Quarterly report to shareholders

Second quarter 2018

Financial highlights

(unaudited - millions of $)	three months ended June 30		six months ended June 30	
	2018	**2017**	**2018**	**2017**
Income				
Revenues	**3,195**	3,230	**6,619**	6,637
Net income attributable to controlling interests and to common shares	**806**	909	**1,565**	1,581
Comparable EBITDA[1]	**1,991**	1,830	**4,054**	3,807
Comparable earnings[1]	**789**	687	**1,678**	1,414
Cash flows				
Net cash provided by operations	**1,779**	1,340	**3,171**	2,621
Comparable funds generated from operations[1]	**1,432**	1,351	**3,022**	2,843
Comparable distributable cash flow[1]	**1,318**	1,203	**2,775**	2,566
Capital spending[2]	**2,597**	2,321	**4,693**	4,115
Basic common shares outstanding (millions)				
– weighted average for the period	**878**	865	**876**	863
– issued and outstanding at end of period	**879**	865	**879**	865

1 Comparable EBITDA, comparable earnings, comparable funds generated from operations and comparable distributable cash flow 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

August 1, 2018

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TransCanada PipeLines Limited (TCPL or the Company). It discusses our business, operations, financial position, risks and other factors for the three and six months ended June 30, 2018, and should be read with the accompanying unaudited condensed consolidated financial statements for the three and six months ended June 30, 2018, which have been prepared in accordance with U.S. GAAP.

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

FORWARD-LOOKING INFORMATION

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

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

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

- planned changes in our business
- our financial and operational performance, including the performance of our subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows and future financing options available to us
- expected dividend growth
- expected costs for planned projects, including projects under construction, permitting and in development
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes, including the expected impact of the 2018 FERC Actions
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- expected capital expenditures and contractual obligations
- expected operating and financial results
- expected impact of future accounting changes, commitments and contingent liabilities
- expected impact of U.S. Tax Reform
- expected industry, market and economic conditions.

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

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

Assumptions

- continued wind-down of our U.S. Northeast power marketing business
- inflation rates and commodity prices
- nature and scope of hedging activities
- regulatory decisions and outcomes, including those related to the 2018 FERC Actions
- interest, tax and foreign exchange rates, including the impact of U.S. Tax Reform
- planned and unplanned outages and the use of our pipeline and energy assets
- integrity and reliability of our assets
- access to capital markets
- anticipated construction costs, schedules and completion dates.

Risks and uncertainties

- our ability to successfully implement our strategic priorities and whether they will yield the expected benefits
- the operating performance of our pipeline and energy assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the availability and price of energy commodities
- the amount of capacity payments and revenues from our energy business
- regulatory decisions and outcomes, including those related to the 2018 FERC Actions
- outcomes of legal proceedings, including arbitration and insurance claims
- performance and credit risk of our counterparties
- changes in market commodity prices
- changes in the regulatory environment
- changes in the political environment
- changes in environmental and other laws and regulations
- competitive factors in the pipeline and energy sectors
- construction and completion of capital projects
- costs for labour, equipment and materials
- access to capital markets, including the economic benefit of asset drop downs to TC PipeLines, LP
- 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 TCPL in our Annual Information Form and other disclosure documents, which are available on SEDAR (www.sedar.com).

NON-GAAP MEASURES

This MD&A references the following non-GAAP measures:

- comparable earnings
- comparable EBITDA
- comparable EBIT
- funds generated from operations
- comparable funds generated from operations
- comparable distributable cash flow.

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 equivalent GAAP measures.

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

Comparable earnings

Comparable earnings represents earnings or loss attributable to our common shareholder 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 controlling interests and to common shares.

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 measure of our performance and an effective tool for evaluating trends in each segment. Comparable EBITDA is calculated the same way as comparable EBIT but excludes the non-cash charges for depreciation and amortization. See the Reconciliation of non-GAAP measures section for a reconciliation to segmented earnings.

Funds generated from operations and comparable funds generated from operations

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

Comparable distributable cash flow

We believe comparable distributable cash flow is a useful supplemental measure of performance that defines cash available to our common shareholder before capital allocation. Comparable distributable cash flow is defined as comparable funds generated from operations less 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, beginning in second quarter 2018, our presentation of comparable distributable cash flow only includes a reduction for non-recoverable maintenance capital expenditures in its calculation. Comparative figures have been adjusted to reflect this presentation.

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

Consolidated results - second quarter 2018

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Canadian Natural Gas Pipelines	**280**	305	**533**	587
U.S. Natural Gas Pipelines	**541**	401	**1,189**	962
Mexico Natural Gas Pipelines	**118**	120	**255**	238
Liquids Pipelines	**390**	251	**731**	478
Energy	**191**	645	**241**	843
Corporate	**72**	(40)	**(9)**	(73)
Total segmented earnings	**1,592**	1,682	**2,940**	3,035
Interest expense	**(584)**	(540)	**(1,132)**	(1,056)
Allowance for funds used during construction	**113**	121	**218**	222
Interest income and other	**(93)**	89	**(30)**	109
Income before income taxes	**1,028**	1,352	**1,996**	2,310
Income tax expense	**(146)**	(388)	**(261)**	(584)
Net income	**882**	964	**1,735**	1,726
Net income attributable to non-controlling interests	**(76)**	(55)	**(170)**	(145)
Net income attributable to controlling interests and to common shares	**806**	909	**1,565**	1,581

Net income attributable to controlling interests and to common shares decreased by $103 million and $16 million for the three and six months ended June 30, 2018 compared to the same periods in 2017.

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:

- an after-tax loss of $5 million year-to-date related to our U.S. Northeast power marketing contracts which included an after-tax loss of $11 million in second quarter and an after-tax gain of $6 million in first quarter primarily due to income recognized 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 will continue to run-off through to mid-2020.

2017 results included:

- a $255 million after-tax net gain related to the monetization of our U.S. Northeast power business, which included a $441 million after-tax gain on the sale of TC Hydro in second quarter, an incremental loss of $176 million after tax recorded in second quarter on the sale of the thermal and wind package and $10 million year-to-date of after-tax disposition costs

- an after-tax charge of $15 million in second quarter and $39 million year-to-date for integration-related costs associated with the acquisition of Columbia
- an after-tax charge of $4 million in second quarter and $11 million year-to-date related to the maintenance of Keystone XL assets which 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 controlling interests and to common shares to comparable earnings is shown in the following table.

RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Net income attributable to controlling interests and to common shares	**806**	909	**1,565**	1,581
Specific items (net of tax):				
U.S. Northeast power marketing contracts	**11**	—	**5**	—
Net gain on sales of U.S. Northeast power generation assets	**—**	(265)	**—**	(255)
Integration and acquisition related costs – Columbia	**—**	15	**—**	39
Keystone XL asset costs	**—**	4	**—**	11
Keystone XL income tax recoveries	**—**	—	**—**	(7)
Risk management activities[1]	**(28)**	24	**108**	45
Comparable earnings	**789**	687	**1,678**	1,414

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Risk management activities	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Canadian Power	**1**	3	**3**	4
U.S. Power	**39**	(94)	**(62)**	(156)
Liquids marketing	**62**	4	**55**	4
Natural Gas Storage	**(3)**	(4)	**(6)**	1
Foreign exchange	**(60)**	41	**(139)**	56
Income tax attributable to risk management activities	**(11)**	26	**41**	46
Total unrealized gains/(losses) from risk management activities	**28**	(24)	**(108)**	(45)

Comparable earnings increased by $102 million for the three months ended June 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, higher volumes on the Keystone Pipeline System and increased earnings from liquids marketing activities
- lower income tax expense primarily due to lower income tax rates as a result of U.S. Tax Reform

- 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 U.S. Power mainly due to the sale of the U.S. Northeast power generation assets in second quarter 2017
- lower earnings from Bruce Power primarily due to lower volumes resulting from increased outage days
- lower Eastern Power results mainly due to the sale of our Ontario solar assets in December 2017.

Comparable earnings increased by $264 million for the six months ended June 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, higher volumes on the Keystone Pipeline System and increased earnings from liquids marketing activities
- lower income tax expense primarily due to lower income tax rates as a result of U.S. Tax Reform
- higher interest income and other primarily resulting from realized gains in 2018 compared to realized losses in 2017 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- lower earnings from U.S. Power mainly due to the sale of the U.S. Northeast power generation assets in second quarter 2017
- 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
- lower Eastern Power results mainly due to the sale of our Ontario solar assets in December 2017.

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, H.R. 1, the Tax Cuts and Jobs Act (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, deferred income tax assets and deferred income tax 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, 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 interstate pipelines 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 pipeline's return on equity (ROE) assuming a single-issue adjustment to a pipeline's rates; and (3) a NOI seeking comment on how FERC should address changes related to accumulated deferred income taxes and bonus depreciation. On July 18, 2018, FERC issued (1) an Order on Rehearing of the Revised Policy Statement dismissing rehearing requests; and (2) a Final Rule adopting and revising procedures from, and clarifying aspects of, the NOPR (collectively, the "2018 FERC Actions"). The Final Rule will become effective September 13, 2018, and is subject to requests for further rehearing and clarification. Each is described below.

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 accumulated deferred income taxes 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 accumulated deferred income tax 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

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 No. 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. Pipelines filing the FERC Form No. 501-G will have four options:

- make a limited Natural Gas Act Section 4 filing to reduce its rates by the reduction in its cost-of-service shown in its FERC Form No. 501-G. For any pipeline electing this option, FERC guarantees a three-year moratorium on Natural Gas Act 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 accumulated deferred income tax balance used for rate-making purposes. In situations where the accumulated deferred income tax 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.

We are evaluating this Final Rule and our next courses of action, however, we do not expect an immediate or a retroactive impact from the Final Rule or the Revised Policy Statement described above.

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 accumulated deferred income taxes 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 accumulated deferred income taxes for MLP pipelines, finding that if an MLP pipeline's income tax allowance is eliminated from its cost-of-service rates, then its existing accumulated deferred income tax balance used for rate-making purposes should also be eliminated from its rate base.

IMPACT OF 2018 FERC ACTIONS ON TCPL

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 they are held through wholly-owned taxable corporations and, in addition, a significant proportion of their 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, some of which may be accelerated by the Final Rule, 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 wholly-owned U.S. natural gas pipelines is expected to be limited in comparison to pre-U.S. Tax Reform.

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

At the time and as a result 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 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 portfolio management, cash on hand and substantial committed credit facilities.

Impact of 2018 FERC Actions on TC PipeLines, LP

We are analyzing the impact of the 2018 FERC Actions on our TC PipeLines, LP assets, particularly considering the changes noted above and alternatives now available under the Final Rule. While a number of uncertainties exist with respect to the changes, TC PipeLines, LP's earnings, cash flows and financial position could be materially adversely impacted. Should we or TC PipeLines, LP choose to proactively address the issues contemplated by the 2018 FERC Actions, prospective changes in certain pipeline systems' rates could occur as early as late 2018. However, the impact in 2018 is expected to be limited, while subsequent periods for TC PipeLines, LP 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. 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 our consolidated earnings or cash flow.

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 accumulated deferred income tax liability from rate base, thus increasing rate base in general, may further mitigate the loss of the tax allowance in cost-of-service based rates.

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

Impairment Considerations

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

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

Until the 2018 FERC Actions are implemented through individual rate proceedings or settlements and we and TC PipeLines, LP have fully evaluated our respective alternatives to minimize any negative impact, we believe that it is not more likely than not that the fair value of any of the reporting units is less than its respective carrying value. Therefore, a goodwill impairment test has not been performed in 2018 to date. We also determined there is no indication that the carrying values of plant, property and equipment and equity investments potentially impacted by the 2018 FERC Actions are not recoverable. We will continue to monitor developments and assess our goodwill for impairment as well as review our property, plant and equipment and equity investments for recoverability as new information becomes available.

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 2018 FERC Actions, once finalized, could result in a goodwill impairment charge. The goodwill balance for Great Lakes is US$573 million at June 30, 2018 (December 31, 2017 - US$573 million). There is also a risk that the goodwill balance of US$82 million at June 30, 2018 (December 31, 2017 - US$82 million) related to Tuscarora could be negatively impacted by the 2018 FERC Actions.

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 rate-regulated accounting (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 regulatory, tax and accounting authorities as well as through our elections of specific treatments allowed under the Final Rule described above. Should additional guidance be provided by these authorities or other sources during the one-year measurement period permitted by the SEC, we will review the provisional amounts and adjust as appropriate. Other than the amortizations discussed below and the foreign exchange impacts, no adjustments were made to these amounts during second quarter 2018. Once the final impact of the 2018 FERC Actions is determined there may be prospective adjustments to our net regulatory liabilities.

Commencing January 1, 2018, we have amortized the net regulatory liabilities using the Reverse South Georgia methodology. Under this methodology, rate-regulated entities determine amortization based on their composite depreciation rate and immediately begin recording amortization. For the three and six months ended June 30, 2018, amortization of the net regulatory liabilities in the amount of $15 million and $24 million, respectively, was recorded and included in Revenues.

Capital Program

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

Our capital program consists of approximately $28 billion of near-term investments and approximately $24 billion of commercially-supported medium to longer-term projects. Amounts presented exclude capitalized interest and AFUDC.

Beginning in second quarter 2018, we have included three years of maintenance capital expenditures for all of our businesses in the following 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 market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits.

Near-term projects

(unaudited - billions of $)	Expected in-service date	Estimated project cost[1]	Carrying value at June 30, 2018
Canadian Natural Gas Pipelines			
Canadian Mainline	2018-2021	0.2	—
NGTL System	2018	0.6	0.4
	2019	2.6	0.5
	2020	1.7	0.1
	2021+	2.5	—
Regulated maintenance capital expenditures	2018-2020	2.5	0.2
U.S. Natural Gas Pipelines			
Columbia Gas			
Mountaineer XPress	2018	US 3.0	US 1.4
WB XPress	2018	US 0.9	US 0.6
Modernization II	2018-2020	US 1.1	US 0.3
Buckeye XPress	2020	US 0.2	—
Columbia Gulf			
Gulf XPress	2018	US 0.6	US 0.4
Other	2018-2020	US 0.3	US 0.1
Regulated maintenance capital expenditures	2018-2020	US 1.9	US 0.2
Mexico Natural Gas Pipelines			
Sur de Texas	2018	US 1.3	US 1.2
Villa de Reyes	2019	US 0.8	US 0.6
Tula	2020	US 0.7	US 0.5
Liquids Pipelines			
White Spruce	2019	0.2	0.1
Recoverable maintenance capital expenditures	2018-2020	0.1	—
Energy			
Napanee[2]	2018	1.5	1.3
Bruce Power – life extension[3]	up to 2020	0.9	0.3
Other			
Non-recoverable maintenance capital expenditures[4]	2018-2020	0.7	0.1
		24.3	**8.3**
Foreign exchange impact on near-term projects[5]		**3.3**	**1.6**
Total near-term projects (Cdn$)		**27.6**	**9.9**

1 Amounts reflect our proportionate share of joint venture costs where applicable and 100% of costs related to wholly-owned assets and assets held through TC PipeLines, LP.

2 Reflects increased costs required to bring facility into service in fourth quarter 2018.

3 Reflects our proportionate share of the remaining capital costs that Bruce Power expects to incur on its life extension investment programs in advance of the Unit 6 major refurbishment outage which is expected to begin in 2020.

4 Includes non-recoverable maintenance capital expenditures from all segments and is primarily comprised of Bruce Power cash calls and other Energy amounts.

5 Reflects U.S./Canada foreign exchange rate of 1.31 at June 30, 2018.

Medium to longer-term projects

The medium to longer-term projects have greater uncertainty with respect to timing and estimated project costs. The expected in-service dates of these projects are post-2020, and costs provided in the schedule below reflect the most recent costs for each project as filed with the various regulatory authorities or otherwise determined. These projects are subject to approvals that include FID and/or complex regulatory processes, however, each project has commercial support except where noted.

(unaudited - billions of $)	Estimated project cost[1]	Carrying value at June 30, 2018
Canadian Natural Gas Pipelines		
Canadian west coast LNG-related projects		
Coastal GasLink[2]	4.8	0.5
NGTL System – Merrick	1.9	—
Liquids Pipelines		
Heartland and TC Terminals[2,3]	0.9	0.1
Grand Rapids Phase 2	0.7	—
Keystone XL[4]	US 8.0	US 0.3
Keystone Hardisty Terminal[2,3,4]	0.3	0.1
Energy		
Bruce Power – life extension	5.3	—
	21.9	1.0
Foreign exchange impact on medium to longer-term projects[5]	2.5	0.1
Total medium to longer-term projects (Cdn$)	**24.4**	**1.1**

1 Amounts reflect our proportionate share of joint venture costs where applicable and 100% of costs related to wholly-owned assets and assets held through TC PipeLines, LP.

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 U.S./Canada foreign exchange rate of 1.31 at June 30, 2018.

Outlook

Consolidated comparable earnings

We expect consolidated comparable earnings for the second half of 2018 to be similar to the results achieved in the first half of the year. Our overall comparable earnings outlook for 2018 has increased compared to what was included in the 2017 Annual Report primarily due to:

- improved earnings from additional contract sales and lower expenses 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.

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 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 near-term capital program in 2018, as well as the capitalization of costs to further advance our medium to longer-term projects.

Canadian Natural Gas Pipelines

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
NGTL System	**311**	236	**582**	466
Canadian Mainline	**204**	264	**397**	511
Other[1]	**30**	27	**60**	54
Comparable EBITDA	**545**	527	**1,039**	1,031
Depreciation and amortization	**(265)**	(222)	**(506)**	(444)
Comparable EBIT and segmented earnings	**280**	305	**533**	587

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

Canadian Natural Gas Pipelines segmented earnings decreased by $25 million and $54 million for the three and six months ended June 30, 2018 compared to the same periods in 2017 and are equivalent to comparable EBIT.

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

NET INCOME AND AVERAGE INVESTMENT BASE

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Net Income				
NGTL System	**96**	87	**188**	169
Canadian Mainline	**44**	48	**81**	100
Average investment base				
NGTL System			**9,250**	8,043
Canadian Mainline			**3,829**	4,131

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

Net income for the Canadian Mainline decreased by $4 million and $19 million for the three and six months ended June 30, 2018 compared to the same periods in 2017 primarily because no incentive earnings have been recorded in 2018 pending an NEB decision on the 2018 - 2020 Tolls Review. As a result, 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 $43 million and $62 million for the three and six months ended June 30, 2018 compared to the same periods in 2017 mainly due to facilities that were placed in service for the NGTL System and an increase in the approved depreciation rates in the 2018-2019 Settlement.

U.S. Natural Gas Pipelines

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of US$, unless noted otherwise)	**2018**	**2017**	**2018**	**2017**
Columbia Gas	**202**	136	**433**	321
ANR	**118**	93	**259**	215
TC PipeLines, LP[1,2,3]	**33**	27	**72**	59
Great Lakes[4]	**21**	13	**56**	40
Midstream	**29**	20	**59**	43
Columbia Gulf	**30**	21	**56**	39
Other U.S. pipelines[3,5]	**16**	22	**31**	50
Non-controlling interests[6]	**97**	78	**215**	186
Comparable EBITDA	**546**	410	**1,181**	953
Depreciation and amortization	**(128)**	(112)	**(250)**	(224)
Comparable EBIT	**418**	298	**931**	729
Foreign exchange impact	**123**	103	**258**	243
Comparable EBIT (Cdn$)	**541**	401	**1,189**	972
Specific items:				
Integration and acquisition related costs – Columbia	**—**	—	**—**	(10)
Segmented earnings (Cdn$)	**541**	401	**1,189**	962

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 June 30, 2018, our ownership interest in TC PipeLines, LP was 25.5 per cent compared to 26.3 per cent for the same period in 2017. Our ownership interest for the six months ended June 30, 2018 ranged from 25.7 to 25.5 per cent compared to a range of 26.5 to 26.3 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 $140 million and $227 million for the three and six months ended June 30, 2018 compared to the same periods in 2017.

Segmented earnings for the six months ended June 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. As well, 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.

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 and ANR results are also affected by the contracting and pricing of their storage capacity and commodity sales.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$136 million and US$228 million for the three and six months ended June 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 in Midstream
- increased earnings due to the amortization of the net regulatory liabilities recognized in 2017 as a result of U.S. Tax Reform.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US$16 million and US$26 million for the three and six months ended June 30, 2018 compared to the same periods in 2017 mainly due to new projects placed in service.

Mexico Natural Gas Pipelines

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of US$, unless noted otherwise)	**2018**	**2017**	**2018**	**2017**
Topolobampo	**42**	40	**86**	80
Tamazunchale	**32**	27	**63**	56
Mazatlán	**19**	17	**39**	33
Guadalajara	**16**	17	**35**	34
Sur de Texas[1]	**1**	7	**10**	11
Other	**—**	—	**4**	—
Comparable EBITDA	**110**	108	**237**	214
Depreciation and amortization	**(18)**	(19)	**(37)**	(36)
Comparable EBIT	**92**	89	**200**	178
Foreign exchange impact	**26**	31	**55**	60
Comparable EBIT and segmented earnings (Cdn$)	**118**	120	**255**	238

1 Represents equity income from our 60 per cent interest.

Mexico Natural Gas Pipelines segmented earnings decreased by $2 million and increased by $17 million for the three and six months ended June 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 2018 had a negative impact on Canadian dollar equivalent segmented earnings from our Mexico operations compared to the same period in 2017.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$2 million and US$23 million for the three and six months ended June 30, 2018 compared to the same periods in 2017 and was primarily due to higher revenues from operations as a result of changes in timing of revenue recognition, partially offset by lower equity earnings from our investment in our Sur de Texas pipeline due to higher interest expense from an inter-affiliate loan with TCPL. The interest expense on the inter-affiliate loan is fully offset in Interest income and other.

DEPRECIATION AND AMORTIZATION

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

Liquids Pipelines

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Keystone Pipeline System	**352**	329	**692**	635
Intra-Alberta pipelines	**37**	—	**76**	—
Other[1]	**24**	3	**76**	9
Comparable EBITDA	**413**	332	**844**	644
Depreciation and amortization	**(85)**	(80)	**(168)**	(157)
Comparable EBIT	**328**	252	**676**	487
Specific items:				
Keystone XL asset costs	**—**	(5)	**—**	(13)
Risk management activities	**62**	4	**55**	4
Segmented earnings	**390**	251	**731**	478
Comparable EBIT denominated as follows:				
Canadian dollars	**89**	57	**182**	112
U.S. dollars	**185**	146	**387**	281
Foreign exchange impact	**54**	49	**107**	94
	328	252	**676**	487

1 Includes primarily liquids marketing and business development activities.

Liquids Pipelines segmented earnings increased by $139 million and $253 million for the three and six months ended June 30, 2018 compared to the same periods in 2017 and included:

- 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 gains in 2018 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.

Comparable EBITDA for Liquids Pipelines increased by $81 million and $200 million for the three and six months ended June 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
- higher contracted and spot volumes on the Keystone Pipeline System
- a higher contribution from liquids marketing activities
- lower business development costs as a result of capitalizing Keystone XL expenditures
- a weaker U.S. dollar which had a negative impact on the Canadian dollar equivalent earnings from our U.S. operations.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $5 million and $11 million for the three and six months ended June 30, 2018 compared to the same periods in 2017 as a result of new facilities being placed in service, partially offset by the effect of a weaker U.S. dollar.

Energy

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $, unless noted otherwise)	**2018**	**2017**	**2018**	**2017**
Canadian Power				
Western Power	**34**	23	**71**	53
Eastern Power[1]	**70**	83	**152**	177
Bruce Power[1]	**91**	132	**145**	223
U.S. Power (US$)[2]	**—**	32	**—**	86
Foreign exchange impact on U.S. Power	**—**	9	**—**	27
Natural Gas Storage and other	**10**	11	**17**	32
Business Development	**(3)**	(3)	**(7)**	(6)
Comparable EBITDA	**202**	287	**378**	592
Depreciation and amortization	**(33)**	(39)	**(65)**	(79)
Comparable EBIT	**169**	248	**313**	513
Specific items:				
U.S. Northeast power marketing contracts	**(15)**	—	**(7)**	—
Net gain on sales of U.S. Northeast power generation assets	**—**	492	**—**	481
Risk management activities	**37**	(95)	**(65)**	(151)
Segmented earnings	**191**	645	**241**	843

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 $454 million and $602 million for the three and six months ended June 30, 2018 compared to the same periods in 2017 and included the following specific items:

- a loss of $7 million year-to-date related to our U.S. Northeast power marketing contracts which included a loss of $15 million in second quarter and a gain of $8 million in first quarter primarily due to income recognized 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 will continue to run-off through to mid-2020
- a net gain of $492 million and $481 million before tax for the three and six months ended June 30, 2017, related to the monetization of our U.S. Northeast power generation assets
- unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks, as noted in the table below.

Risk management activities	three months ended June 30		six months ended June 30	
(unaudited - millions of $, pre-tax)	**2018**	**2017**	**2018**	**2017**
Canadian Power	**1**	3	**3**	4
U.S. Power	**39**	(94)	**(62)**	(156)
Natural Gas Storage and Other	**(3)**	(4)	**(6)**	1
Total unrealized gains/(losses) from risk management activities	**37**	(95)	**(65)**	(151)

The variances in these unrealized gains and losses reflect the impact of changes in forward natural gas and power prices and the volume of our positions for these derivatives over a certain period of time, however, they do not accurately reflect the gains and losses that will be realized on settlement, or the offsetting impacts of other derivative and non-derivative transactions that make up our business as a whole. As a result, we do not consider them reflective of our underlying operations.

Comparable EBITDA for Energy decreased by $85 million and $214 million for the three and six months ended June 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 sale of the U.S. Northeast power generation assets in second quarter 2017
- decreased Bruce Power earnings primarily due to lower volumes resulting from increased outage days and lower results from contracting activities. Additional financial and operating information on Bruce Power is provided below
- lower Eastern Power results mainly due to the sale of our Ontario solar assets in December 2017
- decreased Natural Gas Storage year-to-date results primarily due to lower realized natural gas storage price spreads
- increased Western Power results due to higher realized margins on higher generation volumes.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization decreased by $6 million and $14 million for the three and six months ended June 30, 2018 compared to the same periods in 2017 following the sale of our Ontario solar assets in December 2017.

BRUCE POWER

The following reflects our proportionate share of the components of comparable EBITDA and comparable EBIT.

	three months ended June 30		**six months ended June 30**	
(unaudited - millions of $, unless noted otherwise)	**2018**	**2017**	**2018**	**2017**
Equity income included in comparable EBITDA and EBIT comprised of:				
Revenues	**385**	428	**756**	829
Operating expenses	**(209)**	(209)	**(436)**	(433)
Depreciation and other	**(85)**	(87)	**(175)**	(173)
Comparable EBITDA and EBIT[1]	**91**	132	**145**	223
Bruce Power – other information				
Plant availability[2]	**89%**	92%	**87%**	91%
Planned outage days	**76**	41	**150**	97
Unplanned outage days	**3**	3	**34**	20
Sales volumes (GWh)[1]	**6,027**	6,309	**11,723**	12,292
Realized sales price per MWh[3]	**$67**	$68	**$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 is expected to occur on Units 3 and 8 in the second half of 2018. The overall average plant availability percentage in 2018 is expected to be in the high 80 per cent range.

Corporate

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Comparable EBITDA and EBIT	**(15)**	(12)	**(17)**	(16)
Specific items:				
Foreign exchange gain/(loss) – inter-affiliate loan[1]	**87**	(8)	**8**	(8)
Integration and acquisition related costs – Columbia	**—**	(20)	**—**	(49)
Segmented earnings/(losses)	**72**	(40)	**(9)**	(73)

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

Corporate segmented earnings increased by $112 million for the three months ended June 30, 2018 compared to the same period in 2017. For the six months ended June 30, 2018, Corporate segmented loss decreased by $64 million compared to the same period in 2017. These results included the following specific items that have been excluded from comparable EBIT:

- foreign exchange gains and losses 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 losses and gains included in Interest income and other on the inter-affiliate loan receivable which fully offset these amounts
- in 2017, pre-tax integration and acquisition costs associated with the acquisition of Columbia.

OTHER INCOME STATEMENT ITEMS

Interest expense

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Interest on long-term debt and junior subordinated notes				
Canadian dollar-denominated	**(131)**	(118)	**(265)**	(226)
U.S. dollar-denominated	**(332)**	(323)	**(646)**	(640)
Foreign exchange impact	**(97)**	(111)	**(180)**	(214)
	(560)	(552)	**(1,091)**	(1,080)
Other interest and amortization expense	**(54)**	(44)	**(97)**	(77)
Capitalized interest	**30**	56	**56**	101
Interest expense	**(584)**	(540)	**(1,132)**	(1,056)

Interest expense increased by $44 million and $76 million for the three and six months ended June 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 construction of Grand Rapids and Northern Courier in 2017
- higher related party debt financing
- final repayment of the Columbia acquisition bridge facilities in June 2017 resulting in lower interest expense and debt amortization expense
- the positive impact of a weaker U.S. dollar in translating U.S. dollar denominated interest.

Allowance for funds used during construction

(unaudited - millions of $)	three months ended June 30 2018	three months ended June 30 2017	six months ended June 30 2018	six months ended June 30 2017
Canadian dollar-denominated	**21**	55	**41**	105
U.S. dollar-denominated	**72**	49	**139**	87
Foreign exchange impact	**20**	17	**38**	30
Allowance for funds used during construction	**113**	121	**218**	222

AFUDC decreased by $8 million and $4 million for the three and six months ended June 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 the NGTL 2017 Expansion Program.

The increase in U.S. dollar-denominated AFUDC is primarily due to additional investment in and higher AFUDC rates on Columbia Gas growth projects and continued investment in Mexico projects.

Interest income and other

(unaudited - millions of $)	three months ended June 30 2018	three months ended June 30 2017	six months ended June 30 2018	six months ended June 30 2017
Interest income and other included in comparable earnings	**54**	40	**117**	45
Specific items:				
Foreign exchange (loss)/gain – inter-affiliate loan	**(87)**	8	**(8)**	8
Risk management activities	**(60)**	41	**(139)**	56
Interest income and other	**(93)**	89	**(30)**	109

Interest income and other decreased by $182 million and $139 million for the three and six months ended June 30, 2018 compared to the same periods in 2017 and was primarily the net effect of:

- interest income partially offset by the foreign exchange loss related to an inter-affiliate loan receivable from the Sur de Texas joint venture. The corresponding interest expense and foreign exchange gain are reflected in Income from equity investments in the Mexico Natural Gas Pipelines and Corporate segments, respectively. The offsetting currency-related 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
- foreign exchange impact on the translation of foreign currency denominated working capital balances
- realized gains in 2018 compared to realized losses in 2017 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- income of $18 million related to reimbursement of Coastal GasLink project costs recorded in 2017.

Income tax expense

(unaudited - millions of $)	three months ended June 30 2018	2017	six months ended June 30 2018	2017
Income tax expense included in comparable earnings	**(139)**	(193)	**(304)**	(433)
Specific items:				
U.S. Northeast power marketing contracts	**4**	—	**2**	—
Integration and acquisition related costs – Columbia	**—**	5	**—**	20
Keystone XL asset costs	**—**	1	**—**	2
Net gain on sales of U.S. Northeast power generation assets	**—**	(227)	**—**	(226)
Keystone XL income tax recoveries	**—**	—	**—**	7
Risk management activities	**(11)**	26	**41**	46
Income tax expense	**(146)**	(388)	**(261)**	(584)

Income tax expense included in comparable earnings decreased by $54 million and $129 million for the three and six months ended June 30, 2018 compared to the same periods in 2017 mainly 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 June 30 2018	2017	six months ended June 30 2018	2017
Net income attributable to non-controlling interests	**(76)**	(55)	**(170)**	(145)

Net income attributable to non-controlling interests increased by $21 million and $25 million for the three and six months ended June 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 six months ended June 30, 2018 was partially offset by our acquisition of the remaining outstanding publicly held common units of CPPL in February 2017.

Recent developments

CANADIAN NATURAL GAS PIPELINES

NGTL System

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 still being finalized and are currently anticipated to increase NGTL's capital program by approximately $0.1 billion, to $7.4 billion, excluding maintenance capital expenditures.

North Montney Project Approval

On May 23, 2018, the NEB issued a report recommending the Federal government approve the application for a variance 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 Federal government approved the recommendation on June 22, 2018 and on July 2, 2018 the NEB issued an amending order for the project.

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 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 is anticipated to be in service by second quarter 2020.

NGTL 2018-2019 Revenue Requirement Settlement Approval

On June 19, 2018, the NEB approved the 2018-2019 Settlement, as filed, for final 2018 tolls and revised interim 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.

2021 NGTL System Expansion Project Application

On June 20, 2018, we filed an application with the NEB for approval to construct and operate the 2021 Expansion Project. The project, 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.

Sundre Crossover 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.

Canadian Mainline

Canadian Mainline 2018 - 2020 Toll Review

On March 16, 2018, the NEB provided its Notice of Public Hearing for our Supplemental Agreement with the Eastern LDCs filed on December 18, 2017. Our reply evidence is due September 18, 2018. The NEB will provide further details regarding an oral or written hearing process to consider the written submissions of the interested parties.

Maple Compressor Expansion Project

We continue to await an NEB decision on our application seeking project approval and are reviewing project plans to continue to meet our in-service timelines.

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 after. 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.

TC PipeLines, LP

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. A number of uncertainties exist with respect to the changes resulting from the 2018 FERC Actions, which could materially adversely impact the earnings, cash flows and financial position of TC PipeLines, LP. Cash retained by TC PipeLines, LP is being used to fund its ongoing capital expenditures as well as the repayment of debt to prudently manage its financial metrics in anticipation of a reduction in revenues should its pipeline systems' rates be reset in response to the 2018 FERC Actions. As our ownership interest in TC PipeLines, LP is approximately 25 per cent, the impact of the 2018 FERC Actions related to TC PipeLines, LP is not expected to be significant to our consolidated earnings or cash flows.

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.

Mountaineer XPress and WB XPress

In first quarter 2018, estimated project costs were revised upwards to US$3.0 billion for Mountaineer XPress and US $0.9 billion for WB XPress, representing increases of US$0.4 billion and US$0.1 billion, respectively. These increases primarily 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 and resources to maintain our projected in-service dates.

Great Lakes and Northern Border 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.

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 it 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 of late 2018.

Tula and Villa de Reyes

We continue to work toward finalizing amending agreements for both of these pipelines with the CFE to formalize the schedule and payments resulting from their respective force majeure events. The CFE has commenced payments on both pipelines in accordance with the TSAs.

LIQUIDS PIPELINES

Keystone XL

In December 2017, an appeal to Nebraska's Court of Appeals was filed by intervenors after the Nebraska Public Service Commission (PSC) issued an approval of an alternative route for the Keystone XL project in November 2017. In March 2018, the Nebraska Supreme Court, on its own motion, agreed to bypass the Court of Appeals and hear the appeal case against the PSC's alternative route itself. We expect the Nebraska Supreme Court, as the final arbiter, could reach a decision by late 2018 or first quarter 2019.

On May 15, 2018, the U.S. Department of State filed a notice of its intent to prepare an environmental assessment for the Keystone XL mainline alternative route in Nebraska. Public comments were due in June 2018. On July 30, 2018, the U.S. Department of State issued a draft environmental assessment. Comments on the draft are to be filed by August 29, 2018. We expect the U.S. Department of State will have completed the supplemental environmental review by third or fourth quarter 2018.

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, 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 may be issued by year-end 2018.

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 August 1, 2018, we entered into an agreement to sell our interests in the Cartier Wind power facilities in Québec to Innergex Renewable Energy Inc. for gross proceeds of $630 million before closing adjustments. The sale is expected to be completed in fourth quarter 2018 subject to certain regulatory and other approvals and result in an estimated gain of $175 million ($130 million after tax) which will be recorded upon closing of the transaction.

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 portfolio management, cash on hand and substantial committed credit facilities. 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 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. See the 2018 FERC Actions section for further information.

At June 30, 2018, our current assets totaled $5.3 billion and current liabilities amounted to $13.6 billion, leaving us with a working capital deficit of $8.3 billion compared to a working capital deficit of $7.7 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 $9.3 billion of unutilized, unsecured credit facilities.

CASH PROVIDED BY OPERATING ACTIVITIES

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2018**	2017	**2018**	2017
Net cash provided by operations	**1,779**	1,340	**3,171**	2,621
(Decrease)/increase in operating working capital	**(362)**	(20)	**(156)**	140
Funds generated from operations[1]	**1,417**	1,320	**3,015**	2,761
Specific items:				
U.S. Northeast power marketing contracts	**15**	—	**7**	—
Integration and acquisition related costs – Columbia	**—**	20	**—**	52
Keystone XL asset costs	**—**	5	**—**	13
Net loss on sales of U.S. Northeast power generation assets	**—**	6	**—**	17
Comparable funds generated from operations[1]	**1,432**	1,351	**3,022**	2,843
Distributions paid to non-controlling interests	**(48)**	(69)	**(117)**	(149)
Non-recoverable maintenance capital expenditures[2]	**(66)**	(79)	**(130)**	(128)
Comparable distributable cash flow[1]	**1,318**	1,203	**2,775**	2,566

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

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

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 $81 million and $179 million for the three and six months ended June 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 our common shareholder before capital allocation.

The increase in comparable distributable cash flow for the three and six months ended June 30, 2018 compared to the same periods in 2017 reflects higher comparable funds generated from operations, as described above.

Beginning in second quarter 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 our shareholder. 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)/PROVIDED BY INVESTING ACTIVITIES

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Capital spending				
Capital expenditures	**(2,337)**	(1,792)	**(4,039)**	(3,352)
Capital projects in development	**(76)**	(56)	**(112)**	(98)
Contributions to equity investments	**(184)**	(473)	**(542)**	(665)
	(2,597)	(2,321)	**(4,693)**	(4,115)
Proceeds from sales of assets, net of transaction costs	**—**	4,147	**—**	4,147
Other distributions from equity investments	**—**	1	**121**	364
Deferred amounts and other	**(15)**	(169)	**95**	(253)
Net cash (used in)/provided by investing activities	**(2,612)**	1,658	**(4,477)**	143

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

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

Contributions to equity investments decreased in 2018 compared to 2017 primarily due to lower contributions to our proportionate share of Sur de Texas debt financing and Grand Rapids, which went into service in August 2017. This was partially offset by increased contributions to our Bruce Power and Millennium investments.

Other distributions from equity investments 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 sale of our U.S. Northeast power generation assets for net proceeds of $4,147 million.

CASH PROVIDED BY/(USED IN) FINANCING ACTIVITIES

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Notes payable (repaid)/issued, net	**(1,327)**	111	**485**	781
Long-term debt issued, net of issue costs[1]	**3,240**	817	**3,333**	817
Long-term debt repaid[1]	**(808)**	(4,418)	**(2,034)**	(5,469)
Junior subordinated notes issued, net of issue costs	**—**	1,489	**—**	3,471
Advances from affiliate	**451**	—	**666**	—
Dividends and distributions paid	**(663)**	(610)	**(1,283)**	(1,178)
Common shares issued	**234**	214	**426**	401
Partnership units of TC PipeLines, LP issued, net of issue costs	**—**	27	**49**	119
Common units of Columbia Pipeline Partners LP acquired	**—**	—	**—**	(1,205)
Net cash provided by/(used in) financing activities	**1,127**	(2,370)	**1,642**	(2,263)

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

LONG-TERM DEBT ISSUED

In second quarter 2018, TCPL issued US$1 billion of Senior Unsecured Notes due in May 2028 bearing interest at a fixed rate of 4.25 per cent, US$500 million of Senior Unsecured Notes due in May 2038 bearing interest at a fixed rate of 4.75 per cent as well as an additional US$1 billion of Senior Unsecured Notes due in May 2048 bearing interest at a fixed rate of 4.875 per cent.

In July 2018, TCPL issued $800 million of Medium Term Notes due in July 2048 bearing interest at a fixed rate of 4.182 per cent and $200 million of Medium Term Notes due in March 2028 bearing interest at a fixed rate of 3.39 per cent.

The net proceeds of the above debt issuances were used for general corporate purposes and to fund our capital program.

LONG-TERM DEBT REPAID

In second quarter 2018, long-term debt repaid included the retirement of US$500 million by Columbia Pipeline Group, Inc. of Senior Unsecured Notes bearing interest at a fixed rate of 2.45 per cent.

In first quarter 2018, long-term debt repaid included retirements by TCPL of US$500 million of Senior Unsecured Notes bearing interest at a fixed rate of 1.875 per cent, US$250 million of Senior Unsecured Notes bearing interest at a floating rate and $150 million of Debentures bearing interest at a fixed rate of 9.45 per cent.

COMMON SHARES ISSUED

We issued the following common shares to TransCanada during the year:

- 3.6 million shares on July 31, 2018 for proceeds of $207 million
- 4.3 million shares on April 30, 2018 for proceeds of $234 million
- 3.4 million shares on January 31, 2018 for proceeds of $192 million.

TC PIPELINES, LP ATM EQUITY ISSUANCE PROGRAM

In the six months ended June 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 June 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.

In light 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 will be reactivated.

DIVIDENDS

On August 1, 2018, we declared quarterly dividends as follows:

Quarterly dividend on our common shares
The dividend declared for the quarter ending September 30, 2018 is equal to the quarterly dividend to be paid on TransCanada's issued and outstanding common shares at the close of business on September 28, 2018.

SHARE INFORMATION

as at July 31, 2018	
Common shares	**Issued and outstanding**
	883 million

CREDIT FACILITIES

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

At July 31, 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$0.7 billion	TCPL USA	Used for TCPL USA general corporate purposes, guaranteed by TCPL	December 2018
US$1.0 billion	US$0.4 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 July 31, 2018, our operated affiliates had an additional $0.7 billion of undrawn capacity on committed credit facilities.

RELATED PARTY DEBT FINANCING

Related party debt outstanding at June 30, 2018 consists of the following credit facility due to affiliate:

Amount	Description	Matures
$3.2 billion	Unsecured $4.5 billion credit facility agreement with TransCanada used to repay indebtedness and for working capital and general corporate purposes.	Demand

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

CONTRACTUAL OBLIGATIONS

Our capital expenditure commitments have risen by approximately $0.8 billion since December 31, 2017 as a result of the net effect of increased commitments for Columbia Gas growth projects, NGTL and Keystone XL, 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 second 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 June 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 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 June 30, 2018, the balance of our loan receivable from the joint venture totaled MXN$17.5 billion or $1.2 billion (December 31, 2017 - MXN$14.4 billion or $919 million) and Interest income and other included $29 million and $56 million of interest income on this loan receivable for the three and six months ended June 30, 2018 (2017 - $3 million and $3 million). Amounts recognized in Interest income and other are offset by a corresponding proportionate share of interest expense recorded in Income from equity investments in our Mexico Natural Gas Pipelines segment.

INTEREST RATE RISK

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

FOREIGN EXCHANGE

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

A portion of our businesses generate earnings in U.S. dollars, but since we report our financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect our net income. As our U.S. dollar-denominated operations continue to grow, this exposure increases. The vast 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 June 30, 2018	**1.29**
three months ended June 30, 2017	1.34

six months ended June 30, 2018	**1.28**
six months ended June 30, 2017	1.33

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

Significant U.S. dollar-denominated amounts

	three months ended June 30		six months ended June 30	
(unaudited - millions of US $)	**2018**	**2017**	**2018**	**2017**
U.S. Natural Gas Pipelines comparable EBIT	**418**	298	**931**	729
Mexico Natural Gas Pipelines comparable EBIT[1]	**114**	89	**244**	178
U.S. Liquids Pipelines comparable EBIT	**185**	146	**387**	281
U.S. Power comparable EBIT [2]	**—**	32	**—**	86
AFUDC on U.S. dollar-denominated projects	**72**	49	**139**	87
Interest on U.S. dollar-denominated long-term debt	**(332)**	(323)	**(646)**	(640)
Capitalized interest on U.S. dollar-denominated capital expenditures	**3**	1	**6**	1
U.S. dollar non-controlling interests and other	**(65)**	(44)	**(145)**	(114)
	395	248	**916**	608

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

Net investment hedge

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

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

	June 30, 2018		December 31, 2017	
(unaudited - millions of Canadian $, unless noted otherwise)	Fair value[1,2]	Notional amount	Fair value[1,2]	Notional amount
U.S. dollar cross-currency interest rate swaps (maturing 2018 to 2019)[3]	**(80)**	**US 500**	(199)	US 1,200
U.S. dollar foreign exchange options (maturing 2018 to 2019)	**(16)**	**US 2,000**	5	US 500
	(96)	**US 2,500**	(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 six months ended June 30, 2018, Net income includes net realized gains of nil and $1 million, respectively (2017 - $1 million and $2 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)	June 30, 2018	December 31, 2017
Notional amount	**29,000 (US 22,000)**	25,400 (US 20,200)
Fair value	**30,800 (US 23,400)**	28,900 (US 23,100)

FINANCIAL INSTRUMENTS

With the exception of Long-term debt and Junior subordinated notes, our derivative and non-derivative financial instruments are recorded on the balance sheet at fair value unless they were entered into and continue to be held for the purpose of receipt or delivery in accordance with our normal purchase and sales exemptions and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain accounting exemptions.

Derivative instruments

We use derivative instruments to reduce volatility associated with fluctuations in commodity prices, interest rates and foreign exchange rates. We apply hedge accounting to derivative instruments that qualify and are designated for hedge accounting treatment.

The majority of derivative instruments that are not designated or do not qualify for hedge accounting treatment have been entered into as economic hedges to manage our exposure to market risk (held for trading). Changes in the fair value of held for trading derivative instruments are recorded in net income in the period of change. This may expose us to increased variability in reported operating results since the fair value of the held for trading derivative instruments can fluctuate significantly from period to period.

Balance sheet presentation of derivative instruments

The balance sheet classification of the fair value of derivative instruments is as follows:

(unaudited - millions of $)	June 30, 2018	December 31, 2017
Other current assets	**246**	332
Intangible and other assets	**63**	73
Accounts payable and other	**(355)**	(387)
Other long-term liabilities	**(52)**	(72)
	(98)	(54)

Unrealized and realized gains/(losses) of derivative instruments

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2018**	2017	**2018**	2017
Derivative instruments held for trading[1]				
Amount of unrealized gains/(losses) in the period				
Commodities[2]	**99**	(91)	**(10)**	(147)
Foreign exchange	**(60)**	41	**(139)**	56
Amount of realized gains/(losses) in the period				
Commodities	**19**	(37)	**129**	(85)
Foreign exchange	**4**	(5)	**19**	(9)
Derivative instruments in hedging relationships				
Amount of realized (losses)/gains in the period				
Commodities	**(4)**	7	**(1)**	13
Foreign exchange	**—**	—	**—**	5
Interest rate	**—**	—	**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 six months ended June 30, 2018 and 2017, there were no gains or losses included in Net income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

Derivatives in cash flow hedging relationships

The components of the Condensed consolidated statement of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests is as follows:

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2018**	2017	**2018**	2017
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]				
Commodities	**(3)**	(2)	**(6)**	3
Interest rate	**—**	—	**9**	1
	(3)	(2)	**3**	4
Reclassification of gains/(losses) on derivative instruments from AOCI to net income[1]				
Commodities[2]	**2**	(7)	**1**	(11)
Interest rate[3]	**7**	5	**12**	9
	9	(2)	**13**	(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 June 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 June 30, 2018 and December 31, 2017. If the credit-risk-related contingent features in these agreements were triggered on June 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 June 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 second 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 their 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 an intra-entity asset transfer 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 consolidated 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 consolidated 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 continue to monitor and analyze additional guidance and clarifications provided by the FASB.

The new guidance is effective January 1, 2019, with early adoption permitted. A modified retrospective transition approach is required for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. We have developed a preliminary inventory of existing lease agreements and have substantially completed our analysis on these leases but continue to evaluate the financial impact on our consolidated financial statements. We have also selected a system solution and are in 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.

Amortization on purchased callable debt securities

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

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.

Reconciliation of non-GAAP measures

(unaudited - millions of $)	three months ended June 30 2018	three months ended June 30 2017	six months ended June 30 2018	six months ended June 30 2017
Comparable EBITDA				
Canadian Natural Gas Pipelines	**545**	527	**1,039**	1,031
U.S. Natural Gas Pipelines	**704**	551	**1,508**	1,271
Mexico Natural Gas Pipelines	**142**	145	**302**	285
Liquids Pipelines	**413**	332	**844**	644
Energy	**202**	287	**378**	592
Corporate	**(15)**	(12)	**(17)**	(16)
Comparable EBITDA	**1,991**	1,830	**4,054**	3,807
Depreciation and amortization	**(570)**	(516)	**(1,105)**	(1,026)
Comparable EBIT	**1,421**	1,314	**2,949**	2,781
Specific items:				
Foreign exchange gain/(loss) – inter-affiliate loan	**87**	(8)	**8**	(8)
U.S. Northeast power marketing contracts	**(15)**	—	**(7)**	—
Net gain on sales of U.S. Northeast power generation assets	**—**	492	**—**	481
Integration and acquisition related costs – Columbia	**—**	(20)	**—**	(59)
Keystone XL asset costs	**—**	(5)	**—**	(13)
Risk management activities[1]	**99**	(91)	**(10)**	(147)
Segmented earnings	**1,592**	1,682	**2,940**	3,035

1

Risk management activities (unaudited - millions of $)	three months ended June 30 2018	three months ended June 30 2017	six months ended June 30 2018	six months ended June 30 2017
Canadian Power	**1**	3	**3**	4
U.S. Power	**39**	(94)	**(62)**	(156)
Liquids marketing	**62**	4	**55**	4
Natural Gas Storage	**(3)**	(4)	**(6)**	1
Total unrealized gains/(losses) from risk management activities	**99**	(91)	**(10)**	(147)

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

	2018		2017				2016	
(unaudited - millions of $)	Second	First	Fourth	Third	Second	First	Fourth	Third
Revenues	**3,195**	3,424	3,617	3,195	3,230	3,407	3,635	3,642
Net income/(loss) attributable controlling interests and to common shares	**806**	759	889	636	909	672	(334)	(118)
Comparable earnings	**789**	889	747	638	687	727	650	639

FACTORS AFFECTING QUARTERLY FINANCIAL INFORMATION BY BUSINESS SEGMENT

Quarter-over-quarter revenues and net income fluctuate for reasons that vary across our business segments.

In our Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Mexico Natural Gas Pipelines segments, except for seasonal fluctuations in short-term throughput volumes on U.S. pipelines, quarter-over-quarter revenues and net income generally remain relatively stable during any fiscal year. Over the long term, however, they fluctuate because of:

- regulators' decisions
- negotiated settlements with shippers
- acquisitions and divestitures
- developments outside of the normal course of operations
- newly constructed assets being placed in service.

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

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

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

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

FACTORS AFFECTING FINANCIAL INFORMATION BY QUARTER

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

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

In 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:

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

In second quarter 2017, comparable earnings also excluded:

- a $265 million net after-tax gain related to the monetization of our U.S. Northeast power business 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.

In third quarter 2016, comparable earnings also excluded:

- a $656 million after-tax impairment on the Ravenswood goodwill. As a result of information received during the process to monetize our U.S. Northeast power business in third quarter 2016, it was determined that the fair value of Ravenswood no longer exceeded its carrying value
- costs associated with the acquisition of Columbia including a charge of $67 million after tax primarily relating to retention, severance and integration expenses
- $28 million of income tax recoveries related to the realized loss on a third-party sale of Keystone XL plant and equipment. A provision for the expected loss on these assets was included in our fourth quarter 2015 impairment charge but the related tax recoveries could not be recorded until realized
- a charge of $9 million after tax related to Keystone XL costs for the maintenance and liquidation of project assets which were being expensed pending further advancement of the project
- a $3 million after-tax charge related to the monetization of our U.S. Northeast power business.

Condensed consolidated statement of income

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $)	**2018**	**2017**	**2018**	**2017**
Revenues				
Canadian Natural Gas Pipelines	**954**	922	**1,838**	1,804
U.S. Natural Gas Pipelines	**930**	879	**2,021**	1,873
Mexico Natural Gas Pipelines	**153**	150	**304**	293
Liquids Pipelines	**644**	501	**1,267**	973
Energy	**514**	778	**1,189**	1,694
	3,195	3,230	**6,619**	6,637
Income from Equity Investments	**265**	197	**345**	371
Operating and Other Expenses				
Plant operating costs and other	**822**	1,027	**1,696**	2,033
Commodity purchases resold	**324**	547	**921**	1,090
Property taxes	**152**	153	**302**	315
Depreciation and amortization	**570**	516	**1,105**	1,033
	1,868	2,243	**4,024**	4,471
Gain on Sale of Assets	**—**	498	**—**	498
Financial Charges				
Interest expense	**584**	540	**1,132**	1,056
Allowance for funds used during construction	**(113)**	(121)	**(218)**	(222)
Interest income and other	**93**	(89)	**30**	(109)
	564	330	**944**	725
Income before Income Taxes	**1,028**	1,352	**1,996**	2,310
Income Tax Expense				
Current	**89**	55	**139**	122
Deferred	**57**	333	**122**	462
	146	388	**261**	584
Net Income	**882**	964	**1,735**	1,726
Net income attributable to non-controlling interests	**76**	55	**170**	145
Net Income Attributable to Controlling Interests and to Common Shares	**806**	909	**1,565**	1,581

See accompanying notes to the Condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $)	2018	2017	2018	2017
Net Income	**882**	964	**1,735**	1,726
Other Comprehensive Income/(Loss), Net of Income Taxes				
Foreign currency translation gains and losses on net investment in foreign operations	**259**	(269)	**691**	(351)
Reclassification of foreign currency translation gains on net investment on disposal of foreign operations	**—**	(77)	**—**	(77)
Change in fair value of net investment hedges	**(13)**	(1)	**(15)**	(2)
Change in fair value of cash flow hedges	**(2)**	(2)	**5**	3
Reclassification to net income of gains and losses on cash flow hedges	**7**	(1)	**10**	(1)
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**2**	4	**—**	7
Other comprehensive income on equity investments	**6**	—	**12**	3
Other comprehensive income/(loss)	**259**	(346)	**703**	(418)
Comprehensive Income	**1,141**	618	**2,438**	1,308
Comprehensive income attributable to non-controlling interests	**116**	6	**276**	56
Comprehensive Income Attributable to Controlling Interests and to Common Shares	**1,025**	612	**2,162**	1,252

See accompanying notes to the Condensed consolidated financial statements.

Condensed consolidated statement of cash flows

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $)	**2018**	2017	**2018**	2017
Cash Generated from Operations				
Net income	**882**	964	**1,735**	1,726
Depreciation and amortization	**570**	516	**1,105**	1,033
Deferred income taxes	**57**	333	**122**	462
Income from equity investments	**(265)**	(197)	**(345)**	(371)
Distributions received from operating activities of equity investments	**231**	228	**465**	447
Employee post-retirement benefits funding, net of expense	**(3)**	6	**—**	9
Gain on sale of assets	**—**	(498)	**—**	(498)
Equity allowance for funds used during construction	**(79)**	(78)	**(157)**	(142)
Unrealized (gains)/losses on financial instruments	**(39)**	50	**149**	91
Other	**63**	(4)	**(59)**	4
Decrease/(increase) in operating working capital	**362**	20	**156**	(140)
Net cash provided by operations	**1,779**	1,340	**3,171**	2,621
Investing Activities				
Capital expenditures	**(2,337)**	(1,792)	**(4,039)**	(3,352)
Capital projects in development	**(76)**	(56)	**(112)**	(98)
Contributions to equity investments	**(184)**	(473)	**(542)**	(665)
Proceeds from sales of assets, net of transaction costs	**—**	4,147	**—**	4,147
Other distributions from equity investments	**—**	1	**121**	364
Deferred amounts and other	**(15)**	(169)	**95**	(253)
Net cash (used in)/provided by investing activities	**(2,612)**	1,658	**(4,477)**	143
Financing Activities				
Notes payable (repaid)/issued, net	**(1,327)**	111	**485**	781
Long-term debt issued, net of issue costs	**3,240**	817	**3,333**	817
Long-term debt repaid	**(808)**	(4,418)	**(2,034)**	(5,469)
Junior subordinated notes issued, net of issue costs	**—**	1,489	**—**	3,471
Advances from affiliate	**451**	—	**666**	—
Dividends on common shares	**(615)**	(541)	**(1,166)**	(1,029)
Distributions paid to non-controlling interests	**(48)**	(69)	**(117)**	(149)
Common shares issued	**234**	214	**426**	401
Partnership units of TC PipeLines, LP issued, net of issue costs	**—**	27	**49**	119
Common units of Columbia Pipeline Partners LP acquired	**—**	—	**—**	(1,205)
Net cash provided by/(used in) financing activities	**1,127**	(2,370)	**1,642**	(2,263)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**28**	(24)	**57**	(19)
Increase in Cash and Cash Equivalents	**322**	604	**393**	482
Cash and Cash Equivalents				
Beginning of period	**1,115**	845	**1,044**	967
Cash and Cash Equivalents				
End of period	**1,437**	1,449	**1,437**	1,449

See accompanying notes to the Condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		June 30, 2018	December 31, 2017
ASSETS			
Current Assets			
Cash and cash equivalents		**1,437**	1,044
Accounts receivable		**2,113**	2,537
Inventories		**403**	378
Assets held for sale		**458**	—
Other		**888**	691
		5,299	4,650
Plant, Property and Equipment	net of accumulated depreciation of $24,822 and $23,734, respectively	**61,446**	57,277
Equity Investments		**6,628**	6,366
Regulatory Assets		**1,361**	1,376
Goodwill		**13,734**	13,084
Loan Receivable from Affiliate		**1,173**	919
Intangible and Other Assets		**1,699**	1,423
Restricted Investments		**1,062**	915
		92,402	86,010
LIABILITIES			
Current Liabilities			
Notes payable		**2,359**	1,763
Accounts payable and other		**3,984**	4,071
Dividends payable		**624**	552
Due to affiliate		**3,217**	2,551
Accrued interest		**642**	605
Current portion of long-term debt		**2,812**	2,866
		13,638	12,408
Regulatory Liabilities		**4,603**	4,321
Other Long-Term Liabilities		**666**	727
Deferred Income Tax Liabilities		**5,700**	5,403
Long-Term Debt		**34,583**	31,875
Junior Subordinated Notes		**7,284**	7,007
		66,474	61,741
EQUITY			
Common shares, no par value		**22,187**	21,761
Issued and outstanding:	June 30, 2018 - 879 million shares		
	December 31, 2017 - 872 million shares		
Additional paid-in capital		**13**	—
Retained earnings		**2,809**	2,387
Accumulated other comprehensive loss		**(1,134)**	(1,731)
Controlling Interests		**23,875**	22,417
Non-controlling interests		**2,053**	1,852
		25,928	24,269
		92,402	86,010

Contingencies and Guarantees (Note 13)
Variable Interest Entities (Note 15)
Subsequent Events (Note 16)

See accompanying notes to the Condensed consolidated financial statements.

Condensed consolidated statement of equity

	six months ended June 30	
(unaudited - millions of Canadian $)	**2018**	**2017**
Common Shares		
Balance at beginning of period	**21,761**	20,981
Proceeds from shares issued	**426**	401
Balance at end of period	**22,187**	21,382
Additional Paid-In Capital		
Balance at beginning of period	**—**	211
Issuance of stock options	**6**	5
Dilution from TC PipeLines, LP units issued	**7**	13
Asset drop downs to TC PipeLines, LP	**—**	(202)
Columbia Pipeline Partners LP acquisition	**—**	(171)
Reclassification of additional paid-in capital deficit to retained earnings	**—**	144
Balance at end of period	**13**	—
Retained Earnings		
Balance at beginning of period	**2,387**	1,577
Net income attributable to controlling interests	**1,565**	1,581
Common share dividends	**(1,238)**	(1,087)
Adjustment related to income tax effects of asset drop downs to TC PipeLines, LP	**95**	—
Adjustment related to employee share-based payments	**—**	12
Reclassification of additional paid-in capital deficit to retained earnings	**—**	(144)
Balance at end of period	**2,809**	1,939
Accumulated Other Comprehensive Loss		
Balance at beginning of period	**(1,731)**	(960)
Other comprehensive income/(loss) attributable to controlling interests	**597**	(329)
Balance at end of period	**(1,134)**	(1,289)
Equity Attributable to Controlling Interests	**23,875**	22,032
Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	**1,852**	1,726
Net income attributable to non-controlling interests	**170**	145
Other comprehensive income/(loss) attributable to non-controlling interests	**106**	(89)
Issuance of TC PipeLines, LP units		
Proceeds, net of issue costs	**49**	119
Decrease in TCPL's ownership of TC PipeLines, LP	**(9)**	(21)
Distributions declared to non-controlling interests	**(115)**	(147)
Reclassification from common units of TC PipeLines, LP subject to rescission	**—**	106
Impact of Columbia Pipeline Partners LP acquisition	**—**	33
Balance at end of period	**2,053**	1,872
Total Equity	**25,928**	23,904

See accompanying notes to the Condensed consolidated financial statements.

Notes to Condensed consolidated financial statements (unaudited)

1. Basis of presentation

These Condensed consolidated financial statements of TransCanada PipeLines Limited (TCPL or the Company) have been prepared by management in accordance with U.S. GAAP. The accounting policies applied are consistent with those outlined in TCPL's annual audited consolidated financial statements for the year ended December 31, 2017, except as described in Note 2, Accounting changes. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in TCPL's 2017 Annual Report.

These Condensed consolidated financial statements reflect adjustments, all of which are normal recurring adjustments that are, in the opinion of management, necessary to reflect fairly the financial position and results of operations for the respective periods. These Condensed consolidated financial statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2017 audited consolidated financial statements included in TCPL's 2017 Annual Report. Certain comparative figures have been reclassified to conform with the current period's presentation.

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

USE OF ESTIMATES AND JUDGEMENTS

In preparing these financial statements, TCPL is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions. In the opinion of management, these Condensed consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies included in the annual audited consolidated financial statements for the year ended December 31, 2017, except as described in Note 2, Accounting changes.

2. Accounting changes

CHANGES IN ACCOUNTING POLICIES FOR 2018

Revenue from contracts with customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. The new guidance requires that an entity recognize revenue from these contracts in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in amounts that reflect the total consideration to which it expects to be entitled during the term of the contract in exchange for those promised goods or services. Goods or services that are promised to a customer are referred to as the Company's "performance obligations." The total consideration to which the Company expects to be entitled can include fixed and variable amounts. The Company has variable revenue that is subject to factors outside the Company's influence, such as market prices, actions of third parties and weather conditions. The Company considers this variable revenue to be "constrained" as it cannot be reliably estimated, and therefore recognizes variable revenue when the service is provided.

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

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

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

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

Financial instruments

In January 2016, the FASB issued new guidance on the accounting for equity investments and financial liabilities. The new guidance changes the income statement effect of equity investments and the recognition of changes in the fair value of financial liabilities when the fair value option is elected. The new guidance also requires the Company to assess valuation allowances for deferred tax assets related to available for sale debt securities in combination with their other deferred tax assets. This new guidance was effective January 1, 2018 and did not have a material impact on the Company's consolidated financial statements.

Income taxes

In October 2016, the FASB issued new guidance on the income tax effects of intra-entity transfers of assets other than inventory. The new guidance requires the recognition of deferred and current income taxes for an intra-entity asset transfer when the transfer occurs. The new guidance was effective January 1, 2018, was applied using a modified retrospective approach, and did not have a material impact on the Company's consolidated financial statements.

Restricted cash

In November 2016, the FASB issued new guidance on restricted cash and cash equivalents on the statement of cash flows. The new guidance requires that the statement of cash flows explain the change during the period in the total cash and cash equivalents balance, and amounts generally described as restricted cash or restricted cash equivalents. Restricted cash and cash equivalents will be included with cash and cash equivalents when reconciling the beginning of period and end of period total amounts on the statement of cash flows. This new guidance was effective January 1, 2018, was applied retrospectively, and did not have an impact on the Company's consolidated financial statements.

Employee post-retirement benefits

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

Hedge accounting

In August 2017, the FASB issued new guidance making more financial and non-financial hedging strategies eligible for hedge accounting. The new guidance also amends the presentation requirements relating to the change in fair value of a derivative and requires additional disclosures including cumulative basis adjustments for fair value hedges and the effect of hedging on individual line items in the consolidated statement of income. This new guidance is effective January 1, 2019 with early adoption permitted. This new guidance, which the Company elected to adopt effective January 1, 2018, was applied prospectively and did not have a material impact on the Company's consolidated financial statements.

FUTURE ACCOUNTING CHANGES

Leases

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

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

The new guidance is effective January 1, 2019, with early adoption permitted. A modified retrospective transition approach is required for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. The Company has developed a preliminary inventory of existing lease agreements and has substantially completed its analysis on these leases but continues to evaluate the financial impact on its consolidated financial statements. The Company has also selected a system solution and is in the testing stage of implementation. The Company continues to assess process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance and to analyze new contracts that may contain leases.

Measurement of credit losses on financial instruments

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

Goodwill impairment

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

Amortization on purchased callable debt securities

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

Income taxes

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

3. Segmented information

three months ended June 30, 2018 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**[1]	**Total**
Revenues	**954**	**930**	**153**	**644**	**514**	**—**	**3,195**
Intersegment revenues	**—**	**56**	**—**	**—**	**5**	**(61)** [2]	**—**
	954	**986**	**153**	**644**	**519**	**(61)**	**3,195**
Income from equity investments	**3**	**59**	**1**	**13**	**102**	**87** [3]	**265**
Plant operating costs and other	**(341)**	**(288)**	**(12)**	**(155)**	**(72)**	**46** [2]	**(822)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(324)**	**—**	**(324)**
Property taxes	**(71)**	**(53)**	**—**	**(27)**	**(1)**	**—**	**(152)**
Depreciation and amortization	**(265)**	**(163)**	**(24)**	**(85)**	**(33)**	**—**	**(570)**
Segmented Earnings	**280**	**541**	**118**	**390**	**191**	**72**	**1,592**
Interest expense							**(584)**
Allowance for funds used during construction							**113**
Interest income and other							**(93)**
Income before income taxes							**1,028**
Income tax expense							**(146)**
Net Income							**882**
Net income attributable to non-controlling interests							**(76)**
Net Income Attributable to Controlling Interests and to Common Shares							**806**

1 Includes intersegment eliminations.

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

3 Income from equity investments includes foreign exchange gains on the Company's inter-affiliate loan with Sur de Texas. The peso-denominated loan to the Sur de Texas joint venture represents the Company's proportionate share of debt financing for this joint venture.

three months ended June 30, 2017 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**[1]	**Total**
Revenues	922	879	150	501	778	—	3,230
Intersegment revenues	—	10	—	—	—	(10) [2]	—
	922	889	150	501	778	(10)	3,230
Income/(loss) from equity investments	2	57	5	(1)	142	(8) [3]	197
Plant operating costs and other	(328)	(347)	(10)	(147)	(173)	(22) [2]	(1,027)
Commodity purchases resold	—	—	—	—	(547)	—	(547)
Property taxes	(69)	(48)	—	(22)	(14)	—	(153)
Depreciation and amortization	(222)	(150)	(25)	(80)	(39)	—	(516)
Gain on sale of assets	—	—	—	—	498	—	498
Segmented Earnings/(Loss)	305	401	120	251	645	(40)	1,682
Interest expense							(540)
Allowance for funds used during construction							121
Interest income and other							89
Income before income taxes							1,352
Income tax expense							(388)
Net Income							964
Net income attributable to non-controlling interests							(55)
Net Income Attributable to Controlling Interests and to Common Shares							909

1 Includes intersegment eliminations.

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

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

six months ended June 30, 2018 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**[1]	**Total**
Revenues	**1,838**	**2,021**	**304**	**1,267**	**1,189**	**—**	**6,619**
Intersegment revenues	**—**	**81**	**—**	**—**	**47**	**(128)** [2]	**—**
	1,838	**2,102**	**304**	**1,267**	**1,236**	**(128)**	**6,619**
Income from equity investments	**6**	**126**	**12**	**28**	**165**	**8** [3]	**345**
Plant operating costs and other	**(664)**	**(612)**	**(14)**	**(346)**	**(171)**	**111** [2]	**(1,696)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(921)**	**—**	**(921)**
Property taxes	**(141)**	**(108)**	**—**	**(50)**	**(3)**	**—**	**(302)**
Depreciation and amortization	**(506)**	**(319)**	**(47)**	**(168)**	**(65)**	**—**	**(1,105)**
Segmented Earnings/(Loss)	**533**	**1,189**	**255**	**731**	**241**	**(9)**	**2,940**
Interest expense							**(1,132)**
Allowance for funds used during construction							**218**
Interest income and other							**(30)**
Income before income taxes							**1,996**
Income tax expense							**(261)**
Net Income							**1,735**
Net income attributable to non-controlling interests							**(170)**
Net Income Attributable to Controlling Interests and to Common Shares							**1,565**

1 Includes intersegment eliminations.

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

3 Income from equity investments includes foreign exchange gains on the Company's inter-affiliate loan with Sur de Texas. The peso-denominated loan to the Sur de Texas joint venture represents the Company's proportionate share of debt financing for this joint venture.

six months ended June 30, 2017 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**[1]	**Total**
Revenues	1,804	1,873	293	973	1,694	—	6,637
Intersegment revenues	—	21	—	—	—	(21) [2]	—
	1,804	1,894	293	973	1,694	(21)	6,637
Income/(loss) from equity investments	5	122	11	(1)	242	(8) [3]	371
Plant operating costs and other	(640)	(653)	(19)	(292)	(385)	(44) [2]	(2,033)
Commodity purchases resold	—	—	—	—	(1,090)	—	(1,090)
Property taxes	(138)	(95)	—	(45)	(37)	—	(315)
Depreciation and amortization	(444)	(306)	(47)	(157)	(79)	—	(1,033)
Gain on sale of assets	—	—	—	—	498	—	498
Segmented Earnings/(Loss)	587	962	238	478	843	(73)	3,035
Interest expense							(1,056)
Allowance for funds used during construction							222
Interest income and other							109
Income before income taxes							2,310
Income tax expense							(584)
Net Income							1,726
Net income attributable to non-controlling interests							(145)
Net Income Attributable to Controlling Interests and to Common Shares							1,581

1 Includes intersegment eliminations.

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

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

TOTAL ASSETS

(unaudited - millions of Canadian $)	**June 30, 2018**	**December 31, 2017**
Canadian Natural Gas Pipelines	**17,447**	16,904
U.S. Natural Gas Pipelines	**39,786**	35,898
Mexico Natural Gas Pipelines	**6,268**	5,716
Liquids Pipelines	**16,291**	15,438
Energy	**8,368**	8,503
Corporate	**4,242**	3,551
	92,402	86,010

4. Revenues

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

DISAGGREGATION OF REVENUES

The following tables summarizes total Revenues for the three and six months ended June 30, 2018:

three months ended June 30, 2018 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Total**
Revenues from contracts with customers						
Capacity arrangements and transportation	**954**	**785**	**152**	**513**	**—**	**2,404**
Power generation	**—**	**—**	**—**	**—**	**415**	**415**
Natural gas storage and other	**—**	**118**	**1**	**—**	**31**	**150**
	954	**903**	**153**	**513**	**446**	**2,969**
Other revenues[1,2]	**—**	**27**	**—**	**131**	**68**	**226**
	954	**930**	**153**	**644**	**514**	**3,195**

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

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

six months ended June 30, 2018 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Total**
Revenues from contracts with customers						
Capacity arrangements and transportation	**1,838**	**1,669**	**302**	**1,047**	**—**	**4,856**
Power generation	**—**	**—**	**—**	**—**	**1,005**	**1,005**
Natural gas storage and other	**—**	**310**	**2**	**1**	**61**	**374**
	1,838	**1,979**	**304**	**1,048**	**1,066**	**6,235**
Other revenues[1,2]	**—**	**42**	**—**	**219**	**123**	**384**
	1,838	**2,021**	**304**	**1,267**	**1,189**	**6,619**

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

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

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

Canadian Natural Gas Pipelines

Capacity Arrangements and Transportation

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

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

U.S. Natural Gas Pipelines

Capacity Arrangements and Transportation

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

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

Natural Gas Storage and Other

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

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

Mexico Natural Gas Pipelines

Capacity Arrangements and Transportation

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

Liquids Pipelines

Capacity Arrangements and Transportation

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

Energy

Power Generation

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

Natural Gas Storage and Other

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

FINANCIAL STATEMENT IMPACT OF ADOPTING REVENUE FROM CONTRACTS WITH CUSTOMERS

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

Capacity Arrangements and Transportation

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

Impact of New Revenue Recognition Guidance on Date of Adoption

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

(unaudited - millions of Canadian $)	As reported December 31, 2017	Adjustment	January 1, 2018
Current Assets			
Accounts receivable	2,537	(62)	2,475
Other[1]	691	79	770
Current Liabilities			
Accounts payable and other[2]	4,071	17	4,088

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

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

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

	June 30, 2018	
(unaudited - millions of Canadian $)	As reported	Pro-forma using legacy U.S. GAAP
Current Assets		
Accounts receivable	**2,113**	**2,355**
Other	**888**	**646**

CONTRACT BALANCES

(unaudited - millions of Canadian $)	June 30, 2018	January 1, 2018
Receivables from contracts with customers	**1,225**	1,736
Contract assets[1]	**242**	79
Contract liabilities[2]	**24**	17
Long-term contract liabilities[3]	**17**	—

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

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

FUTURE REVENUES FROM REMAINING PERFORMANCE OBLIGATIONS

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

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

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

Capacity Arrangements and Transportation

As at June 30, 2018, future revenues from long-term capacity arrangements and transportation contracts extending through 2043 are approximately $29.4 billion, of which approximately $2.8 billion is expected to be recognized during the remainder of 2018.

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

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

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

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

Power Generation

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

Natural Gas Storage and Other

As at June 30, 2018, future revenues from long-term natural gas storage and other contracts extending through 2033 are approximately $1.3 billion, of which approximately $260 million is expected to be recognized during the remainder of 2018. The Company applies the practical expedients related to contracts that are for a duration of one year or less and where it recognizes variable consideration, and therefore excludes the related revenues from the future revenues disclosure. As a result, this amount is lower than the potential total future revenues from these contracts.

5. Assets held for sale

Cartier Wind

On August 1, 2018, we entered into an agreement to sell our interests in the Cartier Wind power facilities in Québec to Innergex Renewable Energy Inc. for gross proceeds of $630 million before closing adjustments. The sale is expected to be completed in fourth quarter 2018, subject to certain regulatory and other approvals, and result in an estimated gain of $175 million ($130 million after tax) which will be recorded upon closing of the transaction.

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

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

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

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

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

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

In March 2018, FERC proposed changes related to U.S. Tax Reform and income taxes for rate-making purposes in a master limited partnership (MLP) that may have an impact on the future earnings and cash flows of FERC-regulated pipelines. On July 18, 2018, FERC issued final rulings with respect to these changes. Until these pronouncements are implemented through individual rate proceedings or settlements, and the Company and TC PipeLines, LP have fully evaluated their respective alternatives to minimize any negative impact of the proposed FERC changes, the Company believes that it is not more likely than not that the fair value of any of its reporting units is less than its respective carrying value. Therefore, a goodwill impairment test has not been performed during the six months ended June 30, 2018. The Company also determined there is no indication that the carrying values of plant, property and equipment and equity investments potentially impacted by FERC's changes are not recoverable. The Company will continue to monitor developments and assess its goodwill for impairment as well as review its plant, property and equipment and equity investments for recoverability as new information becomes available.

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 FERC developments, once finalized, could result in a goodwill impairment charge. The goodwill balance related to Great Lakes is US$573 million at June 30, 2018 (December 31, 2017 – US$573 million). There is also a risk that the goodwill balance related to Tuscarora of US$82 million at June 30, 2018 (December 31, 2017 – US$82 million) could be negatively impacted by the FERC developments.

7. Income taxes

U.S. Tax Reform

Pursuant to the enactment of U.S. Tax Reform, the Company recorded net regulatory liabilities and a corresponding reduction in net deferred income tax liabilities in the amount of $1,686 million at December 31, 2017 related to the Company's U.S. natural gas pipelines subject to rate-regulated accounting. Amounts recorded to adjust income taxes remain provisional as the Company's interpretation, assessment and presentation of the impact of U.S. Tax Reform may be further clarified with additional guidance from regulatory, tax and accounting authorities. Should additional guidance be provided by these authorities or other sources during the one-year measurement period permitted by the SEC, the Company will review the provisional amounts and adjust as appropriate. Other than the amortizations discussed below and the foreign exchange impacts, no adjustments were made to these amounts during the six months ended June 30, 2018. There may be prospective adjustments to the Company's net regulatory liabilities once the final impact of these changes is determined.

Commencing January 1, 2018, the Company has amortized the net regulatory liabilities using the Reverse South Georgia methodology. Under this methodology, rate-regulated entities determine amortization based on their composite depreciation rate and immediately begin recording amortization. Amortization of the net regulatory liabilities in the amount of $15 million and $24 million was recorded for the three and six months ended June 30, 2018 respectively and included in Revenues in the Condensed consolidated statement of income.

Effective Tax Rates

The effective income tax rates for the six-month periods ended June 30, 2018 and 2017 were 13 per cent and 25 per cent, respectively. The lower effective tax rate in 2018 was primarily the result of the rate change resulting from U.S. Tax Reform and lower flow-through income taxes in Canadian rate-regulated pipelines.

8. Long-term debt

LONG-TERM DEBT ISSUED

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

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

LONG-TERM DEBT RETIRED

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

(unaudited - millions of Canadian $, unless noted otherwise) Company	Retirement date	Type	Amount	Interest rate
COLUMBIA PIPELINE GROUP, INC.				
	June 2018	Senior Unsecured Notes	US 500	2.45%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM				
	May 2018	Senior Secured Notes	US 18	5.9%
TRANSCANADA PIPELINES LIMITED				
	March 2018	Debentures	150	9.45%
	January 2018	Senior Unsecured Notes	US 500	1.875%
	January 2018	Senior Unsecured Notes	US 250	Floating
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP				
	March 2018	Senior Unsecured Notes	US 9	6.73%

CAPITALIZED INTEREST

In the three and six months ended June 30, 2018, TCPL capitalized interest related to capital projects of $30 million and $56 million, respectively (2017 – $56 million and $101 million, respectively).

9. Common shares

On January 31, 2018, the Company issued 3.4 million common shares to TransCanada for proceeds of $192 million. On April 30, 2018, the Company issued 4.3 million common shares to TransCanada for proceeds of $234 million, resulting in 879 million shares outstanding at June 30, 2018 (December 31, 2017 - 872 million).

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

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

three months ended June 30, 2018 (unaudited - millions of Canadian $)	Before Tax Amount	Income Tax Recovery/ (Expense)	Net of Tax Amount
Foreign currency translation gains on net investment in foreign operations	**254**	**5**	**259**
Change in fair value of net investment hedges	**(17)**	**4**	**(13)**
Change in fair value of cash flow hedges	**(3)**	**1**	**(2)**
Reclassification to net income of gains and losses on cash flow hedges	**9**	**(2)**	**7**
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**4**	**(2)**	**2**
Other comprehensive income on equity investments	**6**	**—**	**6**
Other comprehensive income	**253**	**6**	**259**

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

six months ended June 30, 2018 (unaudited - millions of Canadian $)	Before Tax Amount	Income Tax Recovery/ (Expense)	Net of Tax Amount
Foreign currency translation gains on net investment in foreign operations	**670**	**21**	**691**
Change in fair value of net investment hedges	**(20)**	**5**	**(15)**
Change in fair value of cash flow hedges	**3**	**2**	**5**
Reclassification to net income of gains and losses on cash flow hedges	**13**	**(3)**	**10**
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**8**	**(8)**	**—**
Other comprehensive income on equity investments	**13**	**(1)**	**12**
Other comprehensive income	**687**	**16**	**703**

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

The changes in AOCI by component are as follows:

three months ended June 30, 2018 (unaudited - millions of Canadian $)	Currency Translation Adjustments	Cash Flow Hedges	Pension and OPEB Plan Adjustments	Equity Investments	Total[1]
AOCI balance at April 1, 2018	**(670)**	**(29)**	**(205)**	**(449)**	**(1,353)**
Other comprehensive income/(loss) before reclassifications[2]	**208**	**(2)**	**—**	**—**	**206**
Amounts reclassified from accumulated other comprehensive loss[3]	**—**	**5**	**2**	**6**	**13**
Net current period other comprehensive income	**208**	**3**	**2**	**6**	**219**
AOCI balance at June 30, 2018	**(462)**	**(26)**	**(203)**	**(443)**	**(1,134)**

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.
2 Other comprehensive income/(loss) before reclassifications on currency translation adjustments and cash flow hedges is net of non-controlling interest gains of $38 million and nil, respectively.
3 Amounts reclassified from AOCI on cash flow hedges and equity investments is net of non-controlling interest gains of $2 million and nil, respectively.

six months ended June 30, 2018 (unaudited - millions of Canadian $)	Currency Translation Adjustments	Cash Flow Hedges	Pension and OPEB Plan Adjustments	Equity Investments	Total[1]
AOCI balance at January 1, 2018	**(1,043)**	**(31)**	**(203)**	**(454)**	**(1,731)**
Other comprehensive income/(loss) before reclassifications[2,3]	**581**	**(2)**	**—**	**—**	**579**
Amounts reclassified from accumulated other comprehensive loss [4]	**—**	**7**	**—**	**11**	**18**
Net current period other comprehensive income	**581**	**5**	**—**	**11**	**597**
AOCI balance at June 30, 2018	**(462)**	**(26)**	**(203)**	**(443)**	**(1,134)**

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.
2 Other comprehensive income/(loss) before reclassifications on currency translation adjustments and cash flow hedges is net of non-controlling interest gains of $95 million and $7 million, respectively.
3 Losses related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be $21 million ($15 million, net of tax) at June 30, 2018. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.
4 Amounts reclassified from AOCI on cash flow hedges and equity investments are net of non-controlling interest gains of $3 million and $1 million, respectively.

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

	Amounts Reclassified From AOCI				
	three months ended June 30		six months ended June 30		Affected line item in the Condensed consolidated statement of income
(unaudited - millions of Canadian $)	2018	2017	2018	2017	
Cash flow hedges					
Commodities	**(2)**	7	**(1)**	11	Revenues (Energy)
Interest	**(5)**	(5)	**(9)**	(9)	Interest expense
	(7)	2	**(10)**	2	Total before tax
	2	(1)	**3**	(1)	Income tax expense
	(5)	1	**(7)**	1	Net of tax[1,3]
Pension and other post-retirement benefit plan adjustments					
Amortization of actuarial gains and losses	**(4)**	(4)	**(8)**	(8)	Plant operating costs and other[2]
	2	1	**8**	3	Income tax expense
	(2)	(3)	**—**	(5)	Net of tax[1]
Equity investments					
Equity income	**(6)**	—	**(13)**	(4)	Income from equity investments
	—	—	**2**	1	Income tax expense
	(6)	—	**(11)**	(3)	Net of tax[1,3]
Currency translation adjustments					
Realization of foreign currency translation gain on disposal of foreign operations	**—**	77	**—**	77	Gain on sale of assets
	—	—	**—**	—	Income tax expense
	—	77	**—**	77	Net of tax[1]

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

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

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

11. Employee post-retirement benefits

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

	three months ended June 30				six months ended June 30			
	Pension benefit plans		Other post-retirement benefit plans		Pension benefit plans		Other post-retirement benefit plans	
(unaudited - millions of Canadian $)	2018	2017	2018	2017	2018	2017	2018	2017
Service cost[1]	**31**	27	**1**	1	**61**	56	**2**	2
Other components of net benefit cost[1]								
Interest cost	**34**	28	**4**	3	**67**	62	**7**	7
Expected return on plan assets	**(55)**	(39)	**(4)**	(6)	**(110)**	(89)	**(8)**	(11)
Amortization of actuarial loss	**3**	4	**1**	—	**7**	8	**1**	—
Amortization of regulatory asset	**4**	1	**—**	1	**9**	7	**—**	1
	(14)	(6)	**1**	(2)	**(27)**	(12)	**—**	(3)
Net Benefit Cost	**17**	21	**2**	(1)	**34**	44	**2**	(1)

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

12. Risk management and financial instruments

RISK MANAGEMENT OVERVIEW

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

COUNTERPARTY CREDIT RISK

TCPL's maximum counterparty credit exposure with respect to financial instruments at June 30, 2018, without taking into account security held, consisted of cash and cash equivalents, accounts receivable, available for sale assets, derivative assets and loans receivable. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At June 30, 2018, there were no significant amounts past due or impaired, no significant credit risk concentration and no significant credit losses during the period.

LOAN RECEIVABLE FROM AFFILIATE

The Company holds a 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline. The Company accounts for the joint venture as an equity investment. In 2017, the Company entered into a MXN$21.3 billion unsecured revolving credit facility with the joint venture, which bears interest at a floating rate and matures in March 2022. Draws on the credit facility result in a loan receivable from the joint venture representing the Company's proportionate share of the debt financing requirements advanced to the joint venture. At June 30, 2018, the balance of the Company's loan receivable from the joint venture totaled MXN$17.5 billion or $1.2 billion (December 31, 2017 – MXN$14.4 billion or $919 million) and Interest income and other included $29 million and $56 million of interest income on this loan receivable for the three and six months ended June 30, 2018 (2017 – $3 million and $3 million). Amounts recognized in Interest income and other are offset by a corresponding proportionate share of interest expense recorded in Income from equity investments.

NET INVESTMENT IN FOREIGN OPERATIONS

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

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

	June 30, 2018		December 31, 2017	
(unaudited - millions of Canadian $, unless noted otherwise)	**Fair value[1,2]**	**Notional amount**	**Fair value[1,2]**	**Notional amount**
U.S. dollar cross-currency interest rate swaps (maturing 2018 to 2019)[3]	**(80)**	**US 500**	(199)	US 1,200
U.S. dollar foreign exchange options (maturing 2018 to 2019)	**(16)**	**US 2,000**	5	US 500
	(96)	**US 2,500**	(194)	US 1,700

1 Fair value equals carrying value.
2 No amounts have been excluded from the assessment of hedge effectiveness.
3 In the three and six months ended June 30, 2018, Net income includes net realized gains of nil and $1 million, respectively (2017 – $1 million and $2 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)	June 30, 2018	December 31, 2017
Notional amount	**29,000 (US 22,000)**	25,400 (US 20,200)
Fair value	**30,800 (US 23,400)**	28,900 (US 23,100)

FINANCIAL INSTRUMENTS

Non-derivative financial instruments

Fair value of non-derivative financial instruments

Available for sale assets are recorded at fair value which is calculated using quoted market prices where available. Certain non-derivative financial instruments included in Cash and cash equivalents, Accounts receivable, Intangible and other assets, Notes payable, Accounts payable and other, Due to affiliate, Accrued interest and Other long-term liabilities have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. Each of these instruments are classified in Level II of the fair value hierarchy.

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

Balance sheet presentation of non-derivative financial instruments

The following table details the fair value of the Company's non-derivative financial instruments, excluding those where carrying amounts approximate fair value, which are classified in Level II of the fair value hierarchy:

	June 30, 2018		December 31, 2017	
(unaudited - millions of Canadian $)	Carrying amount	Fair value	Carrying amount	Fair value
Long-term debt including current portion[1,2]	**(37,395)**	**(40,762)**	(34,741)	(40,180)
Junior subordinated notes	**(7,284)**	**(7,101)**	(7,007)	(7,233)
	(44,679)	**(47,863)**	(41,748)	(47,413)

1 Long-term debt is recorded at amortized cost except for US$1.3 billion (December 31, 2017 – US$1.1 billion) that is attributed to hedged risk and recorded at fair value.

2 Net income for the three and six months ended June 30, 2018 includes unrealized losses of $1 million and unrealized gains of $4 million, respectively, (2017 – losses of $1 million and gains of $1 million, respectively) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$1.3 billion of long-term debt at June 30, 2018 (December 31, 2017 – US$1.1 billion). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Available for sale assets summary

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

	June 30, 2018		December 31, 2017	
(unaudited - millions of Canadian $)	LMCI restricted investments	Other restricted investments[1]	LMCI restricted investments	Other restricted investments[1]
Fair values of fixed income securities[2]				
Maturing within 1 year	**—**	**24**	—	23
Maturing within 1-5 years	**—**	**105**	—	107
Maturing within 5-10 years	**85**	**—**	14	—
Maturing after 10 years	**857**	**—**	790	—
	942	**129**	804	130

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

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

	June 30, 2018		June 30, 2017	
(unaudited - millions of Canadian $)	LMCI restricted investments[1]	Other restricted investments[2]	LMCI restricted investments[1]	Other restricted investments[2]
Net unrealized gains in the period				
three months ended	**3**	**—**	13	—
six months ended	**5**	**1**	15	—
Net realized losses in the period				
three months ended	**(3)**	**—**	(1)	—
six months ended	**(3)**	**—**	(1)	—

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

2 Gains and losses on other restricted investments are included in Interest income and other.

Derivative instruments

Fair value of derivative instruments

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

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

Balance sheet presentation of derivative instruments

The balance sheet classification of the fair value of derivative instruments is as follows:

at June 30, 2018 (unaudited - millions of Canadian $)	**Cash Flow Hedges**	**Fair Value Hedges**	**Net Investment Hedges**	**Held for Trading**	**Total Fair Value of Derivative Instruments**[1]
Other current assets					
Commodities[2]	—	—	—	**221**	**221**
Foreign exchange	—	—	**10**	**11**	**21**
Interest rate	**4**	—	—	—	**4**
	4	—	**10**	**232**	**246**
Intangible and other assets					
Commodities[2]	—	—	—	**46**	**46**
Foreign exchange	—	—	**2**	—	**2**
Interest rate	**15**	—	—	—	**15**
	15	—	**2**	**46**	**63**
Total Derivative Assets	**19**	—	**12**	**278**	**309**
Accounts payable and other					
Commodities[2]	**(8)**	—	—	**(158)**	**(166)**
Foreign exchange	—	—	**(93)**	**(90)**	**(183)**
Interest rate	—	**(6)**	—	—	**(6)**
	(8)	**(6)**	**(93)**	**(248)**	**(355)**
Other long-term liabilities					
Commodities[2]	**(2)**	—	—	**(32)**	**(34)**
Foreign exchange	—	—	**(15)**	—	**(15)**
Interest rate	—	**(3)**	—	—	**(3)**
	(2)	**(3)**	**(15)**	**(32)**	**(52)**
Total Derivative Liabilities	**(10)**	**(9)**	**(108)**	**(280)**	**(407)**
Total Derivatives	**9**	**(9)**	**(96)**	**(2)**	**(98)**

1 Fair value equals carrying value.

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

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

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

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

Derivatives in fair value hedging relationships

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

	Carrying amount		Fair value hedging adjustments[1]	
(unaudited - millions of Canadian $)	June 30, 2018	December 31, 2017	June 30, 2018	December 31, 2017
Current portion of long-term debt	**(1,114)**	(688)	**4**	1
Long-term debt	**(520)**	(685)	**5**	4
	(1,634)	(1,373)	**9**	5

1 At June 30, 2018 and December 31, 2017, adjustments for discontinued hedging relationships included in the balance were nil.

Notional and Maturity Summary

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

at June 30, 2018 (unaudited)	Power	Natural Gas	Liquids	Foreign Exchange	Interest
Purchases[1]	**38,381**	**87**	**40**	**—**	**—**
Sales[1]	**27,191**	**92**	**52**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**3,504**	**2,450**
Maturity dates	**2018-2022**	**2018-2021**	**2018-2019**	**2018-2019**	**2018-2028**

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

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

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

Unrealized and realized gains/(losses) on derivative instruments

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $)	2018	2017	2018	2017
Derivative Instruments Held for Trading[1]				
Amount of unrealized gains/(losses) in the period				
Commodities[2]	**99**	(91)	**(10)**	(147)
Foreign exchange	**(60)**	41	**(139)**	56
Amount of realized gains/(losses) in the period				
Commodities	**19**	(37)	**129**	(85)
Foreign exchange	**4**	(5)	**19**	(9)
Derivative Instruments in Hedging Relationships				
Amount of realized (losses)/gains in the period				
Commodities	**(4)**	7	**(1)**	13
Foreign exchange	**—**	—	**—**	5
Interest rate	**—**	—	**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 six months ended June 30, 2018 and 2017, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

Derivatives in cash flow hedging relationships

The components of OCI related to the change in fair value of derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests are as follows:

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $)	**2018**	2017	**2018**	2017
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]				
Commodities	**(3)**	(2)	**(6)**	3
Interest rate	**—**	—	**9**	1
	(3)	(2)	**3**	4

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

Effect of fair value and cash flow hedging relationships

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

	three months ended June 30			
	Revenues (Energy)		Interest Expense	
(unaudited - millions of Canadian $)	**2018**	2017	**2018**	2017
Total Amount Presented in the Condensed Consolidated Statement of Income	**514**	778	**(584)**	(540)
Fair Value Hedges				
Interest rate contracts				
Hedged items	**—**	—	**(22)**	(19)
Derivatives designated as hedging instruments	**—**	—	**(2)**	1
Cash Flow Hedges				
Reclassification of gains/(losses) on derivative instruments from AOCI to net income				
Interest rate contracts[1]	**—**	—	**3**	1
Commodity contracts[2]	**2**	(7)	**—**	—
Reclassification of gains on derivative instruments from AOCI to net income as a result of forecasted transactions that are no longer probable of occurring				
Interest rate contracts[1]	**—**	—	**4**	4

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

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

(unaudited - millions of Canadian $)	six months ended June 30			
	Revenues (Energy)		Interest Expense	
	2018	2017	2018	2017
Total Amount Presented in the Condensed Consolidated Statement of Income	**1,189**	1,694	**(1,132)**	(1,056)
Fair Value Hedges				
Interest rate contracts				
Hedged items	**—**	—	**(42)**	(38)
Derivatives designated as hedging instruments	**—**	—	**(2)**	2
Cash Flow Hedges				
Reclassification of gains/(losses) on derivative instruments from AOCI to net income				
Interest rate contracts[1]	**—**	—	**4**	1
Commodity contracts[2]	**1**	(11)	**—**	—
Reclassification of gains on derivative instruments from AOCI to net income as a result of forecasted transactions that are no longer probable of occurring				
Interest rate contracts[1]	**—**	—	**8**	8

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

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

Offsetting of derivative instruments

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

at June 30, 2018 (unaudited - millions of Canadian $)	Gross derivative instruments	Amounts available for offset[1]	Net amounts
Derivative instrument assets			
Commodities	**267**	**(139)**	**128**
Foreign exchange	**23**	**(23)**	**—**
Interest rate	**19**	**(1)**	**18**
	309	**(163)**	**146**
Derivative instrument liabilities			
Commodities	**(200)**	**139**	**(61)**
Foreign exchange	**(198)**	**23**	**(175)**
Interest rate	**(9)**	**1**	**(8)**
	(407)	**163**	**(244)**

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

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

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

With respect to the derivative instruments presented above, the Company provided cash collateral of $125 million and letters of credit of $12 million as at June 30, 2018 (December 31, 2017 – $165 million and $30 million) to its counterparties. At June 30, 2018, the Company held nil in cash collateral and $1 million in letters of credit (December 31, 2017 – nil and $3 million) from counterparties on asset exposures.

Credit risk related contingent features of derivative instruments

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

Based on contracts in place and market prices at June 30, 2018, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $2 million (December 31, 2017 – $2 million), for which the Company did not provide collateral in the normal course of business at June 30, 2018 or December 31, 2017. If the credit-risk-related contingent features in these agreements were triggered on June 30, 2018, the Company would have been required to provide collateral of $2 million (December 31, 2017 – $2 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

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

FAIR VALUE HIERARCHY

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

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

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

at June 30, 2018 (unaudited - millions of Canadian $)	**Quoted prices in active markets (Level I)**[1]	**Significant other observable inputs (Level II)**[1]	**Significant unobservable inputs (Level III)**[1]	**Total**
Derivative instrument assets				
Commodities	**75**	**103**	**89**	**267**
Foreign exchange	**—**	**23**	**—**	**23**
Interest rate	**—**	**19**	**—**	**19**
Derivative instrument liabilities				
Commodities	**(72)**	**(79)**	**(49)**	**(200)**
Foreign exchange	**—**	**(198)**	**—**	**(198)**
Interest rate	**—**	**(9)**	**—**	**(9)**
	3	**(141)**	**40**	**(98)**

1 There were no transfers from Level I to Level II or from Level II to Level III for the six months ended June 30, 2018.

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

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

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

	three months ended June 30		**six months ended June 30**	
(unaudited - millions of Canadian $)	**2018**	**2017**	**2018**	**2017**
Balance at beginning of period	**(18)**	10	**(7)**	16
Total gains/(losses) included in Net income	**20**	(2)	**18**	(2)
Settlements	**32**	5	**23**	5
Sales	**—**	(3)	**—**	(5)
Transfers out of Level III	**6**	(1)	**6**	(5)
Balance at end of period[1]	**40**	9	**40**	9

1 For the three and six months ended June 30, 2018, Revenues include unrealized gains of $50 million and $44 million, respectively, attributed to derivatives in the Level III category that were still held at June 30, 2018 (2017 – unrealized losses of $1 million and unrealized gains of $1 million, respectively).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $16 million increase or decrease, respectively, in the fair value of outstanding derivative instruments included in Level III as at June 30, 2018.

13. Contingencies and guarantees

CONTINGENCIES

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

GUARANTEES

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

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

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

The carrying value of these guarantees has been included in Other long-term liabilities on the Condensed consolidated balance sheet. Information regarding the Company's guarantees is as follows:

		at June 30, 2018		at December 31, 2017	
(unaudited - millions of Canadian $)	Term	Potential exposure[1]	Carrying value	Potential exposure[1]	Carrying value
Sur de Texas	ranging to 2020	**203**	**1**	315	2
Bruce Power	ranging to 2019	**88**	**—**	88	1
Other jointly-owned entities	ranging to 2059	**104**	**11**	104	13
		395	**12**	507	16

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

14. Related party transactions

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

The following amounts are included in Due to affiliate:

		2018		2017	
(millions of Canadian $)	**Maturity Date**	**Outstanding June 30**	**Effective Interest Rate**	**Outstanding December 31**	**Effective Interest Rate**
Credit Facility[1]	Demand	**3,217**	**3.45%**	2,551	3.2%

1 TCPL has an unsecured $4.5 billion credit facility with TransCanada. Interest on this facility is charged at the prime rate per annum.

In the three and six months ended June 30, 2018, Interest expense included $26 million and $48 million of interest charges as a result of inter-affiliate borrowing (June 30, 2017 - $16 million and $32 million).

At June 30, 2018, Accounts payable and other included $5 million due to TransCanada (December 31, 2017 - $16 million). In the three and six months ended June 30, 2018, the Company made interest payments of $25 million and $46 million to TransCanada (June 30, 2017 - $16 million and $32 million).

15. Variable interest entities

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

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

Consolidated VIEs

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

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

(unaudited - millions of Canadian $)	June 30, 2018	December 31, 2017
ASSETS		
Current Assets		
Cash and cash equivalents	**67**	41
Accounts receivable	**43**	63
Inventories	**24**	23
Other	**14**	11
	148	138
Plant, Property and Equipment	**3,654**	3,535
Equity Investments	**954**	917
Goodwill	**514**	490
Intangible and Other Assets	**15**	3
	5,285	5,083
LIABILITIES		
Current Liabilities		
Accounts payable and other	**66**	137
Dividends payable	**—**	1
Accrued interest	**24**	23
Current portion of long-term debt	**75**	88
	165	249
Regulatory Liabilities	**38**	34
Other Long-Term Liabilities	**2**	3
Deferred Income Tax Liabilities	**13**	13
Long-Term Debt	**3,287**	3,244
	3,505	3,543

Non-Consolidated VIEs

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

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

(unaudited - millions of Canadian $)	June 30, 2018	December 31, 2017
Balance sheet		
Equity investments	**4,382**	4,372
Off-balance sheet		
Potential exposure to guarantees	**171**	171
Maximum exposure to loss	**4,553**	4,543

16. Subsequent Events

Debt Issuance

On July 3, 2018, TCPL issued $800 million of Medium Term Notes, due in July 2048, bearing interest at a fixed rate of 4.182 per cent and $200 million of Medium Term Notes, due in March 2028, bearing interest at a fixed rate of 3.39 per cent.

Common Share Issuance

On July 31, 2018, the Company issued 3.6 million common shares to TransCanada for proceeds of $207 million.