

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.

THIRD QUARTER 2018

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).

THIRD QUARTER 2018

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.

THIRD QUARTER 2018

Consolidated results - third quarter 2018

(unaudited - millions of \$, except per share amounts)	three months ended September 30		nine months ended September 30	
	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

THIRD QUARTER 2018

- 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

(unaudited - millions of \$, except per share amounts)	three months ended September 30		nine months ended September 30	
	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 (unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	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

THIRD QUARTER 2018

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

THIRD QUARTER 2018

- 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.

THIRD QUARTER 2018

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.

THIRD QUARTER 2018

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.

THIRD QUARTER 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.

THIRD QUARTER 2018

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).

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	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

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	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.

THIRD QUARTER 2018

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.

THIRD QUARTER 2018

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).

(unaudited - millions of US\$, unless noted otherwise)	three months ended September 30		nine months ended September 30	
	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.

THIRD QUARTER 2018

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.

THIRD QUARTER 2018

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).

(unaudited - millions of US\$, unless noted otherwise)	three months ended September 30		nine months ended September 30	
	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.

THIRD QUARTER 2018

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).

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	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.

THIRD QUARTER 2018

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).

(unaudited - millions of Canadian \$, unless noted otherwise)	three months ended September 30		nine months ended September 30	
	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 (unaudited - millions of \$, pre-tax)	three months ended September 30		nine months ended September 30	
	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)

THIRD QUARTER 2018

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.

(unaudited - millions of \$, unless noted otherwise)	three months ended September 30		nine months ended September 30	
	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 EBIT¹	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.

THIRD QUARTER 2018

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		nine months ended September 30	
	2018	2017	2018	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		nine months ended September 30	
	2018	2017	2018	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

THIRD QUARTER 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

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	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

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	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.

THIRD QUARTER 2018

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

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	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

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	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.

THIRD QUARTER 2018

Preferred share dividends

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	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.

THIRD QUARTER 2018

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.

THIRD QUARTER 2018

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.

THIRD QUARTER 2018

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.

THIRD 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

(unaudited - millions of \$, except per share amounts)	three months ended September 30		nine months ended September 30	
	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 operations¹	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 flow¹	1,413	1,170	4,158	3,691
Comparable distributable cash flow per common share¹	\$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.

THIRD QUARTER 2018

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

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	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.

THIRD QUARTER 2018

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

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	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.

THIRD QUARTER 2018

LONG-TERM DEBT REPAYED

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.

THIRD QUARTER 2018

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

THIRD QUARTER 2018

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.

THIRD QUARTER 2018

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

(unaudited - millions of US \$)	three months ended September 30		nine months ended September 30	
	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.

THIRD QUARTER 2018

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:

(unaudited - millions of Canadian \$, unless noted otherwise)	September 30, 2018		December 31, 2017	
	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.

THIRD QUARTER 2018

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.

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2018	2017	2018	2017
Derivative instruments held for trading¹				
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.

THIRD QUARTER 2018

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:

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	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 income¹				
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.

THIRD QUARTER 2018

Reconciliation of non-GAAP measures

(unaudited - millions of \$)	three months ended September 30		nine months ended September 30	
	2018	2017	2018	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		nine months ended September 30	
	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
Total unrealized (losses)/gains from risk management activities	(34)	45	(44)	(102)

THIRD QUARTER 2018

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.

THIRD QUARTER 2018

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.

THIRD QUARTER 2018

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.