets into TC PipeLines, LP were considered to no longer be a viable funding lever. In addition, the TC PipeLines, LP ATM program ceased to be utilized. Pursuant to the 2018 FERC Actions issued on July 18, 2018, it is yet to be determined if and when in the future these might be restored as competitive financing options. Regardless, we believe we have the financial capacity to fund our existing capital program through predictable and growing cash flow generated from operations, access to capital markets including through our Corporate ATM program and our DRP, portfolio management, cash on hand and substantial committed credit facilities.

Impact of 2018 FERC Actions on TC PipeLines, LP

On October 16, 2018, GTN filed with FERC an uncontested settlement with its customers to address the changes proposed by the 2018 FERC Actions via an amendment to its prior settlement in 2015 ("2018 GTN Settlement"). Among the terms of the latest settlement, GTN has agreed to (i) a refund of US$10 million to its firm customers in 2018, (ii) a reduction to its existing maximum system reservation rates by 10 per cent effective January 1, 2019, and (iii) an additional 6.6 per cent reduction effective January 1, 2020 through December 31, 2021. GTN and its customers have also agreed upon a moratorium on further rate changes prior to January 1, 2022. The uncontested settlement, subject to approval by the FERC, will relieve GTN of its obligation to file a Form 501-G.

The following is an update on other TC PipeLines, LP filings in response to the Final Rule subsequent to September 30, 2018:

- PNGTS filed its Form 501-G with FERC along with an explanation why no rate change is needed
- North Baja elected to make a limited NGA Section 4 filing and reduce its recourse rates by approximately 11 per cent, which is the percentage reduction in the cost of service per the FERC Form 501-G
- Iroquois requested a waiver of its requirement to file a Form 501-G from FERC based on its existing moratorium precluding rate changes prior to September 2020
- Bison is scheduled to file its response by November 8, 2018 and Northern Border, Great Lakes and Tuscarora are scheduled to file by December 6, 2018.

Following the 2018 GTN Settlement, TC PipeLines, LP's earnings, cash flows and financial position are less adversely impacted by the 2018 FERC Actions than initially expected. A number of uncertainties still exist with respect to the variability of outcomes around the ultimate resolution of the issues arising from the 2018 FERC Actions, but any additional impact in 2018 is expected to be limited for TC PipeLines, LP while subsequent periods could be more significantly affected. Mitigating this impact, approximately half of TC PipeLines, LP's revenues, including those of equity investments, are earned under non-recourse rates which are not expected to be impacted by the 2018 FERC Actions. Furthermore, as our ownership in TC PipeLines, LP is approximately 25 per cent, the impact of the 2018 FERC Actions related to TC PipeLines, LP is not expected to be significant to TransCanada's consolidated earnings or cash flows.

Individual pipelines owned by TC PipeLines, LP do not currently have a requirement to file for new rates until 2022, however, that timing may be accelerated by the Final Rule, except where moratoria exist. As noted above, the change in the Final Rule to allow MLPs to remove the ADIT liability from rate base, thus increasing rate base in general, is expected to further mitigate the loss of the tax allowance in cost-of-service based rates.

As a result of the 2018 FERC Actions initially proposed in March 2018, and in order to retain cash in anticipation of a possible reduction of revenues, TC PipeLines, LP reduced its quarterly distribution to common unitholders by 35 per cent to US$0.65 per unit beginning with its first quarter 2018 distribution.

Impairment Considerations

We review plant, property and equipment and equity investments for impairment whenever events or changes in circumstances indicate the carrying value of the asset may not be recoverable.

Goodwill is tested for impairment on an annual basis, or more frequently if events or changes in circumstance indicate that it might be impaired. We can initially make this assessment based on qualitative factors. If we conclude that it is not more likely than not that the fair value of the reporting unit is less than its carrying value, then an impairment test is not performed.

We continue to monitor developments following the Final Rule on the 2018 FERC Actions. We will incorporate results to date, future filings for individual pipelines, as well as FERC responses to others in the industry into our annual goodwill impairment tests as well as our normal review of plant, property and equipment and equity investments for recoverability.

As at September 30, 2018, the goodwill balances related to Great Lakes and Tuscarora are US$573 million and US$82 million (December 31, 2017 – US$573 million and US$82 million), respectively. At December 31, 2017, the estimated fair value of Great Lakes exceeded its carrying value by less than 10 per cent. There is a risk that the goodwill balances related to both of these assets could be negatively impacted by the FERC developments, once finalized, or by other changes in management's estimates of fair value resulting in a goodwill impairment charge.

U.S. Tax Reform

Pursuant to the enactment of U.S. Tax Reform, we recorded net regulatory liabilities and a corresponding reduction in net deferred income tax liabilities in the amount of $1,686 million at December 31, 2017 related to our U.S. natural gas pipelines subject to RRA. Amounts recorded to adjust income taxes remain provisional as our interpretation, assessment and presentation of the impact of U.S. Tax Reform may be further clarified with additional guidance from tax authorities. Should additional guidance be provided by tax authorities during the one-year measurement period permitted by the SEC, we will review the provisional amounts and adjust as appropriate.

Commencing January 1, 2018, we have amortized the net regulatory liabilities using the Reverse South Georgia methodology. Under this methodology, rate-regulated entities determine and immediately begin recording amortization based on their composite depreciation rates. For the three and nine months ended September 30, 2018, amortization of the net regulatory liabilities in the amount of $12 million and $36 million was recorded and included in Revenues. Once the final impact of the 2018 FERC Actions is determined there may be prospective adjustments to our net regulatory liabilities.

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 flows.

Our capital program consists of approximately $36 billion of secured projects and approximately $20 billion of projects under development. Our secured projects include commercially supported, committed projects that are either under construction or that are in or preparing to commence the permitting stage but are not yet fully approved. Our projects under development are commercially supported except where noted, but have greater uncertainty with respect to timing and estimated project costs and are subject to certain approvals.

Three years of maintenance capital expenditures for all of our businesses are also included in the secured projects table. Maintenance capital expenditures on our regulated Canadian and U.S. natural gas pipelines are added to rate base on which we have the opportunity to earn a return and recover these expenditures through current or future tolls, which is similar to our capacity capital projects on these pipelines. Tolling arrangements in Liquids Pipelines provide for the recovery of maintenance capital expenditures.

All projects are subject to cost adjustments due to weather, market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits, among other factors. Amounts presented in the following tables exclude capitalized interest and AFUDC.

Secured projects

(unaudited - billions of $)	Expected in-service date	Estimated project cost[1]	Carrying value at September 30, 2018
Canadian Natural Gas Pipelines			
Canadian Mainline	2018-2021	0.2	0.1
NGTL System	2018	0.6	0.5
	2019	2.8	0.8
	2020	1.7	0.1
	2021	2.5	—
	2022	1.5	—
Coastal GasLink[2,3]	2023	6.2	0.5
Regulated maintenance capital expenditures	2018-2020	1.9	0.5
U.S. Natural Gas Pipelines			
Columbia Gas			
Mountaineer XPress	2018	US 3.0	US 2.2
WB XPress	2018	US 0.9	US 0.8
Modernization II	2018-2020	US 1.1	US 0.4
Buckeye XPress	2020	US 0.2	—
Columbia Gulf			
Gulf XPress	2018	US 0.6	US 0.5
Other	2018-2020	US 0.3	US 0.2
Regulated maintenance capital expenditures	2018-2020	US 1.9	US 0.4
Mexico Natural Gas Pipelines			
Sur de Texas[4]	2018	US 1.4	US 1.3
Villa de Reyes[4]	2019	US 0.8	US 0.6
Tula[4]	2020	US 0.7	US 0.6
Liquids Pipelines			
White Spruce	2019	0.2	0.1
Recoverable maintenance capital expenditures	2018-2020	0.1	—
Energy			
Napanee	2019	1.6	1.4
Bruce Power – life extension[5]	2018-2023	2.2	0.5
Other			
Non-recoverable maintenance capital expenditures[6]	2018-2020	0.8	0.2
		33.2	**11.7**
Foreign exchange impact on secured projects[7]		**3.2**	**2.0**
Total secured projects (Cdn$)		**36.4**	**13.7**

1 Amounts reflect our proportionate share of joint venture costs where applicable and 100 per cent of costs related to wholly-owned assets and assets held through TC PipeLines, LP.
2 Represents 100 per cent of required capital prior to potential joint venture partners or project financing.
3 Carrying value excludes the reduction for the fourth quarter 2018 elections made to date by certain LNG Canada participants to reimburse approximately $0.4 billion of pre-development costs pursuant to project agreements. Refer to the Recent Developments section for additional details.
4 The CFE has recognized force majeure events for these pipelines and approved the payment of fixed capacity charges in accordance with their respective TSAs. These payments will begin to be recognized as revenue when the pipelines are placed in service.
5 Reflects our proportionate share of the Unit 6 Major Component Replacement program costs, expected to be in service in 2023, and amounts to be invested under the Asset Management program through 2023.
6 Includes non-recoverable maintenance capital expenditures from all segments and is primarily comprised of our proportionate share of maintenance capital expenditures for Bruce Power and other Energy amounts.
7 Reflects U.S./Canada foreign exchange rate of 1.29 at September 30, 2018.

Projects under development

The costs provided in the table below reflect the most recent estimates for each project as filed with the various regulatory authorities or otherwise determined.

(unaudited - billions of $)	**Estimated project cost**[1]	**Carrying value at September 30, 2018**
Canadian Natural Gas Pipelines		
NGTL System – Merrick	1.9	—
Liquids Pipelines		
Heartland and TC Terminals[2,3]	0.9	0.1
Grand Rapids Phase 2[2,3]	0.7	—
Keystone XL[4]	US 8.0	US 0.4
Keystone Hardisty Terminal[2,3,4]	0.3	0.1
Energy		
Bruce Power – life extension[5]	6.0	—
	17.8	0.6
Foreign exchange impact on projects under development[6]	2.3	0.1
Total projects under development (Cdn$)	**20.1**	**0.7**

1 Amounts reflect our proportionate share of joint venture costs where applicable and 100 per cent of costs related to wholly-owned assets.

2 Regulatory approvals have been obtained.

3 Additional commercial support is being pursued.

4 Carrying value reflects amount remaining after impairment charge recorded in 2015, along with additional amounts capitalized from January 1, 2018.

5 Reflects our proportionate share of Major Component Replacement program costs for Units 3, 4, 5, 7 and 8, and the remaining Asset Management program costs beyond 2023.

6 Reflects U.S./Canada foreign exchange rate of 1.29 at September 30, 2018.

Outlook

Consolidated comparable earnings

In fourth quarter 2018, we expect continued strong performance across our business segments consistent with the results reported in the first nine months of 2018. Our overall comparable earnings outlook for 2018 has increased compared to what was included in the 2017 Annual Report primarily due to the net effect of:

- improved earnings from additional contract sales in U.S. Natural Gas Pipelines
- higher contracted and uncontracted volumes on the Keystone Pipeline System as well as higher contributions from liquids marketing activities
- increased revenues in Mexico Natural Gas Pipelines
- increased benefit from and better visibility into the impacts of U.S. Tax Reform
- the sale of our 62 per cent share of the Cartier Wind power facilities.

The 2018 FERC Actions are not anticipated to have a significant impact on our earnings or cash flows in 2018. Refer to the 2018 FERC Actions section for additional details.

Consolidated capital spending

We expect to spend approximately $10.5 billion in 2018 on growth projects, maintenance capital expenditures and contributions to equity investments. The increase from the amount included in the 2017 Annual Report primarily reflects incremental spending required to complete construction of our secured projects capital program in 2018, as well as the capitalization of costs to further advance our projects under development.

Canadian Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
NGTL System	**302**	256	**884**	722
Canadian Mainline	**195**	263	**592**	774
Other[1]	**25**	25	**85**	79
Comparable EBITDA	**522**	544	**1,561**	1,575
Depreciation and amortization	**(255)**	(228)	**(761)**	(672)
Comparable EBIT and segmented earnings	**267**	316	**800**	903

1 Includes results from Foothills, Ventures LP, Great Lakes Canada, and our share of equity income from our investment in TQM as well as general and administrative and business development costs related to our Canadian Natural Gas Pipelines.

Canadian Natural Gas Pipelines segmented earnings decreased by $49 million and $103 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017 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 AND AVERAGE INVESTMENT BASE

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Net Income				
NGTL System	**101**	92	**289**	261
Canadian Mainline	**40**	49	**121**	149
Average investment base				
NGTL System			**9,419**	8,210
Canadian Mainline			**3,855**	4,165

Net income for the NGTL System increased by $9 million and $28 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017 mainly due to a higher average investment base resulting from continued system expansions, partially offset by lower OM&A incentive earnings. On June 19, 2018, the NEB approved NGTL's 2018-2019 Revenue Requirement Settlement Application (the 2018-2019 Settlement). This settlement, which is effective from January 1, 2018 to December 31, 2019, includes an ROE of 10.1 per cent on 40 per cent deemed equity, a mechanism for sharing variances above and below a fixed annual OM&A amount, flow-through treatment of all other costs and an increase in depreciation rates. See the Recent developments section for additional details.

Net income for the Canadian Mainline decreased by $9 million and $28 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017 primarily due to incentive earnings recorded in 2017. Incentive earnings have not been recognized in 2018 pending an NEB decision on the 2018-2020 Tolls Review. As a result of the pending decision, the Canadian Mainline earnings to date reflect the last approved ROE of 10.1 per cent on 40 per cent deemed equity.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $27 million and $89 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017 mainly due to NGTL System facilities that were placed in service and an increase in the approved depreciation rates in the 2018-2019 Settlement.

U.S. Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(unaudited - millions of US$, unless noted otherwise)	**2018**	**2017**	**2018**	**2017**
Columbia Gas	**204**	125	**637**	446
ANR	**111**	86	**370**	301
TC PipeLines, LP[1,2,3]	**30**	28	**102**	87
Great Lakes[4]	**18**	9	**74**	49
Midstream	**42**	27	**101**	70
Columbia Gulf	**34**	16	**90**	55
Other U.S. pipelines[3,5]	**19**	14	**50**	64
Non-controlling interests[6]	**89**	80	**304**	266
Comparable EBITDA	**547**	385	**1,728**	1,338
Depreciation and amortization	**(130)**	(116)	**(380)**	(340)
Comparable EBIT	**417**	269	**1,348**	998
Foreign exchange impact	**128**	68	**386**	311
Comparable EBIT (Cdn$)	**545**	337	**1,734**	1,309
Specific item:				
Integration and acquisition related costs – Columbia	**—**	—	**—**	(10)
Segmented earnings (Cdn$)	**545**	337	**1,734**	1,299

1 Results reflect our earnings from TC PipeLines, LP's ownership interests in GTN, Great Lakes, Iroquois, Northern Border, Bison, PNGTS, North Baja and Tuscarora, as well as general and administrative costs related to TC PipeLines, LP.

2 TC PipeLines, LP periodically conducts ATM equity issuances which decrease our ownership in TC PipeLines, LP. For the three months ended September 30, 2018, our ownership interest in TC PipeLines, LP was 25.5 per cent compared to 26.0 per cent for the same period in 2017. Our ownership interest for the nine months ended September 30, 2018, was 25.5 per cent compared to a range of 26.5 to 26.0 per cent for the same period in 2017.

3 TC PipeLines, LP acquired 49.34 per cent of our 50 per cent interest in Iroquois and our remaining 11.81 per cent interest in PNGTS on June 1, 2017.

4 Results reflect our 53.55 per cent direct interest in Great Lakes. The remaining 46.45 per cent is held by TC PipeLines, LP.

5 Results reflect earnings from our direct ownership interests in Crossroads, as well as Iroquois and PNGTS until June 1, 2017, and our effective ownership in Millennium and Hardy Storage, as well as general and administrative and business development costs related to our U.S. natural gas pipelines.

6 Results reflect earnings attributable to portions of TC PipeLines, LP, PNGTS (until June 1, 2017) and CPPL (until February 17, 2017) that we do not own.

U.S. Natural Gas Pipelines segmented earnings increased by $208 million and $435 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017.

Segmented earnings for the nine months ended September 30, 2017 included a $10 million pre-tax charge for integration and acquisition related costs associated with the Columbia acquisition. This amount has been excluded from our calculation of comparable EBIT. A weaker U.S. dollar in 2018 had a negative impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2017, although the U.S. dollar was stronger in third quarter 2018 compared to the same period in 2017.

Earnings from our U.S. Natural Gas Pipelines operations are generally affected by contracted volume levels, volumes delivered and the rates charged as well as by the cost of providing services. Columbia Gas and ANR results are also affected by the contracting and pricing of their storage capacity and commodity sales.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$162 million and US$390 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017. This was primarily the net effect of:

- increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes and improved commodity prices and throughput volumes in Midstream
- increased earnings due to the amortization of the net regulatory liabilities recognized in 2017, partially offset by a reduction in certain rates on Columbia Gas, as a result of U.S. Tax Reform
- a US$10 million refund from GTN to its recourse rate customers as per the 2018 GTN Settlement. Refer to the 2018 FERC Actions section for additional details.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US$14 million and US$40 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017 mainly due to new projects placed in service.

Mexico Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(unaudited - millions of US$, unless noted otherwise)	**2018**	**2017**	**2018**	**2017**
Topolobampo	**42**	39	**128**	119
Tamazunchale	**33**	29	**96**	85
Mazatlán	**19**	16	**58**	49
Guadalajara	**18**	17	**53**	51
Sur de Texas[1]	**4**	3	**14**	14
Other	**—**	(10)	**4**	(10)
Comparable EBITDA	**116**	94	**353**	308
Depreciation and amortization	**(19)**	(18)	**(56)**	(54)
Comparable EBIT	**97**	76	**297**	254
Foreign exchange impact	**30**	19	**85**	79
Comparable EBIT and segmented earnings (Cdn$)	**127**	95	**382**	333

1 Represents equity income from our 60 per cent interest.

Mexico Natural Gas Pipelines segmented earnings increased by $32 million and $49 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017 and are equivalent to comparable EBIT. Earnings from our Mexico operations are underpinned by long-term, stable, primarily U.S. dollar-denominated revenue contracts, and are affected by the cost of providing service. A weaker U.S. dollar in the first nine months of 2018 had a negative impact on Canadian dollar equivalent segmented earnings from our Mexico operations compared to the same period in 2017, although the U.S. dollar was stronger in third quarter 2018 compared to the same period in 2017.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$22 million and US$45 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017 as a result of:

- higher revenues from operations as a result of changes in timing of revenue recognition
- the impairment of our equity investment in TransGas in third quarter 2017.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization remained largely consistent for the three and nine months ended September 30, 2018 compared to the same periods in 2017.

Liquids Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Keystone Pipeline System	**350**	302	**1,042**	937
Intra-Alberta pipelines	**46**	4	**122**	4
Liquids marketing and other	**71**	(3)	**147**	6
Comparable EBITDA	**467**	303	**1,311**	947
Depreciation and amortization	**(86)**	(71)	**(254)**	(228)
Comparable EBIT	**381**	232	**1,057**	719
Specific items:				
Keystone XL asset costs	**—**	(10)	**—**	(23)
Risk management activities	**(65)**	(19)	**(10)**	(15)
Segmented earnings	**316**	203	**1,047**	681
Comparable EBIT denominated as follows:				
Canadian dollars	**96**	63	**278**	175
U.S. dollars	**218**	135	**605**	416
Foreign exchange impact	**67**	34	**174**	128
	381	232	**1,057**	719

Liquids Pipelines segmented earnings increased by $113 million and $366 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017 and included the following specific items:

- pre-tax charges related to the maintenance of Keystone XL assets which were expensed in 2017 pending further advancement of the project. In 2018, Keystone XL expenditures are being capitalized
- unrealized losses from changes in the fair value of derivatives related to our liquids marketing business.

Liquids Pipelines earnings are generated primarily by providing pipeline capacity to shippers for fixed monthly payments that are not linked to actual throughput volumes. The Keystone Pipeline System also offers uncontracted capacity to the market on a spot basis which provides opportunities to generate incremental earnings. Our liquids marketing business provides customers with a variety of crude oil marketing services including transportation, storage, and crude oil supply, primarily transacted through the purchase and sale of crude oil.

Comparable EBITDA for Liquids Pipelines increased by $164 million and $364 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017 and was the net effect of:

- contributions from intra-Alberta pipelines, Grand Rapids and Northern Courier, which began operations in the second half of 2017
- a higher contribution from liquids marketing activities
- higher contracted and uncontracted volumes on the Keystone Pipeline System
- foreign exchange impact on the Canadian dollar equivalent earnings from our U.S. operations.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $15 million and $26 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017 as a result of new facilities being placed in service.

Energy

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian $, unless noted otherwise)	2018	2017	2018	2017
Canadian Power				
Western Power	**37**	24	**108**	77
Eastern Power[1]	**69**	75	**221**	252
Bruce Power[1]	**100**	91	**245**	314
U.S. Power (US$)[2]	**—**	22	**—**	108
Foreign exchange impact on U.S. Power	**—**	7	**—**	34
Natural Gas Storage and other	**4**	8	**21**	40
Business Development	**(3)**	(3)	**(10)**	(9)
Comparable EBITDA	**207**	224	**585**	816
Depreciation and amortization	**(27)**	(39)	**(92)**	(118)
Comparable EBIT	**180**	185	**493**	698
Specific items:				
U.S. Northeast power marketing contracts	**12**	—	**5**	—
Net (loss)/gain on sales of U.S. Northeast power generation assets	**—**	(12)	**—**	469
Risk management activities	**31**	64	**(34)**	(87)
Segmented earnings	**223**	237	**464**	1,080

1 Includes our share of equity income from our investments in Portlands Energy and Bruce Power.
2 In second quarter 2017, we completed the sales of our U.S. Northeast power generation assets.

Energy segmented earnings decreased by $14 million and $616 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017 and included the following specific items:

- a gain of $12 million and $5 million for the three and nine months ended September 30, 2018 related to our U.S. Northeast power marketing contracts. The year-to-date amount includes a gain in first quarter 2018 on the sale of our retail contracts. These amounts have been excluded from Energy's comparable earnings effective January 1, 2018 as we do not consider the wind-down of the remaining contracts part of our underlying operations. The contract portfolio is scheduled to run-off through to mid-2020
- a net loss of $12 million and a net gain of $469 million before tax for the three and nine months ended September 30, 2017 related to the monetization of our U.S. Northeast power generation assets
- unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks, as noted in the table below.

Risk management activities	three months ended September 30		nine months ended September 30	
(unaudited - millions of $, pre-tax)	2018	2017	2018	2017
Canadian Power	**—**	1	**3**	5
U.S. Power	**31**	59	**(31)**	(97)
Natural Gas Storage and Other	**—**	4	**(6)**	5
Total unrealized gains/(losses) from risk management activities	**31**	64	**(34)**	(87)

Comparable EBITDA for Energy decreased by $17 million and $231 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017 primarily due to the net effect of:

- lower earnings from U.S. Power mainly due to the sales of the U.S. Northeast power generation assets in second quarter 2017
- decreased Bruce Power year-to-date earnings primarily due to lower volumes resulting from higher outage days and lower results from contracting activities. Additional financial and operating information on Bruce Power is provided below
- lower Eastern Power results due to the sale of our Ontario solar assets in December 2017
- increased Western Power results due to higher realized margins on higher generation volumes
- decreased Natural Gas Storage results primarily due to lower realized natural gas storage price spreads.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization decreased by $12 million and $26 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017 primarily due to the sale of our Ontario solar assets in December 2017 as well as the cessation of depreciation on our Cartier Wind power facilities upon classification as held for sale on June 30, 2018.

BRUCE POWER

The following reflects 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)	**2018**	**2017**	**2018**	**2017**
Equity income included in comparable EBITDA and EBIT comprised of:				
Revenues	**397**	383	**1,153**	1,212
Operating expenses	**(204)**	(205)	**(640)**	(638)
Depreciation and other	**(93)**	(87)	**(268)**	(260)
Comparable EBITDA and EBIT[1]	**100**	91	**245**	314
Bruce Power – other information				
Plant availability[2]	**89%**	86%	**88%**	89%
Planned outage days	**30**	81	**180**	178
Unplanned outage days	**43**	19	**77**	39
Sales volumes (GWh)[1]	**6,087**	5,801	**17,810**	18,093
Realized sales price per MWh[3]	**$67**	$67	**$67**	$67

1 Represents our 48.3 per cent (2017 – 48.4 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.

Planned outage work on Unit 1 and Unit 4 was completed in the first half of 2018. Planned maintenance on Unit 8 began in September 2018 and is scheduled to be completed in fourth quarter 2018. Planned maintenance is expected to begin on Unit 3 in fourth quarter 2018 and continue into early 2019. The overall average plant availability percentage in 2018 is expected to be in the high 80 per cent range.

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented losses (the most directly comparable GAAP measure).

(unaudited - millions of $)	three months ended September 30 2018	three months ended September 30 2017	nine months ended September 30 2018	nine months ended September 30 2017
Comparable EBITDA and EBIT	**(8)**	(4)	**(25)**	(20)
Specific items:				
Foreign exchange (loss)/gain – inter-affiliate loan[1]	**(60)**	7	**(52)**	(1)
Integration and acquisition related costs – Columbia	**—**	(32)	**—**	(81)
Segmented losses	**(68)**	(29)	**(77)**	(102)

1 Reported in Income from equity investments in our Corporate segment.

Corporate segmented losses increased by $39 million and decreased by $25 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017. These results included the following specific items that have been excluded from comparable EBIT:

- foreign exchange losses and gains on a peso-denominated inter-affiliate loan to the Sur de Texas project for our proportionate share of the affiliate's project financing. There are corresponding foreign exchange gains and losses included in Interest income and other on the inter-affiliate loan receivable which fully offset these amounts
- in 2017, integration-related costs associated with the acquisition of Columbia.

OTHER INCOME STATEMENT ITEMS

Interest expense

(unaudited - millions of $)	three months ended September 30 2018	three months ended September 30 2017	nine months ended September 30 2018	nine months ended September 30 2017
Interest on long-term debt and junior subordinated notes				
Canadian dollar-denominated	**(142)**	(130)	**(407)**	(356)
U.S. dollar-denominated	**(335)**	(314)	**(981)**	(954)
Foreign exchange impact	**(103)**	(79)	**(283)**	(293)
	(580)	(523)	**(1,671)**	(1,603)
Other interest and amortization expense	**(30)**	(29)	**(80)**	(74)
Capitalized interest	**33**	49	**89**	150
Interest expense included in comparable earnings	**(577)**	(503)	**(1,662)**	(1,527)
Specific Item:				
Risk management activities	**—**	(1)	**—**	(1)
Interest expense	**(577)**	(504)	**(1,662)**	(1,528)

Interest expense increased by $73 million and $134 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017 and primarily reflects the net effect of:

- long-term debt and junior subordinated notes issuances, net of maturities
- lower capitalized interest primarily due to the completion of Grand Rapids and Northern Courier in the second half of 2017, partially offset by ongoing construction at Napanee and the recommencement of capitalization of Keystone XL costs in 2018

- final repayment of the Columbia acquisition bridge facilities in June 2017 resulting in lower interest and debt amortization expense
- foreign exchange impact on translation of U.S. dollar-denominated interest.

Allowance for funds used during construction

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Canadian dollar-denominated	**27**	44	**68**	149
U.S. dollar-denominated	**91**	81	**230**	168
Foreign exchange impact	**29**	20	**67**	50
Allowance for funds used during construction	**147**	145	**365**	367

AFUDC increased by $2 million and decreased by $2 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017.

The decrease in Canadian dollar-denominated AFUDC is primarily due to the October 2017 decision not to proceed with the Energy East pipeline project and completion of various expansion programs in first quarter 2018.

The increase in U.S. dollar-denominated AFUDC is primarily due to additional investment in and higher AFUDC rates on Columbia Gas and Columbia Gulf growth projects and continued investment in Mexico projects, partially offset by the commercial in-service of Leach Xpress and Cameron Access in first quarter 2018.

Interest income and other

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Interest income and other included in comparable earnings	**48**	58	**166**	103
Specific items:				
Foreign exchange gain/(loss) – inter-affiliate loan	**60**	(7)	**52**	1
Risk management activities	**60**	33	**(79)**	89
Interest income and other	**168**	84	**139**	193

Interest income and other increased by $84 million for the three months ended September 30, 2018 compared to the same period in 2017 and was primarily the net effect of:

- higher interest income and a $60 million foreign exchange gain compared to a $7 million loss in 2017 related to an inter-affiliate loan receivable from the Sur de Texas joint venture. The corresponding interest expense and foreign exchange loss are reflected in Income from equity investments in the Mexico Natural Gas Pipelines and Corporate segments, respectively. The offsetting currency-related gain and loss amounts are excluded from comparable earnings
- higher unrealized gains on risk management activities in 2018 compared to 2017. These amounts have been excluded from comparable earnings
- realized losses in 2018 compared to realized gains in 2017 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- income of $10 million recognized in 2017 on termination of the PRGT project, related to the recovery of carrying costs.

Interest income and other decreased by $54 million for the nine months ended September 30, 2018 compared to the same period in 2017 and was primarily the net effect of:

- higher interest income and a $52 million foreign exchange gain related to an inter-affiliate loan receivable from the Sur de Texas joint venture. The corresponding interest expense and foreign exchange loss are reflected in Income from equity investments in the Mexico Natural Gas Pipelines and Corporate segments, respectively. The offsetting currency-related gain and loss amounts are excluded from comparable earnings
- unrealized losses on risk management activities in 2018 compared to unrealized gains in 2017. These amounts have been excluded from comparable earnings
- income of $20 million related to reimbursement of Coastal GasLink (CGL) project costs in 2017
- income of $10 million recognized in 2017, on termination of the PRGT project, related to the recovery of carrying costs.

Income tax expense

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Income tax expense included in comparable earnings	**(108)**	(163)	**(425)**	(605)
Specific items:				
U.S. Northeast power marketing contracts	**(4)**	—	**(2)**	—
Integration and acquisition related costs – Columbia	**—**	2	**—**	22
Keystone XL asset costs	**—**	2	**—**	4
Net gain on sales of U.S. Northeast power generation assets	**—**	—	**—**	(226)
Keystone XL income tax recoveries	**—**	—	**—**	7
Risk management activities	**(8)**	(29)	**33**	17
Income tax expense	**(120)**	(188)	**(394)**	(781)

Income tax expense included in comparable earnings decreased by $55 million and $180 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017. This was primarily due to lower income tax rates as a result of U.S. Tax Reform and lower flow-through income taxes in Canadian rate-regulated pipelines, partially offset by higher comparable earnings before income taxes.

Net income attributable to non-controlling interests

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Net income attributable to non-controlling interests	**(59)**	(44)	**(229)**	(189)

Net income attributable to non-controlling interests increased by $15 million and $40 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017 primarily due to higher earnings in TC PipeLines, LP. Higher net income attributable to non-controlling interests for the nine months ended September 30, 2018 was partially offset by our acquisition of the remaining outstanding publicly held common units of CPPL in February 2017.

Preferred share dividends

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Preferred share dividends	**(41)**	(40)	**(122)**	(120)

Preferred share dividends remained largely consistent for the three and nine months ended September 30, 2018 compared to the same periods in 2017.

Recent developments

CANADIAN NATURAL GAS PIPELINES

Coastal GasLink Pipeline Project

On October 2, 2018, we announced that we will proceed with construction of the CGL pipeline project following the LNG Canada joint venture participants' announcement that they have reached a positive FID to build the LNG Canada natural gas liquefaction facility in Kitimat, B.C. CGL will provide the natural gas supply to the LNG Canada facility and is underpinned by 25-year TSAs (with additional renewal provisions) with the LNG Canada participants. CGL is a 670 km (420 miles) pipeline with an initial capacity of approximately 2.2 PJ/d (2.1 Bcf/d) with potential expansion capacity up to 5.4PJ/d (5.0 Bcf/d). All necessary regulatory permits have been received to allow us to proceed with construction activities which are expected to begin in January 2019, with a planned in-service date in 2023. CGL has signed project and community agreements with all 20 elected Indigenous bands along the pipeline route, confirming strong support from Indigenous communities across the province of B.C.

On July 30, 2018, an individual asked the NEB to consider whether the CGL pipeline should be federally regulated by the NEB. On October 22, 2018, the NEB advised that it would consider the question of jurisdiction. In the same letter, the NEB set a process to determine whether the individual who raised the question has standing, and to decide on the standing of any other interested parties. The process to consider the jurisdiction question is to be determined and the permits to construct remain valid.

The capital cost estimate is $6.2 billion with the majority of the construction spend occurring in 2020 and 2021. Subject to terms and conditions, differences between the estimated capital cost and final cost of the project will be recovered in future pipeline tolls. As part of the CGL funding plan, we intend to explore joint venture partners and project financing for the project.

The total capital cost includes pre-development costs to date of approximately $470 million. In accordance with provisions in the agreements with the LNG Canada joint venture participants, to date, four parties have elected to reimburse us for their share of pre-development costs, totaling $399 million of cost reimbursement, with payments due by November 30, 2018.

NGTL System

2022 NGTL System Expansion Program

On October 31, 2018, we announced the NGTL 2022 Expansion Program to meet capacity requirements for incremental firm receipt and intra-basin delivery services to commence in November 2021 and April 2022. This $1.5 billion expansion of the NGTL System consists of approximately 197 km (122 miles) of new pipeline, three compressor units, meter stations and associated facilities. Applications for approvals to construct and operate the facilities are expected to be filed with the NEB in second quarter 2019 and, pending receipt of regulatory approvals, construction would start as early as third quarter 2020.

2021 NGTL System Expansion Program Application

On June 20, 2018, we filed an application with the NEB for approval to construct and operate the 2021 Expansion Program. The program, with an estimated capital cost of $2.3 billion, consists of approximately 344 km (214 miles) of new pipeline, three compressors and a control valve. The expansion is required to accept increasing supply from the west side of the system and deliver gas to increasing market demand on the east side of the system. The anticipated in-service date for the expansion is the first half of 2021.

North Montney Project Approval

In July 2018, the NEB issued an amending order, following Federal government approval of our application, to the existing North Montney project approvals to remove the condition requiring a positive FID for the Pacific Northwest LNG project prior to commencement of construction.

The North Montney project consists of approximately 206 km (128 miles) of new pipeline, three compressor units and 14 meter stations. The current estimated project cost has increased by $0.2 billion to $1.6 billion mainly due to construction schedule delays and an increase in market-dependent construction costs.

The NEB directed NGTL to seek approval for a revised tolling methodology for the project following a provisional period defined as one year after the receipt of the Federal government decision, or otherwise impose stand-alone tolling as a default. NGTL is working with its shippers to address this requirement and is confident an appropriate tolling mechanism can be achieved.

The first phase of the project is anticipated to be in service by fourth quarter 2019 and the second phase by second quarter 2020.

Other Projects

Our 2019 capital program has increased by approximately $0.2 billion primarily due to higher construction costs related to the Saddle West project.

On April 9, 2018, we announced that the Sundre Crossover project was placed in service. The $100 million pipeline project increases NGTL System capacity at our Alberta / B.C. export delivery point by approximately 245 TJ/d (228 MMcf/d), enhancing connectivity to key downstream markets in the Pacific Northwest and California.

On April 2, 2018, we announced that the Northwest Mainline Loop-Boundary Lake project was placed in service. The $160 million project added approximately 230 km (143 miles) of new pipeline along with compression facilities and increased the NGTL System capacity by approximately 535 TJ/d (500 MMcf/d).

On March 20, 2018, we announced the successful completion of an open season for additional expansion capacity at the Empress / McNeill Export Delivery Point for service expected to commence in November 2021. The offering of 300 TJ/d (280 MMcf/d) was oversubscribed, with an average awarded contract term of approximately 22 years. The facilities and capital requirements for the expansion are estimated to be approximately $0.1 billion.

NGTL 2018-2019 Revenue Requirement Settlement Approval

On June 19, 2018, the NEB approved the 2018-2019 Settlement, as filed, for final 2018 tolls. The 2018-2019 Settlement fixes ROE at 10.1 per cent on 40 per cent deemed equity and increases the composite depreciation rate from 3.18 per cent to 3.45 per cent. OM&A costs are fixed at $225 million for 2018 and $230 million for 2019 with a 50/50 sharing mechanism for any variances between the fixed amounts and actual OM&A costs. All other costs, including pipeline integrity expenses and emissions costs, are treated as flow-through expenses.

Canadian Mainline

Canadian Mainline 2018-2020 Toll Review

On October 9, 2018, we concluded the written hearing process for the Canadian Mainline 2018-2020 toll review with the filing of our reply evidence to the NEB. We have requested a decision by December 31, 2018.

Maple Compressor Expansion Project

On April 27, 2018, we received NEB approval to proceed with construction of this approximate $110 million compressor unit addition project. Work continues as planned to meet a November 1, 2019 in-service date.

U.S. NATURAL GAS PIPELINES

Nixon Ridge

On June 7, 2018, a natural gas pipeline rupture on Columbia Gas occurred on Nixon Ridge in Marshall County, West Virginia. Emergency response procedures were enacted and the segment of impacted pipeline was isolated shortly thereafter. There were no injuries involved with this incident and no material damage to surrounding structures. The pipeline was placed back in service on July 15, 2018. The preliminary investigation, as noted in the PHMSA Proposed Safety Order, suggests that the rupture was a result of land subsidence. The investigation remains ongoing and we are fully cooperating with PHMSA to determine the root cause of the incident. We do not expect this event to have a significant impact on our financial results.

Cameron Access

The Cameron Access project, a Columbia Gulf project designed to transport approximately 0.9 PJ/d (0.8 Bcf/d) of gas supply to the Cameron LNG export terminal in Louisiana, was placed in service on March 13, 2018.

WB XPress and Mountaineer XPress

The Western Build of the WB Xpress (WBX) project was placed into service on October 5, 2018. The Eastern Build of WBX remains to be completed, as planned, in fourth quarter 2018. In first quarter 2018, estimated project costs were revised upwards to US$0.9 billion for WBX and US$3.0 billion for MXP. These increases, primarily in MXP, reflect the impact of delays of various regulatory approvals from FERC and other agencies, increased contractor construction costs due to unusually high demand for construction resources in the region, and modifications to contractor work plans to mitigate construction delays associated with these impacts. Unusually high instances of inclement weather throughout construction has placed continued cost and schedule pressures on these projects.

U.S. Pipelines Rate Settlements

In February 2018, FERC approved the 2017 Great Lakes Rate Settlement and the 2017 Northern Border Rate Settlement, both of which were uncontested. The rates established under both of these settlements are subject to change upon the final outcome of the filings in response to the 2018 FERC Actions.

In October 2018, GTN filed with FERC an uncontested settlement with its customers. Refer to the 2018 FERC Actions for additional detail.

MEXICO NATURAL GAS PIPELINES

Topolobampo

On June 29, 2018, the Topolobampo pipeline was placed in service. The 560 km (348 miles) pipeline provides capacity of 720 TJ/d (670 MMcf/d), receiving natural gas from upstream pipelines near El Encino, in the state of Chihuahua, and delivering to points along the pipeline route including our Mazatlán pipeline at El Oro, in the state of Sinaloa. Under the force majeure terms of the TSA, we began collecting and recognizing revenue from the original TSA service commencement date of July 2016.

Sur de Texas

Offshore construction was completed in May 2018 and the project continues to progress toward an anticipated in-service date at the end of 2018. An amending agreement has been signed with the CFE that recognizes force majeure events and the commencement of payments of fixed capacity charges beginning October 31, 2018.

Tula and Villa de Reyes

The CFE has approved the recognition of force majeure events for both of these pipelines, including the continuation of the payment of fixed capacity charges to us that began in first quarter 2018. Construction for the Villa de Reyes project is ongoing and is anticipated to be in service by the second half of 2019.

LIQUIDS PIPELINES

Keystone XL

In December 2017, an appeal to Nebraska's Court of Appeals was filed by intervenors after the Nebraska PSC issued an approval of an alternative route for the Keystone XL project in November 2017. In March 2018, the Nebraska Supreme Court, on its own motion, agreed to bypass the Court of Appeals and directly hear the appeal case against the PSC's alternative route. Legal briefs on the appeal were submitted in May 2018 and oral argument before the Nebraska Supreme Court has been set for November 1, 2018. We expect the Nebraska Supreme Court, as the final arbiter, could reach a decision by first quarter 2019.

The Keystone XL Presidential Permit, issued in March 2017, has been challenged in two separate lawsuits commenced in Montana. Together with the U.S. Department of Justice (DOJ), we are actively participating in these lawsuits to defend both the issuance of the permit and the exhaustive environmental assessments that support the U.S. President's actions. Legal arguments addressing the merits of these lawsuits were heard in May 2018 and we believe the court's decisions on certain elements of these legal challenges may be issued by the end of 2018.

In May 2018, the U.S. Department of State (DOS) filed a notice of its intent to prepare an environmental assessment for the Keystone XL mainline alternative route in Nebraska. Public comments were received in June 2018 and in July 2018 the DOS issued a draft environmental assessment. However, on August 15, 2018, the U.S. District Court in Montana issued a Partial Order requiring the DOJ and the DOS (the Federal Defendants) to prepare a supplemental environmental impact statement (SEIS) to the 2014 Final Supplemental Environmental Impact Statement and a proposed schedule for the completion of the SEIS. On September 4, 2018, the Federal Defendants responded to this Partial Order by filing the required schedule which reflected the issuance of the final SEIS in December 2018. On September 21, 2018, the DOS issued a draft SEIS which concluded that implementation of the mainline alternative route would have no significant direct, indirect or cumulative effect on the quality of the natural or human environments, having consideration for the mitigation plans proposed by TransCanada. The draft SEIS is open for public comment for a period of 45 days. The Federal Defendants also indicated that the U.S. Bureau of Land Management and the U.S. Army Corps of Engineers would likely issue decisions regarding their respective federal permitting activities in first quarter 2019.

In September 2018, two U.S. Native American communities filed a lawsuit in Montana challenging the Keystone XL Presidential Permit. It is uncertain how and when this lawsuit will proceed.

The South Dakota Public Utilities Commission permit for the Keystone XL project was issued in June 2010 and recertified in January 2016. An appeal of that recertification was denied in June 2017 and that decision was further appealed to the South Dakota Supreme Court. On June 13, 2018, the Supreme Court dismissed the appeal against the recertification of the Keystone XL project finding that the lower court lacked jurisdiction to hear the case. This decision is final as there can be no further appeals from this decision by the Supreme Court.

White Spruce

In February 2018, the AER issued a permit for the construction of the White Spruce pipeline. Construction has commenced with an anticipated in-service date in second quarter 2019.

ENERGY

Cartier Wind

On October 24, 2018, we completed the sale of our interests in the Cartier Wind power facilities in Québec to Innergex Renewable Energy Inc. for gross proceeds of approximately $630 million before closing adjustments resulting in an estimated gain of $170 million ($135 million after tax) to be recorded in fourth quarter 2018.

Bruce Power - Life Extension

On September 28, 2018, Bruce Power submitted its final cost and schedule duration estimate (basis of estimate) for the Unit 6 Major Component Replacement (MCR) program to the IESO. The IESO has up to three months to review and verify the basis of estimate. As the cost and schedule duration are both less than the thresholds defined in the program's life extension and refurbishment agreement, no further approvals from the IESO or the government are required to proceed with the Unit 6 MCR outage in early 2020. The Unit 6 MCR outage is expected to be completed in late 2023.

As a result of this filing, we have updated our project cost estimates in our Capital Program tables to reflect our expected investment of approximately $2.2 billion (in nominal dollars) in Bruce Power's Unit 6 MCR program and ongoing Asset Management (AM) program through 2023, and approximately $6.0 billion (in 2018 dollars) for the remaining five-unit MCR program and the AM program beyond 2023. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available for Bruce Power and the IESO.

Bruce Power's current contract price of approximately $68 per MWh will be increased in April 2019 to reflect capital to be invested under the Unit 6 MCR program and the AM program as well as normal annual inflation adjustments.

Napanee

Construction continues on our 900 MW natural gas-fired power plant at OPG's Lennox site in eastern Ontario in the town of Greater Napanee. We expect our total investment in the Napanee facility will be approximately $1.6 billion and commercial operations are expected to begin in first quarter 2019. Costs have increased due to delays in the construction schedule. Once in service, production from the facility is fully contracted with the IESO for a 20-year period.

Monetization of U.S. Northeast power marketing business

On March 1, 2018, as part of the continued wind-down of our U.S. Northeast power marketing contracts, we closed the sale of our U.S. power retail contracts for proceeds of approximately US$23 million and recognized income of US$10 million (US$7 million after tax).

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 Corporate ATM program and our DRP, portfolio management, cash on hand and substantial committed credit facilities. Annually, in fourth quarter, we extend and renew our credit facilities as required. In light of the 2018 FERC Actions initially proposed in March 2018, further drop downs of assets into TC PipeLines, LP were considered to no longer be a viable funding lever. In addition, the TC PipeLines, LP ATM program ceased to be utilized. Pursuant to the 2018 FERC Actions on July 18, 2018, it is yet to be determined if and when in the future these might be restored as competitive financing options. See the 2018 FERC Actions section for further information.

At September 30, 2018, our current assets totaled $5.1 billion and current liabilities amounted to $11.0 billion, leaving us with a working capital deficit of $5.9 billion compared to $5.2 billion at December 31, 2017. Our working capital deficit 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 $9.5 billion of unutilized, unsecured credit facilities.

CASH PROVIDED BY OPERATING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $, except per share amounts)	**2018**	**2017**	**2018**	**2017**
Net cash provided by operations	**1,299**	1,185	**4,516**	3,840
Increase in operating working capital	**284**	86	**130**	224
Funds generated from operations[1]	**1,583**	1,271	**4,646**	4,064
Specific items:				
U.S. Northeast power marketing contracts	**(12)**	—	**(5)**	—
Integration and acquisition related costs – Columbia	**—**	32	**—**	84
Keystone XL asset costs	**—**	10	**—**	23
Net loss on sales of U.S. Northeast power generation assets	**—**	3	**—**	20
Comparable funds generated from operations[1]	**1,571**	1,316	**4,641**	4,191
Dividends on preferred shares	**(40)**	(39)	**(118)**	(116)
Distributions paid to non-controlling interests	**(57)**	(66)	**(174)**	(215)
Non-recoverable maintenance capital expenditures[2]	**(61)**	(41)	**(191)**	(169)
Comparable distributable cash flow[1]	**1,413**	1,170	**4,158**	3,691
Comparable distributable cash flow per common share[1]	**$1.56**	$1.34	**$4.63**	$4.24

1 See the Non-GAAP measures section of 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.

2 Includes non-recoverable maintenance capital expenditures from all segments including cash contributions to fund our proportionate share of maintenance capital expenditures for our equity investments which are primarily related to contributions to Bruce Power.

COMPARABLE FUNDS GENERATED FROM OPERATIONS

Comparable funds generated from operations, a non-GAAP measure, helps us assess the cash generating ability of our operations by excluding the timing effects of working capital changes.

Despite the sales of our U.S. Northeast power generation assets in second quarter 2017 and the continued wind-down of our U.S. Northeast power marketing contracts, comparable funds generated from operations increased by $255 million and $450 million for the three and nine months ended September 30, 2018 compared to the same periods in 2017. These increases are primarily due to higher comparable earnings.

COMPARABLE DISTRIBUTABLE CASH FLOW

Comparable distributable cash flow, a non-GAAP measure, helps us assess the cash available to common shareholders before capital allocation.

The increase in comparable distributable cash flow for the three and nine months ended September 30, 2018 compared to the same periods in 2017 reflects higher comparable funds generated from operations, as described above. Comparable distributable cash flow per common share for the three and nine months ended September 30, 2018 also reflects the dilutive impact of common shares issued under the Corporate ATM program and DRP in 2017 and 2018.

Beginning in 2018, our determination of comparable distributable cash flow has been revised to exclude the deduction of maintenance capital expenditures for assets for which we have the ability to recover these costs in pipeline tolls. Comparative periods presented in the table below have been adjusted accordingly. We believe that including only non-recoverable maintenance capital expenditures in the calculation of distributable cash flow presents the best depiction of the cash available for reinvestment or distribution to shareholders. For our rate-regulated Canadian and U.S. natural gas pipelines, we have the opportunity to recover and earn a return on maintenance capital expenditures through current and future tolls. Tolling arrangements in our liquids pipelines provide for the recovery of maintenance capital expenditures. Therefore, we have not deducted the recoverable maintenance capital expenditures for these businesses in the calculation of comparable distributable cash flow.

CASH USED IN INVESTING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Capital spending				
Capital expenditures	**(2,435)**	(2,031)	**(6,474)**	(5,383)
Capital projects in development	**(127)**	(37)	**(239)**	(135)
Contributions to equity investments	**(236)**	(475)	**(778)**	(1,140)
	(2,798)	(2,543)	**(7,491)**	(6,658)
Proceeds from sales of assets, net of transaction costs	**—**	—	**—**	4,147
Other distributions from equity investments	**—**	—	**121**	362
Deferred amounts and other	**(16)**	165	**78**	(87)
Net cash used in investing activities	**(2,814)**	(2,378)	**(7,292)**	(2,236)

Capital expenditures in 2018 were incurred primarily for the expansion of the Columbia Gas, Columbia Gulf and NGTL System natural gas pipelines along with the construction of the Napanee power generating facility and Mexico natural gas pipelines.

Costs incurred on capital projects in development in 2018 were predominantly related to spending on Keystone XL.

Contributions to equity investments in 2018 principally involve contributions to Bruce Power and Millennium as well as Sur de Texas which includes our proportionate share of debt financing requirements.

Other distributions from equity investments in 2018 primarily reflect our proportionate share of Bruce Power financings undertaken to fund its capital program and to make distributions to its partners. In first quarter 2018, Bruce Power issued senior notes in capital markets which resulted in distributions totaling $121 million to us.

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

CASH PROVIDED BY/(USED IN) FINANCING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Notes payable issued, net	**1,421**	451	**1,906**	1,232
Long-term debt issued, net of issue costs[1]	**1,026**	1,151	**4,359**	1,968
Long-term debt repaid[1]	**(1,232)**	(46)	**(3,266)**	(5,515)
Junior subordinated notes issued, net of issue costs	**—**	(3)	**—**	3,468
Dividends and distributions paid	**(513)**	(459)	**(1,446)**	(1,313)
Common shares issued, net of issue costs	**354**	6	**1,139**	42
Partnership units of TC PipeLines, LP issued, net of issue costs	**—**	43	**49**	162
Common units of Columbia Pipeline Partners LP acquired	**—**	—	**—**	(1,205)
Net cash provided by/(used in) financing activities	**1,056**	1,143	**2,741**	(1,161)

1 Includes draws and repayments on unsecured loan facility by TC PipeLines, LP.

LONG-TERM DEBT ISSUED

The following table outlines significant debt issuances in 2018:

(unaudited - millions of Canadian $, unless noted otherwise) Company	Issue date	Type	Maturity Date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	October 2018	Senior Unsecured Notes	March 2049	US 1,000	5.10%
	October 2018	Senior Unsecured Notes	May 2028	US 400	4.25%
	July 2018	Medium Term Notes	July 2048	800	4.18%
	July 2018	Medium Term Notes	March 2028	200	3.39%
	May 2018	Senior Unsecured Notes	May 2028	US 1,000	4.25%
	May 2018	Senior Unsecured Notes	May 2038	US 500	4.75%
	May 2018	Senior Unsecured Notes	May 2048	US 1,000	4.875%

The net proceeds of the above debt issuances were used for general corporate purposes, to fund our capital program and to prefund 2019 senior note maturities.

LONG-TERM DEBT REPAID

The following table outlines significant debt repaid in 2018:

(unaudited - millions of Canadian $, unless noted otherwise) Company	Retirement date	Type	Amount	Interest rate
COLUMBIA PIPELINE GROUP, INC.				
	June 2018	Senior Unsecured Notes	US 500	2.45%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM				
	May 2018	Senior Secured Notes	US 18	5.90%
TRANSCANADA PIPELINES LIMITED				
	August 2018	Senior Unsecured Notes	US 850	6.50%
	March 2018	Debentures	150	9.45%
	January 2018	Senior Unsecured Notes	US 500	1.875%
	January 2018	Senior Unsecured Notes	US 250	Floating
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP				
	March 2018	Senior Unsecured Notes	US 9	6.73%

DIVIDEND REINVESTMENT PLAN

With respect to dividends declared on August 1, 2018, the DRP participation rate amongst common shareholders was approximately 34 per cent, resulting in $213 million reinvested in common equity under the program. Year-to-date in 2018, the participation rate amongst common shareholders has been approximately 35 per cent, resulting in $655 million of dividends reinvested.

TRANSCANADA CORPORATION ATM EQUITY PROGRAM

In the three months ended September 30, 2018, 6.1 million common shares were issued under our Corporate ATM program at an average price of $57.75 per common share for proceeds of $351 million, net of related commissions and fees of approximately $3 million. In the nine months ended September 30, 2018, 20.0 million common shares have been issued under our Corporate ATM program at an average price of $56.13 per common share for proceeds of $1.1 billion, net of approximately $10 million of related commissions and fees.

In June 2018, we announced that the Company replenished the capacity available under our existing Corporate ATM program. This will allow us to issue additional common shares from treasury having an aggregate gross sales price of up to $1.0 billion, for a revised total of $2.0 billion or its U.S. dollar equivalent, to the public from time to time at the prevailing market price when sold through the TSX, the NYSE or on any other existing trading market for the common shares in Canada or the United States. The Corporate ATM program, as amended, is effective to July 23, 2019, and may be utilized at our discretion if and as required based on the spend profile of our capital program and relative cost of other funding options.

TC PIPELINES, LP ATM EQUITY ISSUANCE PROGRAM

In the nine months ended September 30, 2018, 0.7 million common units were issued under the TC PipeLines, LP ATM program generating net proceeds of approximately US$39 million. At September 30, 2018, our ownership interest in TC PipeLines, LP was 25.5 per cent giving effect to issuances under the ATM program resulting in dilution of our ownership interest.

As a result of the 2018 FERC Actions initially proposed in March 2018, the TC PipeLines, LP ATM program ceased to be utilized. As a result of uncertainties that remain after the 2018 FERC Actions were finalized in July 2018, it is yet to be determined if and when in the future the program might be reactivated.

DIVIDENDS

On October 31, 2018, we declared quarterly dividends as follows:

Quarterly dividend on our common shares
$0.69 per share
Payable on January 31, 2019 to shareholders of record at the close of business on December 31, 2018.

Quarterly dividends on our preferred shares	
Series 1	$0.204125
Series 2	$0.22077123
Series 3	$0.1345
Series 4	$0.17956575
Payable on December 31, 2018 to shareholders of record at the close of business on November 30, 2018.	
Series 5	$0.1414375
Series 6	$0.19446027
Series 7	$0.25
Series 9	$0.265625
Payable on January 30, 2019 to shareholders of record at the close of business on December 31, 2018.	
Series 11	$0.2375
Series 13	$0.34375
Series 15	$0.30625
Payable on November 30, 2018 to shareholders of record at the close of business on November 15, 2018.	

SHARE INFORMATION

as at October 29, 2018		
Common shares	**Issued and outstanding**	
	914 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**
	13 million	8 million

CREDIT FACILITIES

We have several committed credit facilities that support our commercial paper programs and provide short-term liquidity for general corporate purposes. 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 October 29, 2018, we had a total of $11.3 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 2022
US$2.0 billion	US$2.0 billion	TCPL	Supports TCPL's U.S. dollar commercial paper program and for general corporate purposes	December 2018
US$1.0 billion	US$1.0 billion	TCPL USA	Used for TCPL USA general corporate purposes, guaranteed by TCPL	December 2018
US$1.0 billion	US$0.2 billion	Columbia	Used for Columbia general corporate purposes, guaranteed by TCPL	December 2018
US$0.5 billion	US$0.5 billion	TAIL	Supports TAIL's U.S. dollar commercial paper program and for general corporate purposes, guaranteed by TCPL	December 2018
Demand senior unsecured revolving credit facilities				
$2.1 billion	$0.9 billion	TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity, TCPL USA facility guaranteed by TCPL	Demand
MXN$5.0 billion	MXN$4.5 billion	Mexican subsidiary	Used for Mexico general corporate purposes, guaranteed by TCPL	Demand

At October 29, 2018, our operated affiliates had an additional $0.7 billion of undrawn capacity on committed credit facilities.

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

CONTRACTUAL OBLIGATIONS

Our capital expenditure commitments have risen by approximately $4.5 billion since December 31, 2017. This increase is primarily due to commitments related to the construction of the CGL pipeline, Columbia Gas growth projects, NGTL System, Keystone XL and our proportionate share of commitments for Bruce Power's life extension program. This increase is partially offset by decreased commitments for the Sur de Texas natural gas pipeline and the Napanee power generating facility.

There were no other material changes to our contractual obligations in third quarter 2018 or to payments due in the next five years or after. See the MD&A in our 2017 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 2017 Annual Report for more information about the risks we face in our business. Our risks have not changed substantially since December 31, 2017, other than as described below.

On March 1, 2018, as part of the continued wind-down of our U.S. Northeast power marketing contracts, we closed the sale of our U.S. Northeast power retail contracts for proceeds of approximately US$23 million and recognized income of US$10 million (US$7 million after tax). 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:

- cash and cash equivalents
- accounts receivable
- available-for-sale assets
- the fair value of derivative assets
- loans receivable.

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At September 30, 2018, 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 our interest in the joint venture as an equity investment.

In 2017, we entered into a MXN$21.3 billion unsecured revolving credit facility with the joint venture, which bears interest at a floating rate and matures in March 2022. Draws on the credit facility result in a loan receivable from the joint venture representing our proportionate share of the debt financing requirements advanced to the joint venture. At September 30, 2018, the balance of our loan receivable from the joint venture totaled MXN$18.0 billion or $1.2 billion (December 31, 2017 – MXN$14.4 billion or $919 million) and Interest income and other included $32 million and $88 million of interest income on this loan receivable for the three and nine months ended September 30, 2018 (2017 – $11 million and $14 million). Amounts recognized in Interest income and other are offset by a corresponding proportionate share of interest expense recorded in Income from equity investments in our Mexico Natural Gas Pipelines segment.

INTEREST RATE RISK

We utilize short-term and long-term debt to finance our operations which subjects us to interest rate risk. We typically pay fixed rates of interest on our long-term debt and floating rates on our commercial paper programs and amounts drawn on our credit facilities. A small portion of our long-term debt is at floating interest rates. In addition, we are exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. We mitigate our interest rate risk using a combination of interest rate swaps and option derivatives.

FOREIGN EXCHANGE

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.

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, 2018	**1.31**
three months ended September 30, 2017	1.25

nine months ended September 30, 2018	**1.29**
nine months ended September 30, 2017	1.31

The impact of changes in the value of the U.S. dollar on our U.S. operations is partially 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 $)	**2018**	**2017**	**2018**	**2017**
U.S. Natural Gas Pipelines comparable EBIT	**417**	269	**1,348**	998
Mexico Natural Gas Pipelines comparable EBIT[1]	**122**	76	**366**	254
U.S. Liquids Pipelines comparable EBIT	**218**	135	**605**	416
U.S. Power comparable EBIT[2]	**—**	22	**—**	108
AFUDC on U.S. dollar-denominated projects	**91**	81	**230**	168
Interest on U.S. dollar-denominated long-term debt	**(335)**	(314)	**(981)**	(954)
Capitalized interest on U.S. dollar-denominated capital expenditures	**4**	1	**10**	2
U.S. dollar non-controlling interests and other	**(50)**	(39)	**(195)**	(146)
	467	231	**1,383**	846

1 Excludes interest expense on our inter-affiliate loan with Sur de Texas which is offset in Interest income and other.
2 Effective January 1, 2018, U.S. Power is no longer included in comparable EBIT.

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 amounts for the derivatives designated as a net investment hedge were as follows:

	September 30, 2018		December 31, 2017	
(unaudited - millions of Canadian $, unless noted otherwise)	**Fair value[1,2]**	**Notional amount**	**Fair value[1,2]**	**Notional amount**
U.S. dollar cross-currency interest rate swaps (maturing 2018 to 2019)[3]	**(42)**	**US 300**	(199)	US 1,200
U.S. dollar foreign exchange options (maturing 2018 to 2019)	**(2)**	**US 2,000**	5	US 500
	(44)	**US 2,300**	(194)	US 1,700

1 Fair values equal carrying values.
2 No amounts have been excluded from the assessment of hedge effectiveness.
3 In the three and nine months ended September 30, 2018, Net income includes net realized gains of nil and $1 million, respectively (2017 – $1 million and $3 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, 2018	December 31, 2017
Notional amount	**28,300 (US 21,900)**	25,400 (US 20,200)
Fair value	**30,200 (US 23,300)**	28,900 (US 23,100)

FINANCIAL INSTRUMENTS

With the exception of Long-term debt and Junior subordinated notes, our derivative and non-derivative financial 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, 2018	December 31, 2017
Other current assets	**372**	332
Intangible and other assets	**83**	73
Accounts payable and other	**(418)**	(387)
Other long-term liabilities	**(43)**	(72)
	(6)	(54)

Unrealized and realized (losses)/gains of derivative instruments

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

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	2018	2017	2018	2017
Derivative instruments held for trading[1]				
Amount of unrealized (losses)/gains in the period				
Commodities[2]	**(31)**	45	**(41)**	(102)
Foreign exchange	**60**	33	**(79)**	89
Interest rate	**—**	(1)	**—**	(1)
Amount of realized gains/(losses) in the period				
Commodities	**81**	(82)	**210**	(167)
Foreign exchange	**(5)**	19	**14**	10
Interest rate	**—**	1	**—**	1
Derivative instruments in hedging relationships				
Amount of realized gains/(losses) in the period				
Commodities	**1**	4	**—**	17
Foreign exchange	**—**	—	**—**	5
Interest rate	**(2)**	—	**(1)**	1

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

2 In the three and nine months ended September 30, 2018 and 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.

Derivatives in cash flow hedging relationships

The components of the Condensed consolidated statement of comprehensive income 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 $)	2018	2017	2018	2017
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]				
Commodities	**3**	2	**(3)**	5
Interest rate	**2**	(1)	**11**	—
	5	1	**8**	5
Reclassification of gains/(losses) on derivative instruments from AOCI to net income[1]				
Commodities[2]	**3**	(4)	**4**	(15)
Interest rate[3]	**5**	4	**17**	13
	8	—	**21**	(2)

1 Amounts presented are pre-tax. 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 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, 2018, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $2 million (December 31, 2017 – $2 million), with no collateral provided in the normal course of business at September 30, 2018 and December 31, 2017. If the credit-risk-related contingent features in these agreements were triggered on September 30, 2018, we would have been required to provide collateral of $2 million (December 31, 2017 – $2 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, 2018, as required by the Canadian securities regulatory authorities and by the SEC, and concluded that our disclosure controls and procedures are effective at a reasonable assurance level.

There were no changes in third quarter 2018 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 2017 Annual Report.

Our significant accounting policies have remained unchanged since December 31, 2017 other than described below. A summary of our significant accounting policies is included in our 2017 Annual Report.

Changes in accounting policies for 2018

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 from these contracts in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in amounts that reflect the total consideration to which it expects to be entitled during the term of the contract in exchange for those promised goods or services. Goods or services that are promised to a customer are referred to as our "performance obligations." The total consideration to which we expect to be entitled can include fixed and variable amounts. We have variable revenue that is subject to factors outside of our influence, such as market prices, actions of third parties and weather conditions. We consider this variable revenue to be "constrained" as it cannot be reliably estimated, and therefore recognize variable revenue when the service is provided.

The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue recognition and related cash flows.

In the application of the new guidance, significant estimates and judgments are used to determine the following:

- pattern of revenue recognition within a contract, based on whether the performance obligation is satisfied at a point in time versus over time
- term of the contract
- amount of variable consideration associated with a contract and timing of the associated revenue recognition.

The new guidance was effective January 1, 2018, was applied using the modified retrospective transition method, and did not result in any material differences in the amount and timing of revenue recognition.

Financial instruments

In January 2016, the FASB issued new guidance on the accounting for equity investments and financial liabilities. The new guidance changes 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 our other deferred tax assets. This new guidance was effective January 1, 2018 and did not have a material impact 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 intra-entity asset transfers when the transfer occurs. The new guidance was effective January 1, 2018, was applied using a modified retrospective approach, and did not have a material impact 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 period and end of period total amounts on the statement of cash flows. This new guidance was effective January 1, 2018, was applied retrospectively, and did not have an impact on our consolidated financial statements.

Employee post-retirement benefits

In March 2017, the FASB issued new guidance that requires 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 was effective January 1, 2018 and did not have a material impact on our consolidated financial statements.

Hedge accounting

In August 2017, the FASB issued new guidance 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 requires additional disclosures including cumulative basis adjustments for fair value hedges and the effect of hedging on individual line items in the statement of income. This new guidance is effective January 1, 2019 with early adoption permitted. This new guidance, which we elected to adopt effective January 1, 2018, was applied prospectively and did not have a material impact on our consolidated financial statements.

Future accounting changes

Leases

In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessor is required 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. 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 statement of income. The new guidance does not make extensive changes to lessor accounting.

In January 2018, the FASB issued an optional practical expedient, to be applied upon transition, to omit the evaluation of land easements not previously accounted for as leases that existed or expired prior to the entity's adoption of the new lease guidance. An entity that elects this practical expedient is required to apply the practical expedient consistently to all of its existing or expired land easements not previously accounted for as leases. We intend to apply this practical expedient upon transition to the new standard.

The new guidance is effective January 1, 2019, with early adoption permitted. We will adopt the new standard on its effective date. A modified retrospective transition approach is required, applying the new standard to all leases existing at the date of initial application. In July 2018, the FASB issued a transition option allowing entities to not apply the new guidance, including disclosure requirements, to the comparative periods they present in their financial statements in the year of adoption. We will apply this transition option and therefore, will not be required to update financial information and disclosures for dates and periods prior to January 1, 2019.

We will elect the package of practical expedients which permits entities not to reassess prior conclusions about lease identification, lease classification and initial direct costs under the rules of the new standard. We continue to monitor and analyze other optional practical expedients as well as additional guidance and clarifications provided by the FASB.

We have developed an inventory of existing lease agreements, have substantially completed our analysis on them, but continue to refine our view of what qualifies as a lease and evaluate the financial impact on our consolidated financial statements. We have also selected a system solution and continue to progress through the testing stage of implementation. We continue to assess process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance and to analyze new contracts that may contain leases.

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 as 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.

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. We are currently evaluating the timing and impact of the adoption of this guidance.

Income taxes

In February 2018, the FASB issued new guidance that allows a reclassification from AOCI to retained earnings for stranded tax effects resulting from the U.S. Tax Reform. This new guidance is effective January 1, 2019, however, early adoption is permitted. This guidance can be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change is recognized. We are currently evaluating this guidance in conjunction with our analysis of the overall impact of U.S. Tax Reform.

Fair value measurement

In August 2018, the FASB issued new guidance that amends certain disclosure requirements for fair value measurements. This new guidance is effective January 1, 2020, however, early adoption of certain or all requirements is permitted. We are currently evaluating the timing and impact of adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Defined benefit plans

In August 2018, the FASB issued new guidance which amends and clarifies disclosure requirements related to defined benefit pension and other post retirement benefit plans. This new guidance is effective January 1, 2021, and will be applied on a retrospective basis. We are currently evaluating the timing and impact of the adoption of this guidance.

Implementation costs of cloud computing arrangements

In August 2018, the FASB issued new guidance requiring an entity in a hosting arrangement that is a service contract to follow the guidance for internal-use software to determine which implementation costs should be capitalized as an asset and which costs should be expensed. The guidance also requires the entity to amortize the capitalized implementation costs of a hosting arrangement over the term of the arrangement. This guidance is effective January 1, 2020, however, early adoption is permitted. This guidance can be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. We are currently evaluating the timing and impact of adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Reconciliation of non-GAAP measures

(unaudited - millions of $)	three months ended September 30 2018	three months ended September 30 2017	nine months ended September 30 2018	nine months ended September 30 2017
Comparable EBITDA				
Canadian Natural Gas Pipelines	**522**	544	**1,561**	1,575
U.S. Natural Gas Pipelines	**715**	482	**2,223**	1,753
Mexico Natural Gas Pipelines	**153**	118	**455**	403
Liquids Pipelines	**467**	303	**1,311**	947
Energy	**207**	224	**585**	816
Corporate	**(8)**	(4)	**(25)**	(20)
Comparable EBITDA	**2,056**	1,667	**6,110**	5,474
Depreciation and amortization	**(564)**	(506)	**(1,669)**	(1,532)
Comparable EBIT	**1,492**	1,161	**4,441**	3,942
Specific items:				
Foreign exchange (loss)/gain – inter-affiliate loan	**(60)**	7	**(52)**	(1)
U.S. Northeast power marketing contracts	**12**	—	**5**	—
Net (loss)/gain on sales of U.S. Northeast power generation assets	**—**	(12)	**—**	469
Integration and acquisition related costs – Columbia	**—**	(32)	**—**	(91)
Keystone XL asset costs	**—**	(10)	**—**	(23)
Risk management activities[1]	**(34)**	45	**(44)**	(102)
Segmented earnings	**1,410**	1,159	**4,350**	4,194

1

Risk management activities (unaudited - millions of $)	three months ended September 30 2018	three months ended September 30 2017	nine months ended September 30 2018	nine months ended September 30 2017
Canadian Power	**—**	1	**3**	5
U.S. Power	**31**	59	**(31)**	(97)
Liquids marketing	**(65)**	(19)	**(10)**	(15)
Natural Gas Storage	**—**	4	**(6)**	5
Total unrealized (losses)/gains from risk management activities	**(34)**	45	**(44)**	(102)

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

(unaudited - millions of $, except per share amounts)	2018			2017				2016
	Third	**Second**	**First**	**Fourth**	**Third**	**Second**	**First**	**Fourth**
Revenues	**3,156**	3,195	3,424	3,617	3,195	3,230	3,407	3,635
Net income/(loss) attributable to common shares	**928**	785	734	861	612	881	643	(358)
Comparable earnings	**902**	768	864	719	614	659	698	626
Per share statistics								
Net income/(loss) per common share - basic and diluted	**$1.02**	$0.88	$0.83	$0.98	$0.70	$1.01	$0.74	($0.43)
Comparable earnings per common share	**$1.00**	$0.86	$0.98	$0.82	$0.70	$0.76	$0.81	$0.75
Dividends declared per common share	**$0.69**	$0.69	$0.69	$0.625	$0.625	$0.625	$0.625	$0.565

FACTORS AFFECTING QUARTERLY FINANCIAL INFORMATION BY BUSINESS SEGMENT

Quarter-over-quarter revenues and net income fluctuate for reasons that 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:

- regulators' 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, annual revenues and net income are based on contracted and uncommitted spot transportation and liquids marketing activities. Quarter-over-quarter revenues and net income are affected by:

- regulatory decisions
- developments outside of the normal course of operations
- newly constructed assets being placed in service
- demand for uncontracted transportation services
- liquids marketing activities
- certain fair value adjustments.

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 part of our underlying operations.

In third quarter 2018, comparable earnings also excluded:

- after-tax income of $8 million related to our U.S. Northeast power marketing contracts. These were excluded from Energy's comparable earnings effective January 1, 2018 as the wind-down of these contracts is not considered part of our underlying operations.

In second quarter 2018, comparable earnings also excluded:

- an after-tax loss of $11 million related to our U.S. Northeast power marketing contracts. These were excluded from Energy's comparable earnings effective January 1, 2018 as the wind-down of these contracts is not considered part of our underlying operations.

In the first quarter 2018, comparable earnings also excluded:

- after-tax income of $6 million related to our U.S. Northeast power marketing contracts, primarily due to income recognized on the sale of our retail contracts. These were excluded from Energy's comparable earnings effective January 1, 2018 as the wind-down of these contracts is not considered part of our underlying operations.

In fourth quarter 2017, comparable earnings also excluded:

- an $804 million recovery of deferred income taxes as a result of U.S. Tax Reform
- a $136 million after-tax gain related to the sale of our Ontario solar assets
- a $64 million net after-tax gain related to the monetization of our U.S. Northeast power generation assets, which included an incremental after-tax loss of $7 million recorded on the sale of the thermal and wind package, $23 million of after-tax third-party insurance proceeds related to a 2017 Ravenswood outage and income tax adjustments
- a $954 million after-tax impairment charge for the Energy East pipeline and related projects as a result of our decision not to proceed with the project applications
- a $9 million after-tax charge related to the maintenance and liquidation of Keystone XL assets which were expensed pending further advancement of the project.

In third quarter 2017, comparable earnings also excluded:

- an incremental net loss of $12 million related to the monetization of our U.S. Northeast power generation assets, which included an incremental loss of $7 million after tax on the sale of the thermal and wind package and $14 million of after-tax disposition costs and income tax adjustments
- an after-tax charge of $30 million for integration-related costs associated with the acquisition of Columbia
- an after-tax charge of $8 million related to the maintenance of Keystone XL assets which were being expensed pending further advancement of the project.

In second quarter 2017, comparable earnings also excluded:

- a $265 million net after-tax gain related to the monetization of our U.S. Northeast power generation assets, which included a $441 million after-tax gain on the sale of TC Hydro and an additional 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 were being expensed pending further advancement of the project.

In first quarter 2017, comparable earnings also 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 generation business
- a charge of $7 million after tax related to the maintenance of Keystone XL assets which were 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 also excluded:

- an $870 million after-tax charge related to the loss on U.S. Northeast power assets held for sale which included an $863 million after-tax loss on the thermal and wind package held for sale and $7 million of after-tax costs related to the monetization
- an additional $68 million after-tax loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the Alberta PPA terminations
- an after-tax charge of $67 million for costs associated with the acquisition of Columbia which included a $44 million deferred tax adjustment upon acquisition and $23 million of retention, severance and integration costs
- an after-tax charge of $18 million related to Keystone XL costs for the maintenance and liquidation of project assets which were 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.

Condensed consolidated statement of income

(unaudited - millions of Canadian $, except per share amounts)	three months ended September 30		nine months ended September 30	
	2018	**2017**	**2018**	**2017**
Revenues				
Canadian Natural Gas Pipelines	**934**	921	**2,772**	2,725
U.S. Natural Gas Pipelines	**967**	811	**2,988**	2,684
Mexico Natural Gas Pipelines	**156**	139	**460**	432
Liquids Pipelines	**564**	437	**1,831**	1,410
Energy	**535**	887	**1,724**	2,581
	3,156	3,195	**9,775**	9,832
Income from Equity Investments	**147**	156	**492**	527
Operating and Other Expenses				
Plant operating costs and other	**884**	929	**2,580**	2,962
Commodity purchases resold	**318**	621	**1,239**	1,711
Property taxes	**127**	127	**429**	442
Depreciation and amortization	**564**	506	**1,669**	1,539
	1,893	2,183	**5,917**	6,654
(Loss)/Gain on Sales of Assets	**—**	(9)	**—**	489
Financial Charges				
Interest expense	**577**	504	**1,662**	1,528
Allowance for funds used during construction	**(147)**	(145)	**(365)**	(367)
Interest income and other	**(168)**	(84)	**(139)**	(193)
	262	275	**1,158**	968
Income before Income Taxes	**1,148**	884	**3,192**	3,226
Income Tax Expense				
Current	**30**	6	**169**	128
Deferred	**90**	182	**225**	653
	120	188	**394**	781
Net Income	**1,028**	696	**2,798**	2,445
Net income attributable to non-controlling interests	**59**	44	**229**	189
Net Income Attributable to Controlling Interests	**969**	652	**2,569**	2,256
Preferred share dividends	**41**	40	**122**	120
Net Income Attributable to Common Shares	**928**	612	**2,447**	2,136
Net Income per Common Share				
Basic	**$1.02**	$0.70	**$2.72**	$2.46
Diluted	**$1.02**	$0.70	**$2.72**	$2.45
Dividends Declared per Common Share	**$0.69**	$0.625	**$2.07**	$1.875
Weighted Average Number of Common Shares (millions)				
Basic	**906**	873	**898**	870
Diluted	**907**	875	**898**	872

See accompanying notes to the Condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian $)	**2018**	**2017**	**2018**	**2017**
Net Income	**1,028**	696	**2,798**	2,445
Other Comprehensive (Loss)/Income, Net of Income Taxes				
Foreign currency translation gains and losses on net investment in foreign operations	**(282)**	(370)	**409**	(721)
Reclassification of foreign currency translation gains on net investment on disposal of foreign operations	**—**	—	**—**	(77)
Change in fair value of net investment hedges	**9**	(1)	**(6)**	(3)
Change in fair value of cash flow hedges	**4**	1	**9**	4
Reclassification to net income of gains and losses on cash flow hedges	**6**	—	**16**	(1)
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	**10**	4	**10**	11
Other comprehensive income on equity investments	**6**	3	**18**	6
Other comprehensive (loss)/income	**(247)**	(361)	**456**	(779)
Comprehensive Income	**781**	335	**3,254**	1,666
Comprehensive income/(loss) attributable to non-controlling interests	**28**	(25)	**304**	31
Comprehensive Income Attributable to Controlling Interests	**753**	360	**2,950**	1,635
Preferred share dividends	**41**	40	**122**	120
Comprehensive Income Attributable to Common Shares	**712**	320	**2,828**	1,515

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 $)	**2018**	**2017**	**2018**	**2017**
Cash Generated from Operations				
Net income	**1,028**	696	**2,798**	2,445
Depreciation and amortization	**564**	506	**1,669**	1,539
Deferred income taxes	**90**	182	**225**	653
Income from equity investments	**(147)**	(156)	**(492)**	(527)
Distributions received from operating activities of equity investments	**296**	296	**761**	743
Employee post-retirement benefits funding, net of expense	**(22)**	(73)	**(22)**	(64)
Loss/(gain) on sales of assets	**—**	9	**—**	(489)
Equity allowance for funds used during construction	**(104)**	(107)	**(261)**	(249)
Unrealized (gains)/losses on financial instruments	**(29)**	(77)	**120**	14
Other	**(93)**	(5)	**(152)**	(1)
Increase in operating working capital	**(284)**	(86)	**(130)**	(224)
Net cash provided by operations	**1,299**	1,185	**4,516**	3,840
Investing Activities				
Capital expenditures	**(2,435)**	(2,031)	**(6,474)**	(5,383)
Capital projects in development	**(127)**	(37)	**(239)**	(135)
Contributions to equity investments	**(236)**	(475)	**(778)**	(1,140)
Proceeds from sales of assets, net of transaction costs	**—**	—	**—**	4,147
Other distributions from equity investments	**—**	—	**121**	362
Deferred amounts and other	**(16)**	165	**78**	(87)
Net cash used in investing activities	**(2,814)**	(2,378)	**(7,292)**	(2,236)
Financing Activities				
Notes payable issued, net	**1,421**	451	**1,906**	1,232
Long-term debt issued, net of issue costs	**1,026**	1,151	**4,359**	1,968
Long-term debt repaid	**(1,232)**	(46)	**(3,266)**	(5,515)
Junior subordinated notes issued, net of issue costs	**—**	(3)	**—**	3,468
Dividends on common shares	**(416)**	(354)	**(1,154)**	(982)
Dividends on preferred shares	**(40)**	(39)	**(118)**	(116)
Distributions paid to non-controlling interests	**(57)**	(66)	**(174)**	(215)
Common shares issued, net of issue costs	**354**	6	**1,139**	42
Partnership units of TC PipeLines, LP issued, net of issue costs	**—**	43	**49**	162
Common units of Columbia Pipeline Partners LP acquired	**—**	—	**—**	(1,205)
Net cash provided by/(used in) financing activities	**1,056**	1,143	**2,741**	(1,161)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(10)**	(16)	**47**	(35)
(Decrease)/increase in Cash and Cash Equivalents	**(469)**	(66)	**12**	408
Cash and Cash Equivalents				
Beginning of period	**1,570**	1,490	**1,089**	1,016
Cash and Cash Equivalents				
End of period	**1,101**	1,424	**1,101**	1,424

See accompanying notes to the Condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		September 30, 2018	December 31, 2017
ASSETS			
Current Assets			
Cash and cash equivalents		**1,101**	1,089
Accounts receivable		**2,170**	2,522
Inventories		**381**	378
Assets held for sale		**458**	—
Other		**1,003**	691
		5,113	4,680
Plant, Property and Equipment	net of accumulated depreciation of $25,206 and $23,734, respectively	**63,212**	57,277
Equity Investments		**6,683**	6,366
Regulatory Assets		**1,391**	1,376
Goodwill		**13,504**	13,084
Loan Receivable from Affiliate		**1,244**	919
Intangible and Other Assets		**1,929**	1,484
Restricted Investments		**1,101**	915
		94,177	86,101
LIABILITIES			
Current Liabilities			
Notes payable		**3,742**	1,763
Accounts payable and other		**4,301**	4,057
Dividends payable		**643**	586
Accrued interest		**604**	605
Current portion of long-term debt		**1,671**	2,866
		10,961	9,877
Regulatory Liabilities		**4,603**	4,321
Other Long-Term Liabilities		**637**	727
Deferred Income Tax Liabilities		**5,824**	5,403
Long-Term Debt		**35,029**	31,875
Junior Subordinated Notes		**7,186**	7,007
		64,240	59,210
EQUITY			
Common shares, no par value		**22,951**	21,167
Issued and outstanding:	September 30, 2018 - 914 million shares		
	December 31, 2017 - 881 million shares		
Preferred shares		**3,980**	3,980
Additional paid-in capital		**15**	—
Retained earnings		**2,318**	1,623
Accumulated other comprehensive loss		**(1,350)**	(1,731)
Controlling Interests		**27,914**	25,039
Non-controlling interests		**2,023**	1,852
		29,937	26,891
		94,177	86,101

Contingencies and Guarantees (Note 13)
Variable Interest Entities (Note 14)
Subsequent Events (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 $)	**2018**	**2017**
Common Shares		
Balance at beginning of period	**21,167**	20,099
Shares issued:		
Under at-the-market equity program, net of issue costs	**1,118**	—
Under dividend reinvestment and share purchase plan	**640**	599
On exercise of stock options	**26**	46
Balance at end of period	**22,951**	20,744
Preferred Shares		
Balance at beginning and end of period	**3,980**	3,980
Additional Paid-In Capital		
Balance at beginning of period	**—**	—
Issuance of stock options, net of exercises	**8**	4
Dilution from TC PipeLines, LP units issued	**7**	18
Asset drop downs to TC PipeLines, LP	**—**	(202)
Columbia Pipeline Partners LP acquisition	**—**	(171)
Reclassification of additional paid-in capital deficit to retained earnings	**—**	351
Balance at end of period	**15**	—
Retained Earnings		
Balance at beginning of period	**1,623**	1,138
Net income attributable to controlling interests	**2,569**	2,256
Common share dividends	**(1,869)**	(1,633)
Preferred share dividends	**(100)**	(98)
Adjustment related to income tax effects of asset drop downs to TC PipeLines, LP	**95**	—
Adjustment related to employee share-based payments	**—**	12
Reclassification of additional paid-in capital deficit to retained earnings	**—**	(351)
Balance at end of period	**2,318**	1,324
Accumulated Other Comprehensive Loss		
Balance at beginning of period	**(1,731)**	(960)
Other comprehensive income/(loss) attributable to controlling interests	**381**	(621)
Balance at end of period	**(1,350)**	(1,581)
Equity Attributable to Controlling Interests	**27,914**	24,467
Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	**1,852**	1,726
Net income attributable to non-controlling interests	**229**	189
Other comprehensive income/(loss) attributable to non-controlling interests	**75**	(158)
Issuance of TC PipeLines, LP units		
Proceeds, net of issue costs	**49**	162
Decrease in TransCanada's ownership of TC PipeLines, LP	**(9)**	(29)
Distributions declared to non-controlling interests	**(173)**	(212)
Reclassification from common units of TC PipeLines, LP subject to rescission	**—**	106
Impact of Columbia Pipeline Partners LP acquisition	**—**	33
Balance at end of period	**2,023**	1,817
Total Equity	**29,937**	26,284

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, 2017, except as described in Note 2, Accounting changes. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in the 2017 audited consolidated financial statements included in TransCanada's 2017 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 2017 audited consolidated financial statements included in TransCanada's 2017 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, 2017, except as described in Note 2, Accounting changes.

2. Accounting changes

CHANGES IN ACCOUNTING POLICIES FOR 2018

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 from these contracts in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in amounts that reflect the total consideration to which it expects to be entitled during the term of the contract in exchange for those promised goods or services. Goods or services that are promised to a customer are referred to as the Company's "performance obligations." The total consideration to which the Company expects to be entitled can include fixed and variable amounts. The Company has variable revenue that is subject to factors outside the Company's influence, such as market prices, actions of third parties and weather conditions. The Company considers this variable revenue to be "constrained" as it cannot be reliably estimated, and therefore recognizes variable revenue when the service is provided.

The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue recognition and related cash flows.

In the application of the new guidance, significant estimates and judgments are used to determine the following:

- pattern of revenue recognition within a contract, based on whether the performance obligation is satisfied at a point in time versus over time
- term of the contract
- amount of variable consideration associated with a contract and timing of the associated revenue recognition.

The new guidance was effective January 1, 2018, was applied using the modified retrospective transition method, and did not result in any material differences in the amount and timing of revenue recognition. Refer to Note 4, Revenues, for further information related to the impact of adopting the new guidance and the Company's updated accounting policies related to revenue recognition from contracts with customers.

Financial instruments

In January 2016, the FASB issued new guidance on the accounting for equity investments and financial liabilities. The new guidance changes 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 was effective January 1, 2018 and did not have a material impact on the Company's 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 intra-entity asset transfers when the transfer occurs. The new guidance was effective January 1, 2018, was applied using a modified retrospective approach, and did not have a material impact on the Company's 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 period and end of period total amounts on the statement of cash flows. This new guidance was effective January 1, 2018, was applied retrospectively, and did not have an impact on the Company's consolidated financial statements.

Employee post-retirement benefits

In March 2017, the FASB issued new guidance that requires 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 was effective January 1, 2018 and did not have a material impact on the Company's consolidated financial statements.

Hedge accounting

In August 2017, the FASB issued new guidance 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 requires additional disclosures including cumulative basis adjustments for fair value hedges and the effect of hedging on individual line items in the statement of income. This new guidance is effective January 1, 2019 with early adoption permitted. This new guidance, which the Company elected to adopt effective January 1, 2018, was applied prospectively and did not have a material impact on the Company's consolidated financial statements.

FUTURE ACCOUNTING CHANGES

Leases

In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessor is required 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. 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 statement of income. The new guidance does not make extensive changes to lessor accounting.

In January 2018, the FASB issued an optional practical expedient, to be applied upon transition, to omit the evaluation of land easements not previously accounted for as leases that existed or expired prior to the entity's adoption of the new lease guidance. An entity that elects this practical expedient is required to apply the practical expedient consistently to all of its existing or expired land easements not previously accounted for as leases. The Company intends to apply this practical expedient upon transition to the new standard.

The new guidance is effective January 1, 2019, with early adoption permitted. The Company will adopt the new standard on its effective date. A modified retrospective transition approach is required, applying the new standard to all leases existing at the date of initial application. In July 2018, the FASB issued a transition option allowing entities to not apply the new guidance, including disclosure requirements, to the comparative periods they present in their financial statements in the year of adoption. The Company will apply this transition option and therefore will not be required to update financial information and disclosures for dates and periods prior to January 1, 2019.

The Company will elect the package of practical expedients which permits entities not to reassess prior conclusions about lease identification, lease classification and initial direct costs under the rules of the new standard. The Company continues to monitor and analyze other optional practical expedients as well as additional guidance and clarifications provided by the FASB.

The Company has developed an inventory of existing lease agreements, has substantially completed its analysis on them, but continues to refine its view of what qualifies as a lease and evaluate the financial impact on its consolidated financial statements. The Company has also selected a system solution and continues to progress through the testing stage of implementation. The Company continues to assess process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance and to analyze new contracts that may contain leases.

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 as 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.

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. The Company is currently evaluating the timing and impact of the adoption of this guidance.

Income taxes

In February 2018, the FASB issued new guidance that allows a reclassification from AOCI to retained earnings for stranded tax effects resulting from the U.S. Tax Reform. This new guidance is effective January 1, 2019, however, early adoption is permitted. This guidance can be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change is recognized. The Company is currently evaluating this guidance in conjunction with its analysis of the overall impact of U.S. Tax Reform.

Fair value measurement

In August 2018, the FASB issued new guidance that amends certain disclosure requirements for fair value measurements. This new guidance is effective January 1, 2020, however, early adoption of certain or all requirements is permitted. The Company is currently evaluating the timing and impact of adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

Defined benefit plans

In August 2018, the FASB issued new guidance which amends and clarifies disclosure requirements related to defined benefit pension and other post retirement benefit plans. This new guidance is effective January 1, 2021, and will be applied on a retrospective basis. The Company is currently evaluating the timing and impact of the adoption of this guidance.

Implementation costs of cloud computing arrangements

In August 2018, the FASB issued new guidance requiring an entity in a hosting arrangement that is a service contract to follow the guidance for internal-use software to determine which implementation costs should be capitalized as an asset and which costs should be expensed. The guidance also requires the entity to amortize the capitalized implementation costs of a hosting arrangement over the term of the arrangement. This guidance is effective January 1, 2020, however, early adoption is permitted. This guidance can be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. The Company is currently evaluating the timing and impact of adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

3. Segmented information

three months ended September 30, 2018 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**[1]	**Total**
Revenues	**934**	**967**	**156**	**564**	**535**	**—**	**3,156**
Intersegment revenues	**—**	**40**	**—**	**—**	**3**	**(43)** [2]	**—**
	934	**1,007**	**156**	**564**	**538**	**(43)**	**3,156**
Income/(loss) from equity investments	**3**	**62**	**8**	**22**	**112**	**(60)** [3]	**147**
Plant operating costs and other	**(356)**	**(313)**	**(11)**	**(160)**	**(79)**	**35** [2]	**(884)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(318)**	**—**	**(318)**
Property taxes	**(59)**	**(41)**	**—**	**(24)**	**(3)**	**—**	**(127)**
Depreciation and amortization	**(255)**	**(170)**	**(26)**	**(86)**	**(27)**	**—**	**(564)**
Segmented Earnings/(Loss)	**267**	**545**	**127**	**316**	**223**	**(68)**	**1,410**
Interest expense							**(577)**
Allowance for funds used during construction							**147**
Interest income and other[3]							**168**
Income before income taxes							**1,148**
Income tax expense							**(120)**
Net Income							**1,028**
Net income attributable to non-controlling interests							**(59)**
Net Income Attributable to Controlling Interests							**969**
Preferred share dividends							**(41)**
Net Income Attributable to Common Shares							**928**

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Income/(loss) from equity investments includes foreign exchange losses on the Company's inter-affiliate loan with Sur de Texas. The offsetting foreign exchange gains on the inter-affiliate loan are included in Interest income and other. The peso-denominated loan to the Sur de Texas joint venture represents the Company's proportionate share of debt financing for this joint venture.

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**[1]	**Total**
Revenues	921	811	139	437	887	—	3,195
Intersegment revenues	—	10	—	—	—	(10) [2]	—
	921	821	139	437	887	(10)	3,195
Income/(loss) from equity investments	4	53	(11)	4	99	7 [3]	156
Plant operating costs and other	(318)	(351)	(10)	(145)	(79)	(26) [2]	(929)
Commodity purchases resold	—	—	—	—	(621)	—	(621)
Property taxes	(63)	(41)	—	(22)	(1)	—	(127)
Depreciation and amortization	(228)	(145)	(23)	(71)	(39)	—	(506)
Loss on sales 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[3]							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

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Income/(loss) from equity investments includes foreign exchange gains on the Company's inter-affiliate loan with Sur de Texas. The offsetting foreign exchange losses on the inter-affiliate loan are included in Interest income and other. The peso-denominated loan to the Sur de Texas joint venture represents the Company's proportionate share of debt financing for this joint venture.

nine months ended September 30, 2018 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**[1]	**Total**
Revenues	**2,772**	**2,988**	**460**	**1,831**	**1,724**	**—**	**9,775**
Intersegment revenues	**—**	**121**	**—**	**—**	**50**	**(171)** [2]	**—**
	2,772	**3,109**	**460**	**1,831**	**1,774**	**(171)**	**9,775**
Income/(loss) from equity investments	**9**	**188**	**20**	**50**	**277**	**(52)** [3]	**492**
Plant operating costs and other	**(1,020)**	**(925)**	**(25)**	**(506)**	**(250)**	**146** [2]	**(2,580)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(1,239)**	**—**	**(1,239)**
Property taxes	**(200)**	**(149)**	**—**	**(74)**	**(6)**	**—**	**(429)**
Depreciation and amortization	**(761)**	**(489)**	**(73)**	**(254)**	**(92)**	**—**	**(1,669)**
Segmented Earnings/(Loss)	**800**	**1,734**	**382**	**1,047**	**464**	**(77)**	**4,350**
Interest expense							**(1,662)**
Allowance for funds used during construction							**365**
Interest income and other[3]							**139**
Income before income taxes							**3,192**
Income tax expense							**(394)**
Net Income							**2,798**
Net income attributable to non-controlling interests							**(229)**
Net Income Attributable to Controlling Interests							**2,569**
Preferred share dividends							**(122)**
Net Income Attributable to Common Shares							**2,447**

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Income/(loss) from equity investments includes foreign exchange losses on the Company's inter-affiliate loan with Sur de Texas. The offsetting foreign exchange gains on the inter-affiliate loan are included in Interest income and other. The peso-denominated loan to the Sur de Texas joint venture represents the Company's proportionate share of debt financing for this joint venture.

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**[1]	**Total**
Revenues	2,725	2,684	432	1,410	2,581	—	9,832
Intersegment revenues	—	31	—	—	—	(31) [2]	—
	2,725	2,715	432	1,410	2,581	(31)	9,832
Income/(loss) from equity investments	9	175	—	3	341	(1) [3]	527
Plant operating costs and other	(958)	(1,004)	(29)	(437)	(464)	(70) [2]	(2,962)
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 sales 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[3]							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

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Income/(loss) from equity investments includes foreign exchange losses on the Company's inter-affiliate loan with Sur de Texas. The offsetting foreign exchange gains on the inter-affiliate loan are included in Interest income and other. The peso-denominated loan to the Sur de Texas joint venture represents the Company's proportionate share of debt financing for this joint venture.

TOTAL ASSETS

(unaudited - millions of Canadian $)	**September 30, 2018**	**December 31, 2017**
Canadian Natural Gas Pipelines	**17,900**	16,904
U.S. Natural Gas Pipelines	**41,045**	35,898
Mexico Natural Gas Pipelines	**6,403**	5,716
Liquids Pipelines	**16,277**	15,438
Energy	**8,559**	8,503
Corporate	**3,993**	3,642
	94,177	86,101

4. Revenues

In 2014, the FASB issued new guidance on revenue from contracts with customers. The Company adopted the new guidance on January 1, 2018 using the modified retrospective transition method for all contracts that were in effect on the date of adoption. Results reported for 2018 reflect the application of the new guidance, while the 2017 comparative results were prepared and reported under previous revenue recognition guidance which is referred to herein as "legacy U.S. GAAP."

DISAGGREGATION OF REVENUES

The following tables summarize total Revenues for the three and nine months ended September 30, 2018:

three months ended September 30, 2018 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Total**
Revenues from contracts with customers						
Capacity arrangements and transportation	934	788	155	511	—	2,388
Power generation	—	—	—	—	450	450
Natural gas storage and other	—	158	1	1	4	164
	934	946	156	512	454	3,002
Other revenues[1,2]	—	21	—	52	81	154
	934	967	156	564	535	3,156

1 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements within each operating segment. Income from lease arrangements includes certain long term PPAs, as well as certain liquids pipelines capacity and transportation arrangements. These arrangements are not in the scope of the new guidance, therefore, revenues related to these contracts are excluded from revenues from contracts with customers. Refer to Note 12, Risk management and financial instruments, for further information on income from financial instruments.

2 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from U.S. Tax Reform. Refer to Note 7, Income taxes, for further information.

nine months ended September 30, 2018 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Total**
Revenues from contracts with customers						
Capacity arrangements and transportation	2,772	2,457	457	1,558	—	7,244
Power generation	—	—	—	—	1,455	1,455
Natural gas storage and other	—	468	3	2	65	538
	2,772	2,925	460	1,560	1,520	9,237
Other revenues[1,2]	—	63	—	271	204	538
	2,772	2,988	460	1,831	1,724	9,775

1 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements within each operating segment. Income from lease arrangements includes certain long term PPAs, as well as certain liquids pipelines capacity and transportation arrangements. These arrangements are not in the scope of the new guidance, therefore, revenues related to these contracts are excluded from revenues from contracts with customers. Refer to Note 12, Risk management and financial instruments, for further information on income from financial instruments.

2 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from U.S. Tax Reform. Refer to Note 7, Income taxes, for further information.

Revenues from contracts with customers are recognized net of any taxes collected from customers which are subsequently remitted to governmental authorities. The Company's contracts with customers include natural gas and liquids pipelines capacity arrangements and transportation contracts, power generation contracts, natural gas storage and other contracts.

Canadian Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's Canadian natural gas pipelines are generated from contractual arrangements for committed capacity and from the transportation of natural gas. Revenues earned from firm contracted capacity arrangements are recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed.

Revenues from the Company's Canadian natural gas pipelines are subject to regulatory decisions by the NEB. The tolls charged on these pipelines are based on revenue requirements designed to recover the costs of providing natural gas capacity for transportation services, which includes a return of and return on capital, as approved by the NEB. The Company's Canadian natural gas pipelines are generally not subject to risks related to variances in revenues and most costs. These variances are generally subject to deferral treatment and are recovered or refunded in future tolls. Revenues recognized prior to an NEB decision on rates for that period reflect the NEB's last approved ROE assumptions. Adjustments to revenues are recorded when the NEB decision is received. Canadian natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

U.S. Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's U.S. natural gas pipelines are generated from contractual arrangements for committed capacity and from the transportation of natural gas. Revenues earned from firm contracted capacity arrangements are generally recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed. The Company has elected to utilize the practical expedient to recognize revenues from its U.S. natural gas pipelines as invoiced.

The Company's U.S. natural gas pipelines are subject to FERC regulations and, as a result, a portion of revenues collected may be subject to refund if invoiced during an interim period when a rate proceeding is ongoing. Allowances for these potential refunds are recognized using management's best estimate based on the facts and circumstances of the proceeding. Any allowances that are recognized during the proceeding process are refunded or retained at the time a regulatory decision becomes final. U.S. natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Natural Gas Storage and Other

Revenues from the Company's regulated U.S. natural gas storage services are generated mainly from firm committed capacity storage contracts. The performance obligation in these contracts is the reservation of a specified amount of capacity for storage including specifications with regards to the amount of natural gas that can be injected or withdrawn on a daily basis. Revenues are recognized ratably over the contract period for firm committed capacity regardless of the amount of natural gas that is stored, and when gas is injected or withdrawn for interruptible or volumetric-based services. Natural gas storage services revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it stores for customers.

Revenues from the Company's midstream natural gas services, including gathering, treating, conditioning, processing, compression and liquids handling services, are generated from contractual arrangements and are recognized ratably over the term of the contract. The Company also owns mineral rights associated with certain natural gas storage facilities. These mineral rights can be leased or contributed to producers of natural gas in return for a royalty interest which is recognized when natural gas and associated liquids are produced. Midstream natural gas service revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas for which it provides midstream services.

Mexico Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's Mexico natural gas pipelines are primarily collected based on CRE-approved negotiated firm capacity contracts and are generally recognized ratably over the term of the contract. For certain firm capacity arrangements, the Company has elected to utilize the practical expedient to recognize revenues as invoiced. Transportation revenues related to interruptible or volumetric-based services are recognized when the service is performed. Other volumes shipped on these pipelines are subject to CRE-approved tariffs and revenues are recognized when the Company has performed the transportation services. Mexico natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Liquids Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's liquids pipelines are generated mainly from providing customers with firm capacity arrangements to transport crude oil. The performance obligation in these contracts is the reservation of a specified amount of capacity together with the transportation of crude oil on a monthly basis. Revenues earned from these arrangements are recognized ratably over the term of the contract regardless of the amount of crude oil that is transported. Revenues for interruptible or volumetric-based services are recognized when the service is performed. Liquids pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the crude oil that it transports for customers.

Energy

Power Generation

Revenues from the Company's Energy business are primarily derived from long-term contractual commitments to provide power capacity to meet the demands of the market, and from the sale of electricity to both centralized markets and to customers. Power generation revenues also include revenues from the sale of steam to customers. Revenues and capacity payments are recognized as the services are provided and as electricity and steam is delivered. Power generation revenues are invoiced and received on a monthly basis.

Natural Gas Storage and Other

Non-regulated natural gas storage contracts include park, loan and term storage arrangements. Park and loan contracts allow for fixed injection or withdrawal volumes on specified dates for a specified price. Term storage contracts allow for a maximum amount of gas to be stored over a set period of time. Revenues from park and loan contracts are recognized and invoiced as the injection and withdrawal services are provided and revenues from term storage contracts are recognized ratably over the term of the contract. Term storage revenues are invoiced and received on a monthly basis. Revenues earned from the sale of proprietary natural gas are recognized in the month of delivery. Revenues from ancillary services are recognized as the service is provided. The Company does not take ownership of the natural gas that it stores for customers.

FINANCIAL STATEMENT IMPACT OF ADOPTING REVENUE FROM CONTRACTS WITH CUSTOMERS

The Company adopted the new guidance using the modified retrospective transition method. As a practical expedient under this transition method, the Company is not required to analyze completed contracts at the date of adoption. As a result, the Company made the following adjustments on January 1, 2018.

Capacity Arrangements and Transportation

For certain natural gas pipelines capacity contracts, amounts are invoiced to the customer in accordance with the terms of the contract, however, the related revenues are recognized when the Company satisfies its performance obligation to provide committed capacity ratably over the term of the contract. This difference in timing between revenue recognition and amounts invoiced creates a contract asset or contract liability under the new revenue recognition guidance. Under legacy U.S. GAAP, this difference was recorded as Accounts receivable. Under the new guidance, contract assets are included in Other current assets and Intangibles and other assets and contract liabilities are included in Accounts payable and other and Other long-term liabilities.

Impact of New Revenue Recognition Guidance on Date of Adoption

The following table illustrates the impact of the adoption of the new revenue recognition guidance on the Company's previously reported consolidated balance sheet line items:

(unaudited - millions of Canadian $)	As reported December 31, 2017	Adjustment	January 1, 2018
Current Assets			
Accounts receivable	2,522	(62)	2,460
Other[1]	691	79	770
Current Liabilities			
Accounts payable and other[2]	4,057	17	4,074

1 Adjustment relates to contract assets previously included in Accounts receivable.
2 Adjustment relates to contract liabilities previously included in Accounts receivable.

Pro-forma Financial Statements under Legacy U.S. GAAP

As required by the new revenue recognition guidance, the following tables illustrate the pro-forma impact on the affected line items on the Condensed consolidated balance sheet, as at September 30, 2018, using legacy U.S. GAAP:

	September 30, 2018	
(unaudited - millions of Canadian $)	As reported	Pro-forma using legacy U.S. GAAP
Current Assets		
Accounts receivable	**2,170**	**2,460**
Other	**1,003**	**713**

CONTRACT BALANCES

(unaudited - millions of Canadian $)	September 30, 2018	January 1, 2018
Receivables from contracts with customers	**1,208**	1,736
Contract assets[1]	**290**	79
Long-term contract assets[2]	**35**	—
Contract liabilities[3]	**41**	17
Long-term contract liabilities[4]	**27**	—

1 Recorded as part of Other current assets on the Condensed consolidated balance sheet.
2 Recorded as part of Intangibles and other assets on the Condensed consolidated balance sheet.
3 Comprised of deferred revenue recorded in Accounts payable and other on the Condensed consolidated balance sheet. During the nine months ended September 30, 2018, $17 million of revenue was recognized that was included in the contract liability at the beginning of the period.
4 Comprised of deferred revenue recorded in Other long-term liabilities on the Condensed consolidated balance sheet.

Contract assets and long-term contract assets primarily relate to the Company’s right to revenues for services completed but not invoiced at the reporting date on long-term committed capacity natural gas pipelines contracts. The change in contract assets is primarily related to the transfer to Accounts receivable when these rights become unconditional and the customer is invoiced as well as the recognition of additional revenues that remains to be invoiced. Contract liabilities and long term contract liabilities primarily relate to force majeure fixed capacity payments received on long term capacity arrangements in Mexico.

FUTURE REVENUES FROM REMAINING PERFORMANCE OBLIGATIONS

As required by the new revenue recognition guidance, the following provides disclosure on future revenues allocated to remaining performance obligations representing contracted revenues that have not yet been recognized. Certain contracts that qualify for the use of one of the following practical expedients are excluded from the future revenues disclosures:

1) The original expected duration of the contract is one year or less.
2) The Company recognizes revenue from the contract that is equal to the amount invoiced, where the amount invoiced represents the value to the customer of the service performed to date. This is referred to as the "right to invoice" practical expedient.
3) The variable revenue generated from the contract is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct good or service that forms part of a single performance obligation in a series. A single performance obligation in a series occurs when the promises under a contract are a series of distinct services that are substantially the same and have the same pattern of transfer to the customer over time.

The following provides a discussion of the transaction price allocated to future performance obligations as well as practical expedients used by the Company.

Capacity Arrangements and Transportation

As at September 30, 2018, future revenues from long-term capacity arrangements and transportation contracts extending through 2043 are approximately $28.0 billion, of which approximately $1.4 billion is expected to be recognized during the remainder of 2018.

Future revenues from long-term capacity arrangements and transportation contracts do not include constrained variable revenues or arrangements to which the right to invoice practical expedient has been applied. As a result, these amounts are not representative of potential total future revenues expected from these contracts.

Future revenues from the Company's Canadian natural gas pipelines' regulated firm capacity contracts include fixed revenues for the time periods that tolls under current rate settlements are in effect, which is approximately one to three years. Many of these contracts are long-term in nature and revenues from the remaining performance obligations that extend beyond the current rate settlement term are considered to be fully constrained since future tolls remain unknown. Revenues from these contracts will be recognized once the performance obligation to provide capacity has been satisfied and the regulator has approved the applicable tolls. In addition, the Company considers interruptible transportation service revenues to be variable revenues since volumes cannot be estimated. These variable revenues are recognized on a monthly basis when the Company satisfies the performance obligation and have been excluded from the future revenues disclosure as the Company applies the practical expedient related to variable revenues to these contracts. The future variable revenues earned under these contracts are allocated entirely to unsatisfied performance obligations at September 30, 2018.

The Company also applies the right to invoice practical expedient to all of its U.S. and certain of its Mexico regulated natural gas pipeline capacity arrangements and flow-through revenues. Revenues from regulated capacity arrangements are recognized based on current rates and flow-through revenues are earned from the recovery of operating expenses. These revenues are recognized on a monthly basis as the Company performs the services and are excluded from future revenues disclosures.

Revenues from liquids pipelines capacity arrangements have a variable component based on volumes transported. As a result, these variable revenues are excluded from the future revenues disclosures as the Company applies the practical expedient related to variable revenues to these contracts. The future variable revenues earned under these contracts is allocated entirely to unsatisfied performance obligations at September 30, 2018.

Power Generation

The Company has long-term power generation contracts extending through 2032. Revenues from power generation have a variable component related to market prices that are subject to factors outside the Company's influence. These revenues are considered to be fully constrained and are recognized on a monthly basis when the Company satisfies the performance obligation. The Company applies the practical expedient related to variable revenues to these contracts. As a result, future revenues from these contracts are excluded from the disclosures.

Natural Gas Storage and Other

As at September 30, 2018, future revenues from long-term natural gas storage and other contracts extending through 2033 are approximately $1.2 billion, of which approximately $127 million is expected to be recognized during the remainder of 2018. The Company applies the practical expedients related to contracts that are for a duration of one year or less and where it recognizes variable consideration, and therefore excludes the related revenues from the future revenues disclosure. As a result, this amount is lower than the potential total future revenues from these contracts.

5. Assets held for sale

Cartier Wind

On August 1, 2018, TransCanada entered into an agreement to sell its interests in the Cartier Wind power facilities in Québec to Innergex Renewable Energy Inc. At September 30, 2018, the related assets and liabilities were classified as held for sale in the Energy segment. Subsequently, on October 24, 2018, the Company closed the sale for gross proceeds of approximately $630 million before closing adjustments, resulting in an estimated gain of $170 million ($135 million after tax) to be recognized in fourth quarter 2018.

At September 30, 2018, the related assets and liabilities in the Energy segment were classified as held for sale as follows:

(unaudited - millions of Canadian $)	
Assets held for sale	
Plant, property and equipment	**458**
Total assets held for sale	**458**
Liabilities related to assets held for sale	
Other long-term liabilities	**14**
Total liabilities related to assets held for sale[1]	**14**

1 Included in Accounts payable and other on the Condensed consolidated balance sheet.

6. Plant, Property and Equipment, Equity Investments and Goodwill

The Company reviews plant, property and equipment and equity investments for impairment whenever events or changes in circumstances indicate the carrying value of the asset may not be recoverable.

Goodwill is tested for impairment on an annual basis or more frequently if events or changes in circumstance indicate that it might be impaired. The Company can initially make this assessment based on qualitative factors. If the Company concludes that it is not more likely than not that the fair value of the reporting unit is less than its carrying value, then an impairment test is not performed.

In March 2018, FERC proposed changes related to U.S. Tax Reform and income taxes for rate-making purposes in a master limited partnership (MLP) that may have an impact on the future earnings and cash flows of FERC-regulated pipelines. On July 18, 2018, FERC issued final rulings (Final Rule) with respect to these changes. The March and July 2018 FERC proposed changes and Final Rule are collectively referred to herein as the "2018 FERC Actions."

The Company continues to monitor developments following the Final Rule on the 2018 FERC Actions. TransCanada will incorporate results to date, future filings for individual pipelines, as well as FERC responses to others in the industry into its annual goodwill impairment tests as well as its normal review of plant, property and equipment and equity investments for recoverability.

As at September 30, 2018, the goodwill balances related to Great Lakes and Tuscarora are US$573 million and US$82 million (December 31, 2017 – US$573 million and US$82 million), respectively. At December 31, 2017, the estimated fair value of Great Lakes exceeded its carrying value by less than 10 per cent. There is a risk that the goodwill balances related to both of these assets could be negatively impacted by the FERC developments, once finalized, or by other changes in management's estimates of fair value resulting in a goodwill impairment charge.

7. Income taxes

U.S. Tax Reform

Pursuant to the enactment of U.S. Tax Reform, the Company recorded net regulatory liabilities and a corresponding reduction in net deferred income tax liabilities in the amount of $1,686 million at December 31, 2017 related to the Company's U.S. natural gas pipelines subject to RRA. Amounts recorded to adjust income taxes remain provisional as the Company's interpretation, assessment and presentation of the impact of U.S. Tax Reform may be further clarified with additional guidance from tax authorities. Should additional guidance be provided by tax authorities during the one-year measurement period permitted by the SEC, the Company will review the provisional amounts and adjust as appropriate.

Commencing January 1, 2018, the Company has amortized the net regulatory liabilities using the Reverse South Georgia methodology. Under this methodology, rate-regulated entities determine and immediately begin recording amortization based on their composite depreciation rates. Amortization of the net regulatory liabilities in the amount of $12 million and $36 million was recorded for the three and nine months ended September 30, 2018, respectively, and included in Revenues in the Condensed consolidated statement of income. Once the final impact of the 2018 FERC Actions is determined there may be prospective adjustments to the Company's net regulatory liabilities.

Effective Tax Rates

The effective income tax rates for the nine-month periods ended September 30, 2018 and 2017 were 12 per cent and 24 per cent, respectively. The lower effective tax rate in 2018 was primarily the result of the rate change resulting from U.S. Tax Reform and lower flow-through income taxes in Canadian rate-regulated pipelines.

8. Long-term debt

LONG-TERM DEBT ISSUED

The Company issued long-term debt in the nine months ended September 30, 2018 as follows:

(unaudited - millions of Canadian $, unless noted otherwise) Company	Issue date	Type	Maturity Date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	July 2018	Medium Term Notes	July 2048	800	4.18%
	July 2018	Medium Term Notes	March 2028	200	3.39%
	May 2018	Senior Unsecured Notes	May 2028	US 1,000	4.25%
	May 2018	Senior Unsecured Notes	May 2038	US 500	4.75%
	May 2018	Senior Unsecured Notes	May 2048	US 1,000	4.875%

LONG-TERM DEBT RETIRED

The Company retired long-term debt in the nine months ended September 30, 2018 as follows:

(unaudited - millions of Canadian $, unless noted otherwise) Company	Retirement date	Type	Amount	Interest rate
COLUMBIA PIPELINE GROUP, INC.				
	June 2018	Senior Unsecured Notes	US 500	2.45%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM				
	May 2018	Senior Secured Notes	US 18	5.90%
TRANSCANADA PIPELINES LIMITED				
	August 2018	Senior Unsecured Notes	US 850	6.50%
	March 2018	Debentures	150	9.45%
	January 2018	Senior Unsecured Notes	US 500	1.875%
	January 2018	Senior Unsecured Notes	US 250	Floating
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP				
	March 2018	Senior Unsecured Notes	US 9	6.73%

CAPITALIZED INTEREST

In the three and nine months ended September 30, 2018, TransCanada capitalized interest related to capital projects of $33 million and $89 million, respectively (2017 – $49 million and $150 million, respectively).

9. Common shares

TRANSCANADA CORPORATION ATM EQUITY PROGRAM

In the three months ended September 30, 2018, the Company issued 6.1 million common shares under the TransCanada ATM program at an average price of $57.75 per common share for proceeds of $351 million, net of related commissions and fees of approximately $3 million. In the nine months ended September 30, 2018, 20.0 million common shares have been issued at an average price of $56.13 per common share for proceeds of $1.1 billion, net of approximately $10 million of related commissions and fees.

In June 2018, the Company replenished the capacity available under its existing Corporate ATM program. This allows for the issuance of additional common shares from treasury for an aggregate gross sales price of up to $1.0 billion, for a revised total of $2.0 billion or its U.S. dollar equivalent. The Corporate ATM program, as amended, is effective to July 23, 2019.

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

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

three months ended September 30, 2018 (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	**(273)**	**(9)**	**(282)**
Change in fair value of net investment hedges	**12**	**(3)**	**9**
Change in fair value of cash flow hedges	**5**	**(1)**	**4**
Reclassification to net income of gains and losses on cash flow hedges	**8**	**(2)**	**6**
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**4**	**6**	**10**
Other comprehensive income on equity investments	**7**	**(1)**	**6**
Other comprehensive loss	**(237)**	**(10)**	**(247)**

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)

nine months ended September 30, 2018 (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	**397**	**12**	**409**
Change in fair value of net investment hedges	**(8)**	**2**	**(6)**
Change in fair value of cash flow hedges	**8**	**1**	**9**
Reclassification to net income of gains and losses on cash flow hedges	**21**	**(5)**	**16**
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**12**	**(2)**	**10**
Other comprehensive income on equity investments	**20**	**(2)**	**18**
Other comprehensive income	**450**	**6**	**456**

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)

The changes in AOCI by component are as follows:

three months ended September 30, 2018 (unaudited - millions of Canadian $)	**Currency Translation Adjustments**	**Cash Flow Hedges**	**Pension and OPEB Plan Adjustments**	**Equity Investments**	**Total**[1]
AOCI balance at July 1, 2018	**(462)**	**(26)**	**(203)**	**(443)**	**(1,134)**
Other comprehensive (loss)/income before reclassifications[2]	**(239)**	**3**	**—**	**—**	**(236)**
Amounts reclassified from AOCI[3]	**—**	**5**	**10**	**5**	**20**
Net current period other comprehensive (loss)/ income	**(239)**	**8**	**10**	**5**	**(216)**
AOCI balance at September 30, 2018	**(701)**	**(18)**	**(193)**	**(438)**	**(1,350)**

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 are net of non-controlling interest losses of $34 million and gains of $1 million, respectively.

3 Amounts reclassified from AOCI on cash flow hedges and equity investments are net of non-controlling interest gains of $1 million and $1 million, respectively.

nine months ended September 30, 2018 (unaudited - millions of Canadian $)	**Currency Translation Adjustments**	**Cash Flow Hedges**	**Pension and OPEB Plan Adjustments**	**Equity Investments**	**Total**[1]
AOCI balance at January 1, 2018	**(1,043)**	**(31)**	**(203)**	**(454)**	**(1,731)**
Other comprehensive income before reclassifications[2]	**342**	**1**	**—**	**—**	**343**
Amounts reclassified from AOCI[3,4]	**—**	**12**	**10**	**16**	**38**
Net current period other comprehensive income	**342**	**13**	**10**	**16**	**381**
AOCI balance at September 30, 2018	**(701)**	**(18)**	**(193)**	**(438)**	**(1,350)**

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

2 Other comprehensive income before reclassifications on currency translation adjustments and cash flow hedges are net of non-controlling interest gains of $61 million and $8 million, respectively.

3 Losses related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be $16 million ($11 million after tax) at September 30, 2018. 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.

4 Amounts reclassified from AOCI on cash flow hedges and equity investments are net of non-controlling interest gains of $4 million and $2 million, respectively.

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

	Amounts Reclassified From AOCI				
	three months ended September 30		nine months ended September 30		Affected line item in the Condensed consolidated statement of income
(unaudited - millions of Canadian $)	2018	2017	2018	2017	
Cash flow hedges					
Commodities	**(3)**	4	**(4)**	15	Revenues (Energy)
Interest	**(4)**	(4)	**(13)**	(13)	Interest expense
	(7)	—	**(17)**	2	Total before tax
	2	—	**5**	(1)	Income tax expense
	(5)	—	**(12)**	1	Net of tax[1,3]
Pension and other post-retirement benefit plan adjustments					
Amortization of actuarial gains and losses	**(4)**	(4)	**(12)**	(12)	Plant operating costs and other[2]
Settlement charge	**—**	(2)	**—**	(2)	Plant operating costs and other[2]
	(4)	(6)	**(12)**	(14)	Total before tax
	(6)	2	**2**	5	Income tax expense
	(10)	(4)	**(10)**	(9)	Net of tax[1]
Equity investments					
Equity income	**(6)**	(4)	**(19)**	(8)	Income from equity investments
	1	1	**3**	2	Income tax expense
	(5)	(3)	**(16)**	(6)	Net of tax[1,3]
Currency translation adjustments					
Realization of foreign currency translation gain on disposal of foreign operations	**—**	—	**—**	77	Gain on sales of assets
	—	—	**—**	—	Income tax expense
	—	—	**—**	77	Net of tax[1]

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

2 These AOCI components are included in the computation of net benefit cost. Refer to Note 11, Employee post-retirement benefits, for further information.

3 Amounts reclassified from AOCI on cash flow hedges and equity investments are net of non-controlling interest gains of $1 million and $1 million, respectively, for the three months ended September 30, 2018 (2017 – nil and nil) and $4 million and $2 million, respectively, for the nine months ended September 30, 2018 (2017 – nil and nil).

11. Employee post-retirement benefits

The net benefit cost recognized for the Company's pension benefit 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 $)	2018	2017	2018	2017	2018	2017	2018	2017
Service cost[1]	**30**	25	**1**	1	**91**	81	**3**	3
Other components of net benefit cost[1]								
Interest cost	**33**	30	**3**	3	**100**	92	**10**	10
Expected return on plan assets	**(55)**	(45)	**(4)**	(5)	**(165)**	(134)	**(12)**	(16)
Amortization of actuarial loss	**4**	3	**—**	1	**11**	11	**1**	1
Amortization of regulatory asset	**5**	26	**—**	—	**14**	33	**—**	1
Settlement charge	**—**	2	**—**	—	**—**	2	**—**	—
	(13)	16	**(1)**	(1)	**(40)**	4	**(1)**	(4)
Net Benefit Cost	**17**	41	**—**	—	**51**	85	**2**	(1)

1 Service cost and other components of net benefit cost are included in Plant operating costs and other in the Condensed consolidated statement of income.

12. 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, 2018, without taking into account security held, consisted of cash and cash equivalents, accounts receivable, available-for-sale assets, derivative assets and loans 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, 2018, 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.

The Company 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 its interest in the joint venture as an equity investment. In 2017, the Company entered into a MXN$21.3 billion unsecured revolving credit facility with the joint venture, which bears interest at a floating rate and matures in March 2022. Draws on the credit facility result in a loan receivable from the joint venture representing the Company's proportionate share of the debt financing requirements advanced to the joint venture.

At September 30, 2018, the balance of the Company's loan receivable from the joint venture totaled MXN$18.0 billion or $1.2 billion (December 31, 2017 – MXN$14.4 billion or $919 million) and Interest income and other included $32 million and $88 million of interest income on this loan receivable for the three and nine months ended September 30, 2018 (2017 – $11 million and $14 million). Amounts recognized in Interest income and other are offset by a corresponding proportionate share of interest 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 amounts for the derivatives designated as a net investment hedge were as follows:

	September 30, 2018		December 31, 2017	
(unaudited - millions of Canadian $, unless noted otherwise)	**Fair value[1,2]**	**Notional amount**	**Fair value[1,2]**	**Notional amount**
U.S. dollar cross-currency interest rate swaps (maturing 2018 to 2019)[3]	**(42)**	**US 300**	(199)	US 1,200
U.S. dollar foreign exchange options (maturing 2018 to 2019)	**(2)**	**US 2,000**	5	US 500
	(44)	**US 2,300**	(194)	US 1,700

1 Fair value equals carrying value.

2 No amounts have been excluded from the assessment of hedge effectiveness.

3 In the three and nine months ended September 30, 2018, Net income includes net realized gains of nil and $1 million, respectively (2017 – $1 million and $3 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, 2018	December 31, 2017
Notional amount	**28,300 (US 21,900)**	25,400 (US 20,200)
Fair value	**30,200 (US 23,300)**	28,900 (US 23,100)

FINANCIAL INSTRUMENTS

Non-derivative financial instruments

Fair value of non-derivative financial instruments

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. Each of these instruments are 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 are classified in Level II of the fair value hierarchy:

	September 30, 2018		December 31, 2017	
(unaudited - millions of Canadian $)	Carrying amount	Fair value	Carrying amount	Fair value
Long-term debt including current portion[1,2]	**(36,700)**	**(39,956)**	(34,741)	(40,180)
Junior subordinated notes	**(7,186)**	**(7,014)**	(7,007)	(7,233)
	(43,886)	**(46,970)**	(41,748)	(47,413)

1 Long-term debt is recorded at amortized cost except for US$700 million (December 31, 2017 – US$1.1 billion) that is attributed to hedged risk and recorded at fair value.

2 Net income for the three and nine months ended September 30, 2018 includes unrealized losses of $1 million and unrealized gains of $3 million, respectively, (2017 – gains of $1 million and $2 million, respectively) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$700 million of long-term debt at September 30, 2018 (December 31, 2017 – US$1.1 billion). 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:

	September 30, 2018		December 31, 2017	
(unaudited - millions of Canadian $)	LMCI restricted investments	Other restricted investments[1]	LMCI restricted investments	Other restricted investments[1]
Fair values of fixed income securities[2]				
Maturing within 1 year	**—**	**19**	—	23
Maturing within 1-5 years	**—**	**113**	—	107
Maturing within 5-10 years	**84**	**—**	14	—
Maturing after 10 years	**894**	**—**	790	—
	978	**132**	804	130

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

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

	September 30, 2018		September 30, 2017	
(unaudited - millions of Canadian $)	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	**(34)**	**—**	(38)	—
nine months ended	**(29)**	**1**	(23)	—
Net realized losses in the period				
three months ended	**—**	**—**	—	—
nine months ended	**(3)**	**—**	(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 Gains and losses on other restricted investments are included in Interest income and other.

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 derivative instruments is as follows:

at September 30, 2018 (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]	**1**	**—**	**—**	**332**	**333**
Foreign exchange	**—**	**—**	**13**	**20**	**33**
Interest rate	**6**	**—**	**—**	**—**	**6**
	7	**—**	**13**	**352**	**372**
Intangible and other assets					
Commodities[2]	**—**	**—**	**—**	**66**	**66**
Foreign exchange	**—**	**—**	**—**	**—**	**—**
Interest rate	**17**	**—**	**—**	**—**	**17**
	17	**—**	**—**	**66**	**83**
Total Derivative Assets	**24**	**—**	**13**	**418**	**455**
Accounts payable and other					
Commodities[2]	**(4)**	**—**	**—**	**(313)**	**(317)**
Foreign exchange	**—**	**—**	**(57)**	**(39)**	**(96)**
Interest rate	**—**	**(5)**	**—**	**—**	**(5)**
	(4)	**(5)**	**(57)**	**(352)**	**(418)**
Other long-term liabilities					
Commodities[2]	**(1)**	**—**	**—**	**(40)**	**(41)**
Foreign exchange	**—**	**—**	**—**	**—**	**—**
Interest rate	**—**	**(2)**	**—**	**—**	**(2)**
	(1)	**(2)**	**—**	**(40)**	**(43)**
Total Derivative Liabilities	**(5)**	**(7)**	**(57)**	**(392)**	**(461)**
Total Derivatives	**19**	**(7)**	**(44)**	**26**	**(6)**

1 Fair value equals carrying value.

2 Includes purchases and sales of power, natural gas and liquids.

at December 31, 2017 (unaudited - millions of Canadian $)	**Cash Flow Hedges**	**Fair Value Hedges**	**Net Investment Hedges**	**Held for Trading**	**Total Fair Value of Derivative Instruments**[1]
Other current assets					
Commodities[2]	1	—	—	249	250
Foreign exchange	—	—	8	70	78
Interest rate	3	—	—	1	4
	4	—	8	320	332
Intangible and other assets					
Commodities[2]	—	—	—	69	69
Interest rate	4	—	—	—	4
	4	—	—	69	73
Total Derivative Assets	8	—	8	389	405
Accounts payable and other					
Commodities[2]	(6)	—	—	(208)	(214)
Foreign exchange	—	—	(159)	(10)	(169)
Interest rate	—	(4)	—	—	(4)
	(6)	(4)	(159)	(218)	(387)
Other long-term liabilities					
Commodities[2]	(2)	—	—	(26)	(28)
Foreign exchange	—	—	(43)	—	(43)
Interest rate	—	(1)	—	—	(1)
	(2)	(1)	(43)	(26)	(72)
Total Derivative Liabilities	(8)	(5)	(202)	(244)	(459)
Total Derivatives	—	(5)	(194)	145	(54)

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.

Derivatives in fair value hedging relationships

The following table details amounts recorded on the Condensed consolidated balance sheet in relation to cumulative adjustments for fair value hedges included in the carrying amount of the hedged liabilities:

	Carrying amount		**Fair value hedging adjustments**[1]	
(unaudited - millions of Canadian $)	**September 30, 2018**	**December 31, 2017**	**September 30, 2018**	**December 31, 2017**
Current portion of long-term debt	**(387)**	(688)	**1**	1
Long-term debt	**(511)**	(685)	**6**	4
	(898)	(1,373)	**7**	5

1 At September 30, 2018 and December 31, 2017, adjustments for discontinued hedging relationships included in these balances were nil.

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, 2018 (unaudited)	**Power**	**Natural Gas**	**Liquids**	**Foreign Exchange**	**Interest Rate**
Purchases[1]	**30,533**	**61**	**55**	**—**	**—**
Sales[1]	**22,711**	**70**	**74**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**3,898**	**1,200**
Maturity dates	**2018-2022**	**2018-2021**	**2018-2019**	**2018-2019**	**2018-2028**

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

at December 31, 2017 (unaudited)	**Power**	**Natural Gas**	**Liquids**	**Foreign Exchange**	**Interest Rate**
Purchases[1]	66,132	133	6	—	—
Sales[1]	42,836	135	7	—	—
Millions of U.S. dollars	—	—	—	2,931	2,300
Millions of Mexican pesos	—	—	—	100	—
Maturity dates	2018-2022	2018-2021	2018	2018	2018-2022

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

Unrealized and realized (losses)/gains 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 $)	**2018**	**2017**	**2018**	**2017**
Derivative Instruments Held for Trading[1]				
Amount of unrealized (losses)/gains in the period				
Commodities[2]	**(31)**	45	**(41)**	(102)
Foreign exchange	**60**	33	**(79)**	89
Interest rate	**—**	(1)	**—**	(1)
Amount of realized gains/(losses) in the period				
Commodities	**81**	(82)	**210**	(167)
Foreign exchange	**(5)**	19	**14**	10
Interest rate	**—**	1	**—**	1
Derivative Instruments in Hedging Relationships				
Amount of realized gains/(losses) in the period				
Commodities	**1**	4	**—**	17
Foreign exchange	**—**	—	**—**	5
Interest rate	**(2)**	—	**(1)**	1

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

2 In the three and nine months ended September 30, 2018 and 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.

Derivatives in cash flow hedging relationships

The components of OCI related to the change in fair value of 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 $)	**2018**	2017	**2018**	2017
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]				
Commodities	**3**	2	**(3)**	5
Interest rate	**2**	(1)	**11**	—
	5	1	**8**	5

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

Effect of fair value and cash flow hedging relationships

The following tables detail amounts presented on the Condensed consolidated statement of income in which the effects of fair value or cash flow hedging relationships are recorded.

	three months ended September 30			
	Revenues (Energy)		Interest Expense	
(unaudited - millions of Canadian $)	**2018**	2017	**2018**	2017
Total Amount Presented in the Condensed Consolidated Statement of Income	**535**	887	**(577)**	(504)
Fair Value Hedges				
Interest rate contracts				
Hedged items	**—**	—	**(17)**	(18)
Derivatives designated as hedging instruments	**—**	—	**(2)**	(1)
Cash Flow Hedges				
Reclassification of gains/(losses) on derivative instruments from AOCI to net income				
Interest rate contracts[1]	**—**	—	**5**	4
Commodity contracts[2]	**3**	(4)	**—**	—

1 Refer to Note 10, Other comprehensive (loss)/income and accumulated other comprehensive loss, for the components of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests.

2 There are no amounts recognized in earnings that were excluded from effectiveness testing.

	nine months ended September 30			
	Revenues (Energy)		Interest Expense	
(unaudited - millions of Canadian $)	2018	2017	2018	2017
Total Amount Presented in the Condensed Consolidated Statement of Income	**1,724**	2,581	**(1,662)**	(1,528)
Fair Value Hedges				
Interest rate contracts				
Hedged items	**—**	—	**(59)**	(56)
Derivatives designated as hedging instruments	**—**	—	**(4)**	1
Cash Flow Hedges				
Reclassification of gains/(losses) on derivative instruments from AOCI to net income				
Interest rate contracts[1]	**—**	—	**17**	13
Commodity contracts[2]	**4**	(15)	**—**	—

1 Refer to Note 10, Other comprehensive (loss)/income and accumulated other comprehensive loss, for the components of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests.

2 There are no amounts recognized in earnings that were excluded from effectiveness testing.

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 on the Condensed consolidated balance sheet had the Company elected to present these contracts on a net basis:

at September 30, 2018 (unaudited - millions of Canadian $)	Gross derivative instruments	Amounts available for offset[1]	Net amounts
Derivative instrument assets			
Commodities	**399**	**(309)**	**90**
Foreign exchange	**33**	**(24)**	**9**
Interest rate	**23**	**—**	**23**
	455	**(333)**	**122**
Derivative instrument liabilities			
Commodities	**(358)**	**309**	**(49)**
Foreign exchange	**(96)**	**24**	**(72)**
Interest rate	**(7)**	**—**	**(7)**
	(461)	**333**	**(128)**

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

at December 31, 2017 (unaudited - millions of Canadian $)	Gross derivative instruments	Amounts available for offset[1]	Net amounts
Derivative instrument assets			
Commodities	319	(198)	121
Foreign exchange	78	(56)	22
Interest rate	8	(1)	7
	405	(255)	150
Derivative instrument liabilities			
Commodities	(242)	198	(44)
Foreign exchange	(212)	56	(156)
Interest rate	(5)	1	(4)
	(459)	255	(204)

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

With respect to the derivative instruments presented above, the Company provided cash collateral of $87 million and letters of credit of $17 million as at September 30, 2018 (December 31, 2017 – $165 million and $30 million) to its counterparties. At September 30, 2018, the Company held nil in cash collateral and $1 million in letters of credit (December 31, 2017 – nil and $3 million) from counterparties on asset exposures.

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. The Company may also need to provide collateral if the fair value of its derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at September 30, 2018, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $2 million (December 31, 2017 – $2 million), for which the Company did not provide collateral in the normal course of business at September 30, 2018 or December 31, 2017. If the credit-risk-related contingent features in these agreements were triggered on September 30, 2018, the Company would have been required to provide collateral of $2 million (December 31, 2017 – $2 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. An active market is a market in which frequency and volume of transactions provides pricing information on an ongoing basis.
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 are categorized as follows:

at September 30, 2018 (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	**217**	**145**	**37**	**399**
Foreign exchange	**—**	**33**	**—**	**33**
Interest rate	**—**	**23**	**—**	**23**
Derivative instrument liabilities				
Commodities	**(220)**	**(87)**	**(51)**	**(358)**
Foreign exchange	**—**	**(96)**	**—**	**(96)**
Interest rate	**—**	**(7)**	**—**	**(7)**
	(3)	**11**	**(14)**	**(6)**

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, 2018.

at December 31, 2017 (unaudited - millions of Canadian $)	Quoted prices in active markets (Level I)[1]	Significant other observable inputs (Level II)[1]	Significant unobservable inputs (Level III)[1]	Total
Derivative instrument assets				
Commodities	21	283	15	319
Foreign exchange	—	78	—	78
Interest rate	—	8	—	8
Derivative instrument liabilities				
Commodities	(27)	(193)	(22)	(242)
Foreign exchange	—	(212)	—	(212)
Interest rate	—	(5)	—	(5)
	(6)	(41)	(7)	(54)

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2017.

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 $)	**2018**	2017	**2018**	2017
Balance at beginning of period	**40**	9	**(7)**	16
Total losses included in Net income	**(24)**	(10)	**(6)**	(12)
Settlements	**(14)**	(1)	**9**	4
Sales	**—**	—	**—**	(5)
Transfers out of Level III	**(16)**	—	**(10)**	(5)
Balance at end of period[1]	**(14)**	(2)	**(14)**	(2)

1 For the three and nine months ended September 30, 2018, Revenues include unrealized losses of $16 million and $2 million, respectively, attributed to derivatives in the Level III category that were still held at September 30, 2018 (2017 – unrealized losses of $10 million and $14 million, respectively).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $27 million decrease or increase, respectively, in the fair value of outstanding derivative instruments included in Level III as at September 30, 2018.

13. Contingencies and guarantees

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.

GUARANTEES

TransCanada and its joint venture 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 on the Condensed consolidated balance sheet. Information regarding the Company's guarantees is as follows:

		at September 30, 2018		at December 31, 2017	
(unaudited - millions of Canadian $)	Term	Potential exposure[1]	Carrying value	Potential exposure[1]	Carrying value
Sur de Texas	ranging to 2020	**187**	**1**	315	2
Bruce Power	ranging to 2019	**88**	**—**	88	1
Other jointly-owned entities	ranging to 2059	**104**	**11**	104	13
		379	**12**	507	16

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

14. Variable interest entities

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 is the primary beneficiary. As the primary beneficiary, 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 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, 2018	December 31, 2017
ASSETS		
Current Assets		
Cash and cash equivalents	**62**	41
Accounts receivable	**59**	63
Inventories	**22**	23
Other	**13**	11
	156	138
Plant, Property and Equipment	**3,576**	3,535
Equity Investments	**925**	917
Goodwill	**505**	490
Intangible and Other Assets	**17**	3
	5,179	5,083
LIABILITIES		
Current Liabilities		
Accounts payable and other	**79**	137
Dividends payable	**—**	1
Accrued interest	**30**	23
Current portion of long-term debt	**74**	88
	183	249
Regulatory Liabilities	**39**	34
Other Long-Term Liabilities	**2**	3
Deferred Income Tax Liabilities	**13**	13
Long-Term Debt	**3,152**	3,244
	3,389	3,543

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, 2018	December 31, 2017
Balance sheet		
Equity investments	**4,430**	4,372
Off-balance sheet		
Potential exposure to guarantees	**171**	171
Maximum exposure to loss	**4,601**	4,543

15. Subsequent Events

Long-term debt issuance

On October 12, 2018, TCPL issued US$1.0 billion of Senior Unsecured Notes, due in March 2049, bearing interest at a fixed rate of 5.10 per cent and US$400 million of Senior Unsecured Notes, due in May 2028, bearing interest at a fixed rate of 4.25 per cent.

Reimbursement of Coastal GasLink pipeline pre-development costs

In accordance with provisions in the agreements with the LNG Canada joint venture participants, to date, four parties have elected to reimburse TransCanada for their share of pre-development costs on the Coastal GasLink (CGL) pipeline project, totalling $399 million of cost reimbursement, with payments due by November 30, 2018. At September 30, 2018, pre-development costs for the CGL pipeline were included in Intangible and other assets on the Company's Condensed consolidated balance sheet.