QuarterlyReport to Shareholders

TransCanada
In business to deliver

TransCanada Reports Solid First Quarter 2016 Financial Results
Transformational Changes Position Company for Near- and Long-Term Growth

CALGARY, Alberta – **April 29, 2016** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada) today announced net income attributable to common shares for first quarter 2016 of $252 million or $0.36 per share compared to $387 million or $0.55 per share for the same period in 2015. Comparable earnings for first quarter 2016 were $494 million or $0.70 per share compared to $465 million or $0.66 per share for the same period in 2015. TransCanada's Board of Directors also declared a quarterly dividend of $0.565 per common share for the quarter ending June 30, 2016, equivalent to $2.26 per common share on an annualized basis.

"During the first quarter of 2016, our diverse portfolio of high-quality long-life assets generated steady results in what continues to be a challenging environment," said Russ Girling, TransCanada's president and chief executive officer. "Comparable earnings increased by six per cent while funds generated from operations of $1.1 billion were consistent with the same period last year."

On March 17, 2016, TransCanada announced an agreement to acquire Columbia Pipeline Group, Inc. (NYSE: CPGX or Columbia) for US$13 billion including approximately US$2.8 billion of assumed debt. Columbia operates an approximate 24,000-kilometre (km) (15,000-mile) network of interstate natural gas pipelines extending from New York to the Gulf of Mexico, with a significant presence in the Appalachia production basin. The assets complement our existing North American footprint which together will create an approximate 91,000 km or 57,000 mile natural gas pipeline system connecting North America's fastest growing supply basins to premium markets across the continent. On April 1, 2016, TransCanada completed the issuance of $4.4 billion of subscription receipts to finance a portion of the acquisition, representing the largest equity financing in Canadian history. The conversion of subscription receipts to common shares is subject to closing of the Columbia acquisition which, in turn, is subject to Columbia shareholder approval and certain regulatory approvals.

"The acquisition represents a rare opportunity to invest in an extensive, competitively-positioned, growing network of regulated natural gas pipeline and storage assets in the Marcellus and Utica shale gas regions," added Girling. "The addition of Columbia to our resilient base business is a transformational change and creates an industry-leading portfolio of near-term growth projects that further supports and may augment our expected eight to ten per cent annual dividend growth through 2020."

Highlights

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

- First quarter financial results
  - Net income attributable to common shares of $252 million or $0.36 per share
  - Comparable earnings of $494 million or $0.70 per share
  - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.5 billion
  - Funds generated from operations of $1.1 billion
  - Comparable distributable cash flow of $1.0 billion or $1.38 per common share
- Declared a quarterly dividend of $0.565 per common share for the quarter ending June 30, 2016. Subscription receipts to receive dividend equivalent payment.
- Announced an agreement and plan of merger to acquire Columbia Pipeline Group, Inc. for US$13 billion including the assumption of approximately US$2.8 billion in debt

- Completed the sale of $4.4 billion of subscription receipts which will be used to finance a portion of the Columbia acquisition
- Announced our intention to monetize the U.S. Northeast power assets and a minority interest in our Mexican natural gas pipeline business
- Awarded a contract to construct the US$550 million Tula-Villa de Reyes Pipeline in Mexico
- Terminated our Alberta Power Purchase Arrangements (PPAs)

Net income attributable to common shares decreased by $135 million to $252 million or $0.36 per share for the three months ended March 31, 2016 compared to the same period last year. First quarter 2016 included a net after-tax charge of $211 million for specific items including $176 million after tax relating to the remaining net book value associated with our investment in the Alberta PPAs as a result of our termination decision, $26 million relating to costs associated with the announced Columbia acquisition, $6 million after tax of Keystone XL costs for the maintenance and liquidation of project assets which are being expensed pending further advancement of the project and an additional $3 million after-tax loss on the sale of TC Offshore. Both periods included unrealized gains and losses from changes in risk management activities. All of these specific items are excluded from comparable earnings.

Comparable earnings for first quarter 2016 were $494 million or $0.70 per share compared to $465 million or $0.66 per share for the same period in 2015. A higher contribution from Bruce Power and net corporate financial results was partially offset by lower earnings from the Keystone System, Eastern Power, U.S. Power and Western Power.

Notable recent developments in Corporate, Natural Gas Pipelines, Liquids Pipelines and Energy include:

Corporate:

- *Acquisition of Columbia Pipeline Group:* On March 17, 2016, we entered into an agreement and plan of merger to acquire Columbia Pipeline Group, Inc. (Columbia). Columbia owns one of the largest interstate natural gas pipeline systems in the U.S., providing transportation, storage and related services to a variety of customers in the northeast, mid-west, mid-Atlantic and Gulf Coast regions. Its assets include Columbia Gas Transmission, which operates approximately 18,000 km (11,300 miles) of pipelines and 286 billion cubic feet of working gas storage capacity in the Marcellus and Utica shale production areas, and Columbia Gulf Transmission, an approximate 5,400 km (3,300 mile) pipeline system that extends from Appalachia to the Gulf Coast.

  Columbia shareholders will receive US$25.50 per share which represents an aggregate transaction value of approximately US$13 billion including the assumption of approximately US$2.8 billion of debt. We expect to finance the US$10.2 billion cash component of the acquisition through an offering of subscription receipts, which closed on April 1, 2016 for gross proceeds of approximately $4.4 billion, the planned monetization of our U.S. Northeast power assets and a minority interest in our Mexican natural gas pipeline business, and existing cash on hand. A syndicate of lenders have committed to provide debt bridge facilities in the amount of US$6.9 billion which will be utilized pending the realization of proceeds from the planned monetization of assets outlined. We expect the acquisition, net of financing and the planned asset monetization, to be accretive to earnings per share in the first full year of ownership. We are targeting US$250 million of annual cost, revenue and financing benefits.

  We and Columbia each filed a Hart-Scott-Rodino Notification with the U.S. Federal Trade Commission on April 4, 2016. We also both submitted a filing with the Committee on Foreign Investment in the United States (CFIUS) which was accepted on April 13, 2016. The special meeting for Columbia stockholders to approve the transaction is scheduled for June 22, 2016.

  We expect the acquisition to close in second half 2016 subject to the shareholder and regulatory approvals.

- *Subscription Receipts:* On April 1, 2016, we issued 96.6 million subscription receipts to partially fund the Columbia acquisition at a price of $45.75 each for total proceeds of approximately $4.4 billion. Each subscription receipt will entitle the holder to automatically receive one common share upon closing of the

Columbia acquisition. While the subscription receipts remain outstanding, holders will be entitled to receive cash payments per subscription receipt equivalent to dividends paid on each common share.

- ***Preferred Share Issuance:*** On April 20, 2016, we completed a public offering of 20 million Series 13 cumulative redeemable, minimum rate reset, first preferred shares at $25 per share resulting in gross proceeds of $500 million. The fixed dividend rate on the Series 13 preferred shares was set for five years at 5.5 per cent per annum. The dividend rate will reset every five years at a rate equal to the sum of the applicable five-year Government of Canada bond yield plus 4.69 per cent, provided that such rate shall be not less than 5.5 per cent per annum.

Natural Gas Pipelines:

- ***ANR Section 4 Rate Case***: On January 29, 2016, ANR filed a Section 4 Rate Case with the FERC that requests an increase to ANR's maximum transportation rates. On February 29, 2016, the FERC issued an order that accepted and suspended ANR's rate and tariff changes to become effective August 1, 2016, subject to refund and the outcome of a hearing. In addition, on March 23, 2016, the FERC established a procedural schedule for the hearing and appointed a settlement judge to assist the parties in their settlement negotiations. The hearing is currently scheduled for early February 2017 and settlement conferences will be held throughout the process.
- ***NGTL System***: In first quarter of 2016, we placed approximately $100 million of facilities in service with another $600 million currently under construction. The NGTL System continues to develop approximately $7.3 billion of new supply and demand facilities of which approximately $2.5 billion have received regulatory approval, a further approximately $1.9 billion are currently under regulatory review and applications for approval to construct and operate an additional $2.9 billion of facilities have yet to be filed.
- ***North Montney Mainline:*** On March 28, 2016, we filed a request with the NEB for a one year extension of the Certificate of Public Convenience and Necessity (CPCN) for the North Montney Mainline (NMML) project. The requested extension ensures our regulatory approvals remain valid and do not expire pending a Final Investment Decision (FID) on the proposed Pacific Northwest LNG project.
- ***2016-2017 NGTL Revenue Requirement Settlement:*** On April 7, 2016, the NEB approved, subject to certain reporting requirements, the NGTL revenue requirement settlement application that was filed in December 2015. The settlement includes a return on equity of 10.1 per cent on 40 per cent deemed equity plus certain incentive mechanisms.
- ***Iroquois Gas Transmission System*****:** On March 31, 2016, we closed the acquisition of an additional 4.87 per cent interest in Iroquois Gas Transmission System, L.P. (Iroquois) for US$54 million bringing our interest in Iroquois to 49.35 per cent. We also expect to acquire an additional 0.65 per cent in second quarter 2016 that will increase our overall interest to 50 per cent.
- ***Tula-Villa de Reyes Pipeline:*** On April 11, 2016, we announced we were awarded a contract to build, own and operate the Tula-Villa de Reyes pipeline in Mexico. Construction of the pipeline is supported by a 25-year natural gas transportation service contract for 886 million cubic feet per day with the Comisión Federal de Electricidad (CFE). We expect to invest approximately US$550 million on a 36-inch diameter, 420-km (261-mile) pipeline with an anticipated in-service in early 2018. The pipeline will extend from our Tamazunchale and Tuxpan-Tula pipelines to a terminus near Villa de Reyes, San Luis Potosí, transporting natural gas to power generation facilities.
- ***Prince Rupert Gas Transmission*****:** We are continuing engagement with Aboriginal groups and have now announced project agreements with eleven First Nation groups along the pipeline route which outline financial and other benefits and commitments that will be provided to each First Nation group for as long as the project is in service.

- *Coastal GasLink:* The LNG Canada joint venture participants anticipate reaching a final investment decision on their Kitimat-based LNG project in late 2016. Based on the current schedule, preliminary construction work could begin in January 2017.

Liquids Pipelines:

- *Keystone Pipeline*: On April 2, 2016, we shut down the Keystone pipeline after a leak was detected along the pipeline right-of-way in Hutchinson County, South Dakota. We reported the total volume of the release of 400 barrels to the National Response Center and the Pipeline and Hazardous Materials Safety and Administration (PHMSA). Temporary repairs were completed on April 9, 2016, and the Keystone pipeline was restarted on April 10, 2016. Permanent repairs and remaining restoration work at site is planned for May 2016, with further investigative activities and corrective measures required by PHMSA planned in 2016.
- *Energy East Pipeline*: On March 1, 2016, the Province of Québec filed a court action seeking an injunction to compel the Energy East Pipeline to comply with the province's environmental regulations. On April 22, 2016, we filed a project review engaging an environmental assessment under the Environmental Quality Act (Québec). This process is in addition to an environmental assessment required under the National Energy Board Act and the Canadian Environmental Assessment Act, 2012. The Attorney General for Québec has agreed to suspend its litigation against TransCanada and Energy East and to withdraw it once the provincial environmental assessment process has been completed. We do not anticipate this will result in a delay with regard to the National Energy Board's review process.

  On March 17, 2016, the first phase of Energy East public hearings for the voluntary Québec BAPE process was completed. The voluntary BAPE hearing process is intended to inform the Province of Québec in its participation in the federal process and provides project information to the public. A second phase, consisting of a series of public input sessions, has been suspended as it has been replaced with the environmental assessment.

Energy:

- *Alberta Power Purchase Arrangements:* On March 7, 2016, we issued notice to the Balancing Pool terminating our Alberta PPAs. The agreements contain a provision that permits the PPA buyers to terminate the PPAs if there is a change in law that makes the agreements unprofitable or more unprofitable. This termination affects the Sheerness, Sundance A and Sundance B PPAs. We expect the termination will improve cash flow and comparable earnings in the near term.

  As a result of the termination, we have recorded a non-cash impairment charge of $240 million before-tax ($176 million after-tax) which represents the remaining net book value of our investment in the PPAs.

Teleconference and Webcast:

We will hold a teleconference and webcast on Friday, April 29, 2016 to discuss our first quarter 2016 financial results. Russ Girling, TransCanada President and Chief Executive Officer, and Don Marchand, Executive Vice-President, Corporate Development and Chief Financial Officer, along with other members of the TransCanada executive leadership team, will discuss the financial results and Company developments at 1 p.m. (MDT) / 3 p.m. (EDT).

Members of the investment community and other interested parties are invited to participate by calling 866.223.7781 or 416.340.2216 (Toronto area). Please dial in 10 minutes prior to the start of the call. No pass code is required. A live webcast of the teleconference will be available at www.transcanada.com.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (EDT) on May 6, 2016. Please call 800.408.3053 or 905.694.9451 (Toronto area) and enter pass code 1793973.

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

With more than 65 years' experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and liquids pipelines, power generation and gas storage facilities. TransCanada operates a network of natural gas pipelines that extends more than 67,000 kilometres (42,000 miles), tapping into virtually all major gas supply basins in North America. TransCanada is one of the continent's largest providers of gas storage and related services with 368 billion cubic feet of storage capacity. A growing independent power producer, TransCanada owns or has interests in over 11,400 megawatts of power generation in Canada and the United States. TransCanada is developing one of North America's largest liquids delivery systems. TransCanada's common shares trade on the Toronto and New York stock exchanges under the symbol TRP. Visit TransCanada.com and our blog to learn more, or connect with us on social media and 3BL Media.

Forward Looking Information

This release contains certain information that is forward-looking and is subject to important risks and uncertainties (such statements are usually accompanied by words such as "anticipate", "expect", "believe", "may", "will", "should", "estimate", "intend" or other similar words). Forward-looking statements in this document are intended to provide TransCanada security holders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future plans and financial outlook. All forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this news release, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to update or revise any forward-looking information except as required by law. For additional information on the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, refer to TransCanada's Quarterly Report to Shareholders dated April 28, 2016 and 2015 Annual Report on our website at www.transcanada.com or filed under TransCanada's profile on SEDAR at www.sedar.com and with the U.S. Securities and Exchange Commission at www.sec.gov and available on TransCanada's website at www.transcanada.com.

Non-GAAP Measures

This news release contains references to non-GAAP measures, including comparable earnings, comparable EBITDA, comparable distributable cash flow, funds generated from operations, comparable earnings per share and comparable distributable cash flow per share, that do not have any standardized meaning as prescribed by U.S. GAAP and therefore are unlikely to be comparable to similar measures presented by other companies. These non-GAAP measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable. For more information on non-GAAP measures, refer to TransCanada's Quarterly Report to Shareholders dated April 28, 2016.

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Quarterly report to shareholders

First quarter 2016

Financial highlights

(unaudited - millions of $, except per share amounts)	three months ended March 31 2016	2015
Income		
Revenues	**2,547**	2,874
Net income attributable to common shares	**252**	387
per common share - basic and diluted	**$0.36**	$0.55
Comparable EBITDA[1]	**1,502**	1,531
Comparable earnings[1]	**494**	465
per common share[1]	**$0.70**	$0.66
Operating cash flow		
Funds generated from operations[1]	**1,125**	1,153
Increase in operating working capital	**(80)**	(393)
Net cash provided by operations	**1,045**	760
Comparable distributable cash flow[1]	**970**	956
per common share[1]	**$1.38**	$1.35
Investing activities		
Capital spending - capital expenditures	**836**	806
Capital spending - projects in development	**67**	163
Contributions to equity investments	**170**	93
Acquisitions, net of cash acquired	**995**	—
Proceeds from sale of assets, net of transaction costs	**6**	—
Dividends declared		
Per common share	**$0.565**	$0.52
Basic common shares outstanding (millions)		
Average for the period	**702**	709
End of period	**702**	709

1 Comparable EBITDA, comparable earnings, comparable earnings per common share, funds generated from operations, comparable distributable cash flow and comparable distributable cash flow per common share are all non-GAAP measures. See the non-GAAP measures section for more information.

Management's discussion and analysis

April 28, 2016

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TransCanada Corporation. It discusses our business, operations, financial position, risks and other factors for the three months ended March 31, 2016, and should be read with the accompanying unaudited condensed consolidated financial statements for the three months ended March 31, 2016 which have been prepared in accordance with U.S. GAAP.

This MD&A should also be read in conjunction with our December 31, 2015 audited consolidated financial statements and notes and the MD&A in our 2015 Annual Report.

About this document

Throughout this MD&A, the terms, ***we, us, our*** and ***TransCanada*** mean TransCanada Corporation and its subsidiaries. Abbreviations and acronyms that are not defined in this MD&A are defined in the glossary in our 2015 Annual Report. All information is as of April 28, 2016 and all amounts are in Canadian dollars, unless noted otherwise.

FORWARD-LOOKING INFORMATION

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

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

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

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

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

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

Assumptions

- timing and completion of the Columbia acquisition including receipt of regulatory and Columbia stockholder approval
- planned monetization of our U.S. Northeast power assets and a minority interest in our Mexican natural gas pipeline business
- inflation rates, commodity prices and capacity prices
- timing of financings and hedging
- regulatory decisions and outcomes
- termination of the Alberta PPAs
- foreign exchange rates
- interest rates
- tax rates
- planned and unplanned outages and the use of our pipeline and energy assets
- integrity and reliability of our assets
- access to capital markets
- anticipated construction costs, schedules and completion dates
- acquisitions and divestitures.

Risks and uncertainties

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

You can read more about these factors and others in reports we have filed with Canadian securities regulators and the SEC, including the MD&A in our 2015 Annual Report.

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, except as required by law.

FOR MORE INFORMATION

You can find more information about TransCanada in our annual information form and other disclosure documents, which are available on SEDAR (www.sedar.com).

NON-GAAP MEASURES

We use the following non-GAAP measures:

- EBITDA
- EBIT
- funds generated from operations
- distributable cash flow
- distributable cash flow per common share
- comparable earnings
- comparable earnings per common share
- comparable EBITDA
- comparable EBIT
- comparable distributable cash flow
- comparable distributable cash flow per common share
- comparable income from equity investments
- comparable interest expense
- comparable interest income and other expense
- comparable income tax expense.

These measures do not have any standardized meaning as prescribed by U.S. GAAP and therefore may not be comparable to similar measures presented by other entities. Please see the Reconciliation of non-GAAP measures section in this MD&A for a reconciliation of the GAAP measures to the non-GAAP measures.

EBITDA and EBIT

We use EBITDA as an approximate measure of our pre-tax operating cash flow. It measures our earnings before deducting financial charges, income tax, depreciation and amortization, net income attributable to non-controlling interests and preferred share dividends, and includes income from equity investments. EBIT measures our earnings from ongoing operations and is a useful measure of our performance and an effective tool for evaluating trends in each segment as it is equivalent to our segmented earnings. It is calculated in the same way as EBITDA, less depreciation and amortization.

Funds generated from operations

Funds generated from operations includes 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. See the Financial condition section for a reconciliation to net cash provided by operations.

Distributable cash flow

Distributable cash flow is defined as funds generated from operations plus distributions received in excess of equity earnings less preferred share dividends, distributions to non-controlling interests and maintenance capital expenditures. Maintenance capital expenditures are expenditures incurred to maintain our operating capacity, asset integrity and reliability and includes amounts attributable to our proportionate share of maintenance capital expenditures on our equity investments. We believe it is a useful supplemental measure of performance that defines cash available to common shareholders before capital allocation. See the Financial condition section for a reconciliation to net cash provided by operations.

Comparable measures

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

Comparable measure	Original measure
comparable earnings	net income attributable to common shares
comparable earnings per common share	net income per common share
comparable EBITDA	EBITDA
comparable EBIT	segmented earnings
comparable distributable cash flow	distributable cash flow
comparable distributable cash flow per common share	distributable cash flow per common share
comparable income from equity investments	income from equity investments
comparable interest expense	interest expense
comparable interest income and other expense	interest income and other expense
comparable income tax expense	income tax expense

Our decision not to include 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 rates
- gains or losses on sales of assets
- legal, contractual and bankruptcy settlements
- impact of regulatory or arbitration decisions relating to prior year earnings
- restructuring costs
- impairment of assets and investments
- acquisition costs.

We calculate comparable earnings by excluding 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.

Consolidated results - first quarter 2016

Certain costs previously reported in our Corporate segment are now being reported within the business segments as a result of our 2015 business transformation initiative. 2015 results have been restated to reflect this change.

	three months ended March 31	
(unaudited - millions of $, except per share amounts)	**2016**	**2015**
Natural Gas Pipelines	**607**	585
Liquids Pipelines	**218**	242
Energy	**(122)**	212
Corporate	**(60)**	(31)
Total segmented earnings	**643**	1,008
Interest expense	**(420)**	(318)
Interest income and other	**201**	(14)
Income before income taxes	**424**	676
Income tax expense	**(70)**	(207)
Net income	**354**	469
Net income attributable to non-controlling interests	**(80)**	(59)
Net income attributable to controlling interests	**274**	410
Preferred share dividends	**(22)**	(23)
Net income attributable to common shares	**252**	387
Net income per common share - basic and diluted	**$0.36**	$0.55

Net income attributable to common shares decreased by $135 million for the three months ended March 31, 2016 compared to the same period in 2015. The 2016 results included:

- a $176 million after-tax impairment charge on the carrying value of our Alberta PPAs as a result of our decision to terminate the PPAs
- a charge of $26 million relating to costs associated with the acquisition of Columbia
- a charge of $6 million after tax related to Keystone XL costs for the maintenance and liquidation of project assets which are being expensed pending further advancement of the project
- an additional $3 million after-tax loss on the sale of TC Offshore which closed on March 31, 2016.

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

Comparable earnings increased by $29 million for the three months ended March 31, 2016 compared to the same period in 2015 as discussed below in the reconciliation of net income to comparable earnings.

RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS

	three months ended March 31	
(unaudited - millions of $, except per share amounts)	2016	2015
Net income attributable to common shares	**252**	387
Specific items (net of tax):		
Alberta PPA terminations	**176**	—
Acquisition costs - Columbia Pipeline Group	**26**	—
Keystone XL asset costs	**6**	—
TC Offshore loss on sale	**3**	—
Risk management activities[1]	**31**	78
Comparable earnings	**494**	465
Net income per common share	**$0.36**	$0.55
Specific items (net of tax):		
Alberta PPA terminations	**0.25**	—
Acquisition costs - Columbia Pipeline Group	**0.04**	—
Keystone XL asset costs	**0.01**	—
TC Offshore loss on sale	**—**	—
Risk management activities	**0.04**	0.11
Comparable earnings per share	**$0.70**	$0.66

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Risk management activities	three months ended March 31	
(unaudited - millions of $)	2016	2015
Canadian Power	**(13)**	(22)
U.S. Power	**(115)**	(68)
Liquids	**(2)**	—
Natural Gas Storage	**5**	1
Foreign exchange	**53**	(29)
Income tax attributable to risk management activities	**41**	40
Total losses from risk management activities	**(31)**	(78)

Comparable earnings increased by $29 million for the three months ended March 31, 2016 compared to the same period in 2015. This was primarily the net effect of:

- higher interest income and other due to realized gains in 2016 compared to realized losses in 2015 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar denominated income and increased AFUDC related to our rate-regulated projects
- higher earnings from Bruce Power mainly due to higher gains from contracting activities, lower depreciation and our increased ownership interest, partially offset by higher planned outage days
- higher interest expense from debt issuances and lower capitalized interest from Keystone XL
- lower earnings from U.S. Power mainly due to decreased margins on sales to wholesale, commercial and industrial customers, the impact of lower realized prices in both New England and New York and lower capacity prices in New York, partially offset by incremental earnings from the Ironwood power plant in Lebanon, Pennsylvania acquired February 1, 2016
- lower earnings from Eastern Power due to lower earnings on the sale of unused natural gas transportation and lower contractual earnings at Bécancour
- lower earnings from Liquids Pipelines due to lower uncontracted volumes on the Keystone Pipeline System and lower volumes on Marketlink
- lower earnings from Western Power as a result of lower realized power prices and volumes.

The stronger U.S. dollar this quarter compared to the same period in 2015 positively impacted the translated results in our U.S. businesses, along with realized gains on foreign exchange hedges used to manage our exposure, however, this impact was partially offset by a corresponding increase in interest expense on U.S. dollar-denominated debt.

CAPITAL PROGRAM

We are developing quality projects under our long-term 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 $13 billion of near-term projects and $45 billion of commercially secured medium and longer-term projects. Amounts presented exclude the impact of foreign exchange, capitalized interest and AFUDC.

All projects are subject to cost adjustments due to market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits.

at March 31, 2016 (unaudited - billions of $)	**Estimated project cost**	**Carrying value**
Summary		
Near-term	13.3	4.3
Medium to longer-term	45.2	2.2
Total capital program	**58.5**	**6.5**
Foreign exchange impact on Capital Program[1]	3.5	0.7

1 Reflects U.S. foreign exchange rate of $1.30 at March 31, 2016.

at March 31, 2016 (unaudited - billions of $)	**Segment**	**Expected in-service date**	**Estimated project cost**	**Carrying value**
Houston Lateral and Terminal	Liquids Pipelines	2016	US 0.6	US 0.5
Topolobampo	Natural Gas Pipelines	2016	US 1.0	US 0.9
Mazatlan	Natural Gas Pipelines	2016	US 0.4	US 0.3
Canadian Mainline	Natural Gas Pipelines	2016-2017	0.7	0.1
NGTL - 2016/17 Facilities	Natural Gas Pipelines	2016-2018	2.7	0.5
- North Montney	Natural Gas Pipelines	2017	1.7	0.3
- 2018 Facilities	Natural Gas Pipelines	2018	0.6	—
- Other	Natural Gas Pipelines	2016-2017	0.4	—
Grand Rapids[1]	Liquids Pipelines	2017	0.9	0.6
Northern Courier	Liquids Pipelines	2017	1.0	0.6
Tuxpan-Tula	Natural Gas Pipelines	2017	US 0.5	US 0.1
Napanee	Energy	2017 or 2018	1.0	0.4
Tula-Villa de Reyes	Natural Gas Pipelines	2018	US 0.6	—
Bruce Power - life extension[1]	Energy	2016-2020	1.2	—
Total near-term projects			**13.3**	**4.3**

1 Our proportionate share.

at March 31, 2016 (unaudited - billions of $)	Segment	Estimated project cost	Carrying value
Heartland and TC Terminals	Liquids Pipelines	0.9	0.1
Upland	Liquids Pipelines	US 0.6	—
Grand Rapids Phase 2[1]	Liquids Pipelines	0.7	—
Bruce Power - life extension[1]	Energy	5.3	—
Keystone projects			
Keystone XL[2]	Liquids Pipelines	US 8.0	US 0.4
Keystone Hardisty Terminal[2]	Liquids Pipelines	0.3	0.1
Energy East projects			
Energy East[3]	Liquids Pipelines	15.7	0.8
Eastern Mainline	Natural Gas Pipelines	2.0	0.1
BC west coast LNG-related projects			
Coastal GasLink	Natural Gas Pipelines	4.8	0.3
Prince Rupert Gas Transmission	Natural Gas Pipelines	5.0	0.4
NGTL System - Merrick	Natural Gas Pipelines	1.9	—
Total medium to longer-term projects		**45.2**	**2.2**

1 Our proportionate share.
2 Carrying value reflects amount remaining after impairment charge recorded in fourth quarter 2015.
3 Excludes transfer of Canadian Mainline natural gas assets.

Outlook

Our overall earnings outlook for 2016 remains consistent with what was previously included in the 2015 Annual Report. Any changes in outlook with respect to specific lines of business are addressed within each business section of the MD&A. This outlook excludes the Columbia acquisition and related financing and asset sales. See Recent developments section for more information.

Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). Certain costs previously reported in our Corporate segment are now being reported within the business segments as a result of our 2015 business transformation initiative. 2015 results have been restated to reflect this change.

	three months ended March 31	
(unaudited - millions of $)	**2016**	**2015**
Comparable EBITDA	**898**	864
Depreciation and amortization	**(287)**	(279)
Comparable EBIT	**611**	585
Specific item:		
TC Offshore loss on sale	**(4)**	—
Segmented earnings	**607**	585

Natural Gas Pipelines segmented earnings increased by $22 million for the three months ended March 31, 2016 compared to the same period in 2015 and included an additional $4 million pre-tax loss on the sale of TC Offshore. This amount has been excluded from our calculation of comparable EBIT. The remainder of the Natural Gas Pipelines segmented earnings are equivalent to comparable EBIT, which, along with comparable EBITDA, are discussed below.

	three months ended March 31	
(unaudited - millions of $)	**2016**	**2015**
Canadian Pipelines		
Canadian Mainline	**240**	263
NGTL System	**234**	219
Foothills	**26**	26
Other Canadian pipelines[1]	**7**	6
Canadian Pipelines - comparable EBITDA	**507**	514
Depreciation and amortization	**(216)**	(209)
Canadian Pipelines - comparable EBIT	**291**	305
U.S. and International Pipelines (US$)		
ANR	**88**	86
TC PipeLines, LP[1,2]	**31**	26
Great Lakes[3]	**25**	20
Other U.S. pipelines (Iroquois[1], GTN[2,4], PNGTS[2,5])	**14**	41
Mexico (Guadalajara, Tamazunchale)	**41**	47
International and other[1,6]	**2**	2
Non-controlling interests[7]	**95**	74
U.S. and International Pipelines - comparable EBITDA	**296**	296
Depreciation and amortization	**(53)**	(57)
U.S. and International Pipelines - comparable EBIT	**243**	239
Foreign exchange impact	**84**	59
U.S. and International Pipelines - comparable EBIT (Cdn$)	**327**	298
Business Development comparable EBITDA and EBIT	**(7)**	(18)
Natural Gas Pipelines - comparable EBIT	**611**	585

1 Results from TQM, Northern Border, Iroquois and TransGas reflect our share of equity income from these investments. On March 31, 2016, we purchased an additional 4.87 per cent interest in Iroquois.

2 On April 1, 2015, we sold our remaining 30 per cent direct interest in GTN to TC PipeLines, LP. On January 1, 2016 we sold a 49.9 per cent interest in PNGTS to TC PipeLines, LP. The following shows our ownership interest in TC PipeLines, LP and our effective ownership interest of GTN, Great Lakes and PNGTS through our ownership interest in TC PipeLines, LP for the periods presented.

	Ownership percentage as of		
	March 31, 2016	**December 31, 2015**	**April 1, 2015**
TC PipeLines, LP	27.9	28.0	28.3
Effective ownership through TC PipeLines, LP:			
GTN	27.9	28.0	28.3
Great Lakes	13.0	13.0	13.1
PNGTS	13.9	—	—

3 Represents our 53.6 per cent direct ownership interest. The remaining 46.4 per cent is held by TC PipeLines, LP.

4 Effective April 1, 2015, we have no direct ownership in GTN. Prior to that our direct ownership interest was 30 per cent effective July 1, 2013.

5 Represents our 61.7 per cent ownership interest in 2015. Effective January 1, 2016, our direct ownership interest in PNGTS was 11.8 per cent as a result of the dropdown transaction between us and TC PipeLines, LP.

6 Includes our share of the equity income from TransGas as well as general and administration costs relating to our U.S. and International Pipelines.

7 Comparable EBITDA for the portions of TC PipeLines, LP and PNGTS we do not own.

CANADIAN PIPELINES

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

NET INCOME - WHOLLY OWNED CANADIAN PIPELINES

	three months ended March 31	
(unaudited - millions of $)	**2016**	**2015**
Canadian Mainline	**50**	47
NGTL System	**73**	64
Foothills	**4**	4

Net income for the Canadian Mainline increased by $3 million for the three months ended March 31, 2016 compared to the same period in 2015 primarily due to higher incentive earnings partially offset by a lower average investment base in 2016. No incentive earnings were recorded in the first quarter of 2015 because NEB approval of 2015 - 2020 compliance tolls for the NEB 2014 Decision was not received until June 2015. The NEB 2014 Decision included an approved ROE of 10.1 per cent with a possible range of achieved ROE outcomes between 8.7 per cent to 11.5 per cent.

Net income for the NGTL System increased by $9 million for the three months ended March 31, 2016 compared to the same period in 2015 mainly due to a higher average investment base.

U.S. AND INTERNATIONAL PIPELINES

Earnings for 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, including OM&A and property taxes. ANR is also affected by the contracting and pricing of its storage capacity and incidental commodity sales.

Comparable EBITDA for U.S. and International Pipelines was consistent for the three months ended March 31, 2016 compared to the same period in 2015. This was the net effect of:

- higher ANR Southeast mainline transportation revenues offset by a first quarter 2015 non-recurring settlement
- lower contributions from Mexico Pipelines
- higher transportation revenues from Great Lakes.

As well, a stronger U.S. dollar in first quarter 2016 had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. and International operations.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $8 million for three months ended March 31, 2016 compared to the same period in 2015 mainly because of a higher investment base on the NGTL System and the effect of a stronger U.S. dollar.

BUSINESS DEVELOPMENT

Business development expenses were lower by $11 million for the three months ended March 31, 2016 compared to the same period in 2015 mainly due to decreased business development activity.

OPERATING STATISTICS - WHOLLY OWNED PIPELINES

three months ended March 31	**Canadian Mainline**[1]		**NGTL System**[2]		**ANR**[3]	
(unaudited)	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**
Average investment base (millions of $)	**4,384**	5,018	**7,257**	6,419	**n/a**	n/a
Delivery volumes (Bcf):						
Total	**481**	529	**1,063**	1,058	**449**	509
Average per day	**5.3**	5.9	**11.7**	11.8	**4.9**	5.7

1 Canadian Mainline's throughput volumes represent physical deliveries to domestic and export markets. Physical receipts originating at the Alberta border and in Saskatchewan for the three months ended March 31, 2016 were 274 Bcf (2015 – 302 Bcf). Average per day was 3.0 Bcf (2015 – 3.4 Bcf).

2 Field receipt volumes for the NGTL System for the three months ended March 31, 2016 were 1,074 Bcf (2015 – 1,009 Bcf). Average per day was 11.8 Bcf (2015 – 11.2 Bcf).

3 Under its current rates, which are approved by the FERC, changes in average investment base do not affect results.

Liquids Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). Certain costs previously reported in our Corporate segment are now being reported within the business segments as a result of our 2015 business transformation initiative. 2015 results have been restated to reflect this change.

	three months ended March 31	
(unaudited - millions of $)	**2016**	**2015**
Comparable EBITDA	**300**	305
Depreciation and amortization	**(70)**	(63)
Comparable EBIT	**230**	242
Specific items:		
Keystone XL asset costs	**(10)**	—
Risk management activities	**(2)**	—
Segmented earnings	**218**	242

Liquids Pipelines segmented earnings decreased by $24 million for the three months ended March 31, 2016 compared to the same period in 2015 and included a $10 million pre-tax charge related to Keystone XL costs for the maintenance and liquidation of project assets which are being expensed pending further advancement of the project, and unrealized losses from changes in the fair value of derivatives related to our liquids marketing business. These amounts have been excluded from our calculation of comparable EBIT. The remainder of the Liquids Pipelines segmented earnings are equivalent to comparable EBIT, which, along with comparable EBITDA, are discussed below.

	three months ended March 31	
(unaudited - millions of $)	**2016**	**2015**
Keystone Pipeline System	**307**	311
Liquids Pipelines Business Development and Other	**(7)**	(6)
Liquids Pipelines - comparable EBITDA	**300**	305
Depreciation and amortization	**(70)**	(63)
Liquids Pipelines - comparable EBIT	**230**	242
Comparable EBIT denominated as follows:		
Canadian dollars	**55**	60
U.S. dollars	**130**	147
Foreign exchange impact	**45**	35
	230	242

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

Comparable EBITDA for the Keystone Pipeline System decreased by $4 million for the three months ended March 31, 2016 compared to the same period in 2015. The decrease was the net effect of:

- lower uncontracted volumes on Keystone Pipeline System
- lower volumes on Marketlink
- a stronger U.S. dollar which had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations

BUSINESS DEVELOPMENT AND OTHER

Business development and other expenses increased by $1 million for the three months ended March 31, 2016 compared to the same period in 2015.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $7 million for the three months ended March 31, 2016 compared to the same period in 2015 due to the effect of a stronger U.S. dollar.

OUTLOOK

Following our Keystone XL impairment charge in 2015, future expenditures on the project for the maintenance and liquidation of project assets, expected to be approximately $65 million before tax ($42 million after tax) in 2016, are being expensed pending further advancement of this project. These costs will be excluded from comparable earnings.

Energy

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). Certain costs previously reported in our Corporate segment are now being reported within the business segments as a result of our 2015 business transformation initiative. 2015 results have been restated to reflect this change.

	three months ended March 31	
(unaudited - millions of $)	**2016**	**2015**
Comparable EBITDA	**329**	386
Depreciation and amortization	**(88)**	(85)
Comparable EBIT	**241**	301
Specific items:		
Alberta PPA terminations	**(240)**	—
Risk management activities	**(123)**	(89)
Segmented (loss)/earnings	**(122)**	212

Energy segmented earnings decreased by $334 million for the three months ended March 31, 2016 compared to the same period in 2015 and included the following specific items that have been excluded from comparable EBIT:

- a $240 million pre-tax charge, which included a $29 million impairment of our equity investment in ASTC Power Partnership, on the carrying value of our Alberta PPAs as a result of our decision to terminate the PPAs
- unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain commodity price risks as follows:

Risk management activities	three months ended March 31	
(unaudited - millions of $, pre-tax)	**2016**	**2015**
Canadian Power	**(13)**	(22)
U.S. Power	**(115)**	(68)
Natural Gas Storage	**5**	1
Total losses from risk management activities	**(123)**	(89)

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 impact 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.

Following the March 17, 2016 announcement of our intention to sell the U.S. Northeast power assets, we were required to discontinue hedge accounting for certain cash flow hedges which resulted in a pre-tax net loss of $42 million for the three months ended March 31, 2016. This contributed to higher unrealized losses for U.S. Power risk management activities.

The remainder of the Energy segmented earnings are equivalent to comparable EBIT which, along with comparable EBITDA, are discussed below.

	three months ended March 31	
(unaudited - millions of $)	**2016**	**2015**
Canadian Power		
Western Power[1]	**4**	15
Eastern Power	**103**	130
Bruce Power	**114**	79
Canadian Power - comparable EBITDA[1,2]	**221**	224
Depreciation and amortization	**(46)**	(48)
Canadian Power - comparable EBIT[1,2]	**175**	176
U.S. Power (US$)		
U.S. Power - comparable EBITDA	**76**	132
Depreciation and amortization	**(30)**	(27)
U.S. Power - comparable EBIT	**46**	105
Foreign exchange impact	**17**	24
U.S. Power - comparable EBIT (Cdn$)	**63**	129
Natural Gas Storage and other - comparable EBITDA	**9**	3
Depreciation and amortization	**(3)**	(3)
Natural Gas Storage and other - comparable EBIT	**6**	—
Business Development comparable EBITDA and EBIT	**(3)**	(4)
Energy - comparable EBIT[1,2]	**241**	301

1 Included Sundance A and Sheerness PPAs, and Sundance B through our investment in ASTC Power Partnership up to March 7, 2016.
2 Included our share of equity income from our investments in ASTC Power Partnership up to March 7, 2016, Portlands Energy and Bruce Power.

Comparable EBITDA for Energy decreased by $57 million for the three months ended March 31, 2016 compared to the same period in 2015 due to the net effect of:

- lower earnings from U.S. Power mainly due to decreased margins on sales to wholesale, commercial and industrial customers, the impact of lower realized prices in both New England and New York and lower capacity prices in New York, partially offset by incremental earnings from the Ironwood power plant in Lebanon, Pennsylvania acquired February 1, 2016
- higher earnings from Bruce Power mainly due to higher gains from contracting activities, lower depreciation and our increased ownership interest, partially offset by higher planned outage days
- lower earnings from Eastern Power due to lower earnings on the sale of unused natural gas transportation and lower contractual earnings at Bécancour
- lower earnings from Western Power as a result of lower realized power prices and PPA volumes following the termination of the PPAs
- higher earnings from Natural Gas Storage due to higher realized natural gas storage price spreads.

CANADIAN POWER

Western and Eastern Power

(unaudited - millions of $)	three months ended March 31 2016	2015
Revenue[1]		
Western Power	**75**	108
Eastern Power	**95**	125
Other[2]	**29**	45
	199	278
Comparable income from equity investments[3]	**—**	5
Commodity purchases resold	**(59)**	(90)
Plant operating costs and other	**(46)**	(70)
Exclude risk management activities[1]	**13**	22
Comparable EBITDA[4]	**107**	145
Depreciation and amortization	**(46)**	(48)
Comparable EBIT[4]	**61**	97

Breakdown of comparable EBITDA		
Western Power[4]	**4**	15
Eastern Power	**103**	130
Comparable EBITDA[4]	**107**	145

1 The realized and unrealized gains and losses from financial derivatives used to manage Canadian Power's assets are presented on a net basis in Western and Eastern Power revenues. The unrealized gains and losses from financial derivatives included in revenue are excluded to arrive at Comparable EBITDA.

2 Includes revenues from the sale of unused natural gas transportation and sale of excess natural gas purchased for generation.

3 Includes our share of equity income from our investments in ASTC Power Partnership, which held the Sundance B PPA, and Portlands Energy. Comparable equity income excludes $29 million related to the Sundance B PPA termination which is held in ASTC Power Partnership and does not include any earnings related to our risk management activities.

4 Includes Sundance A, Sundance B and Sheerness PPAs up to March 7, 2016.

Sales volumes and plant availability

Includes our share of volumes from our equity investments.

	three months ended March 31	
(unaudited)	2016	2015
Sales volumes (GWh)		
Supply		
Generation		
Western Power	**690**	637
Eastern Power	**757**	1,323
Purchased		
Sundance A & B and Sheerness PPAs[1]	**1,823**	2,388
Other purchases	**8**	8
	3,278	4,356
Sales		
Contracted		
Western Power	**1,420**	1,645
Eastern Power	**757**	1,323
Spot		
Western Power	**1,101**	1,388
	3,278	4,356
Plant availability[2]		
Western Power[3]	**99%**	97%
Eastern Power[4,5]	**86%**	98%

1 Includes volumes from Sundance A and Sheerness PPAs and our 50 per cent ownership interest of Sundance B PPA through the ASTC Power Partnership up to March 7, 2016.

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

3 Does not include facilities that provided power to us under PPAs.

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

5 Plant availability was lower in the three months ended March 31, 2016 than the same period in 2015 due to an unplanned outage at the Halton Hills facility.

Western Power

Comparable EBITDA for Western Power decreased by $11 million for the three months ended March 31, 2016 compared to the same period in 2015 due to lower realized power prices and PPA volumes following the termination of the PPAs.

Results from the Alberta PPAs are included up to March 7, 2016 when we sent notice to the Balancing Pool to terminate the PPAs for the Sundance A, Sundance B and Sheerness facilities. Comparable income from equity investments included earnings from the ASTC Power Partnership which held our 50 per cent ownership in the Sundance B PPA. See the Recent developments section for more information on the PPA terminations.

The decrease in comparable equity earnings for the three months ended March 31, 2016 of $5 million compared to the same period in 2015 is primarily due to the impact of lower Alberta spot market prices on earnings from the ASTC Power Partnership. Comparable equity earnings do not include the impact of related contracting activities.

Average spot market power prices in Alberta decreased 38 per cent from $29/MWh to $18/MWh for the three months ended March 31, 2016 compared to the same period in 2015. The Alberta power market remained well supplied and few higher priced hours were observed in first quarter 2016. Warmer than normal temperatures prevailed leading to low power and natural gas prices. Realized power prices on power sales can be higher or lower than spot market power prices in any given period as a result of contracting activities.

Fifty-six per cent of Western Power sales volumes were sold under contract in first quarter 2016 compared to 54 per cent in first quarter 2015.

Depreciation and amortization decreased by $2 million following the termination of the PPAs.

We continue to expect Western Power 2016 earnings to be consistent with 2015 earnings. Although Alberta power prices are expected to remain low in 2016, the natural gas-fired cogeneration assets are expected to perform well in the lower gas price environment and the March 2016 decision to exercise the right to terminate the PPAs is expected to result in savings from the otherwise increased costs related to carbon emissions.

Eastern Power

Comparable EBITDA for Eastern Power decreased by $27 million for the three months ended March 31, 2016 compared to the same period in 2015 mainly due to lower earnings on the sale of unused natural gas transportation and lower contractual earnings at Bécancour.

BRUCE POWER

Results reflect our proportionate share. Bruce A and B were merged in December 2015 and comparative information for 2015 is reported on a combined basis to reflect the merged entity.

	three months ended March 31	
(unaudited - millions of $, unless noted otherwise)	**2016**	**2015**
Income from equity investments[1]	**114**	79
Comprised of:		
Revenues	**411**	331
Operating expenses	**(221)**	(172)
Depreciation and other	**(76)**	(80)
	114	79
Bruce Power - Other information		
Plant availability[2]	**88%**	93%
Planned outage days	**76**	39
Unplanned outage days	**8**	9
Sales volumes (GWh)[1]	**5,834**	4,984
Realized sales price per MWh[3,4]	**$65**	$64

1 Represents our 48.5 per cent ownership interest in Bruce Power after the merger on December 4, 2015 and our 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B up to December 3, 2015. 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 revenues from contract settlements and cost flow-through items.

4 Excludes unrealized gains and losses on contracting activities and revenues from cobalt sales.

Equity income from Bruce Power increased by $35 million for the three months ended March 31, 2016 compared to the same period in 2015. The increase was mainly due to higher gains from contracting activities, lower depreciation as a result of Bruce Power facility's operating life extension and our increased ownership interest, partially offset by higher planned outage days.

In December 2015, Bruce Power entered into an agreement with the IESO to extend the operating life of the Bruce Power facility to 2064. As part of this agreement, Bruce Power began receiving a uniform price of $65.73 per MWh, which includes certain flow-through items such as fuel and lease expenses recovery, for all units in January 2016. Over time, the price will be subject to adjustments for the return of and on capital invested under the Asset Management and Major Component Replacement capital programs, along with various other pricing adjustments that allow for a better matching of revenues and costs over the long term.

Bruce Power contract price[1]	**per MWh**
January 1, 2016 - March 31, 2016	$65.73
April 1, 2016 - March 31, 2017	$66.38

1 Includes fuel and lease expenses recovery on a flow-through basis estimated at $8.00 per MWh.

Prior to the amended agreement with the IESO, all of the output from Bruce Units 1 to 4 was sold at a fixed price/MWh which was adjusted annually on April 1 for inflation and other provisions under the contract.

Bruce Units 1 to 4 contract price[1]	**per MWh**
April 1, 2015 - December 31, 2015	$78.42
April 1, 2014 - March 31, 2015	$76.70

1 Includes fuel expense recovery on flow-through basis estimated at $5.00 per MWh.

Prior to the amended agreement with the IESO, all output from Bruce Units 5 to 8 was subject to a floor price adjusted annually for inflation on April 1.

Bruce Units 5 to 8 floor price	**per MWh**
April 1, 2015 - December 31, 2015	$54.13
April 1, 2014 - March 31, 2015	$52.86

Bruce Power also enters into fixed-price contracts under which it receives or pays the difference between the contract price and the spot price.

The contract with the IESO provides for payment if the IESO reduces Bruce Power's generation to balance the supply of and demand for electricity and/or manage other operating conditions of the Ontario power grid. The amount of the reduction is considered deemed generation for which Bruce Power is paid the contract price.

In January 2016, planned outage work commenced on Unit 8 and was completed on April 25, 2016. In April 2016, a planned outage on Unit 2 commenced which will continue concurrently with the station containment outage that is expected to occur later in second quarter 2016. The station containment outage inspects and maintains key safety systems including containment structures and is required to be completed approximately once every decade. As part of this work program, Bruce Units 1 to 4 are expected to be removed from service for approximately one month. Additional planned maintenance is scheduled for fourth quarter 2016. The overall average plant availability percentage in 2016 is expected to be in the low 80s.

U.S. POWER

(unaudited - millions of US$)	three months ended March 31 2016	2015
Revenue		
Power[1]	**331**	605
Capacity	**62**	67
	393	672
Commodity purchases resold	**(305)**	(476)
Plant operating costs and other[2]	**(99)**	(118)
Exclude risk management activities[1]	**87**	54
Comparable EBITDA	**76**	132
Depreciation and amortization	**(30)**	(27)
Comparable EBIT	**46**	105

1 The realized and unrealized gains and losses from financial derivatives used to manage U.S. Power's assets are presented on a net basis in Power revenues. The unrealized gains and losses from financial derivatives included in revenue are excluded to arrive at Comparable EBITDA.
2 Includes the cost of fuel consumed in generation.

Sales volumes and plant availability

(unaudited)	three months ended March 31 2016	2015
Physical sales volumes (GWh)		
Supply		
Generation[1]	**2,280**	914
Purchased	**4,748**	4,425
	7,028	5,339
Plant availability[2,3]	**71%**	61%

1 Increase primarily due to Ironwood acquisition.
2 The percentage of time the plant was available to generate power, regardless of whether it was running.
3 Plant availability was lower in the three months ended March 31, 2015 than the same period in 2016 due to an unplanned outage at the Ravenswood facility from September 2014 to May 2015.

U.S. Power - other information

(unaudited)	three months ended March 31 2016	2015
Average Spot Power Prices (US$ per MWh)		
New England[1]	**30**	85
New York[2]	**28**	72
PJM[3]	**21**	n/a
Average New York[2] Spot Capacity Prices (US$ per KW-M)	**5.83**	8.34

1 New England ISO all hours Mass Hub price.
2 Zone J market in New York City where the Ravenswood plant operates.
3 The METED Zone price in Pennsylvania where the Ironwood plant operates. Average price for 2016 is from February 1 to March 31, 2016.

Comparable EBITDA for U.S. Power decreased US$56 million for the three months ended March 31, 2016 compared to the same period in 2015 primarily due to the net effect of:

- lower margins on sales to wholesale, commercial and industrial customers in both the New England and PJM markets
- lower realized power prices at our facilities in New York and New England, partially offset by lower fuel costs and higher generation volumes
- lower capacity revenues at Ravenswood due to lower realized capacity prices in New York and the impact of lower availability at the facility, partially offset by insurance recoveries, net of deductibles
- higher earnings due to our acquisition of the Ironwood power plant on February 1, 2016.

Wholesale electricity prices in New York and New England were significantly lower for the three months ended March 31, 2016 compared to the same period in 2015 primarily due to unseasonably warm weather in 2016. In New England and New York City, spot power prices for the three months ended March 31, 2016 were 65 and 61 per cent lower, respectively, compared to the same period in 2015. Both markets have also experienced lower natural gas commodity prices throughout 2016 compared to 2015.

Lower margins on sales to wholesale, commercial and industrial customers in both the PJM and New England markets resulted in significantly lower earnings for the three months ended March 31, 2016 compared to the same period in 2015. Although we have expanded our customer base in the PJM market, significantly lower realized power prices and mild weather have resulted in lower margins in our wholesale business.

Average New York Zone J spot capacity prices were approximately 30 per cent lower for the three months ended March 31, 2016 compared to the same period in 2015. The decrease in spot prices and the offsetting impact of hedging activities resulted in lower realized capacity prices in New York. This was primarily due to increased available operational supply in New York City's Zone J market. The impact of lower capacity prices was partially offset by capacity revenues earned by our Ironwood power plant acquired in February 2016.

Capacity revenues were also negatively impacted by a unit outage from September 2014 to May 2015 at Ravenswood. The calculation used by the NYISO to determine the capacity volume for which a generator is compensated utilizes a rolling average forced outage rate. As a result of this methodology, outages impact capacity volumes and associated revenues on a lagged basis. Accordingly, capacity revenues for the three months ended March 31, 2016 were negatively impacted compared to the same period in 2015. The outage continues to be included in the rolling average forced outage rate. Insurance recoveries for this event were received and have been recognized in capacity revenues to offset amounts lost during the three months ended March 31, 2016. As a result of these insurance recoveries, the Unit 30 unplanned outage is not expected to have a significant impact on our earnings although the recording of earnings has not coincided with lost revenues due to timing of the insurance proceeds.

Physical generation volumes were higher for the three months ended March 31, 2016 compared to the same period in 2015 due to our acquisition of the Ironwood power plant and higher generation at our Ravenswood and Hydro facilities. Physical purchased volumes sold to wholesale, commercial and industrial customers were higher for the three months ended March 31, 2016 compared to the same period in 2015 as we have expanded our customer base in the PJM market.

As at March 31, 2016, approximately 6,100 GWh or 70 per cent of U.S. Power's planned generation was contracted for the remainder of 2016 and 3,900 GWh or 39 per cent for 2017. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets. Power sales fluctuate based on customer usage.

U.S. Power results for 2016 will be dependent on the timing of the previously announced monetization of the U.S. Northeast power assets. Nevertheless, operating results for the full year in 2016 are expected to be lower than our

Outlook in our 2015 Annual Report due to lower commodity prices experienced in the first quarter of 2016 and forecast for the remainder of the year.

NATURAL GAS STORAGE AND OTHER

Comparable EBITDA increased by $6 million for three months ended March 31, 2016 compared to the same period in 2015 mainly due to increased storage revenues as a result of higher realized natural gas storage price spreads.

The full year 2016 results are expected to be higher compared to 2015 due to the lack of seasonal winter weather conditions, excess natural gas supply and resulting increase in natural gas storage price spreads which have provided the opportunity to hedge available storage capacity at higher values than originally expected in the original Outlook in our 2015 Annual Report.

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented losses (the equivalent GAAP measure). Certain costs previously reported in our Corporate segment are now being reported within the business segments as a result of our 2015 business transformation initiative. 2015 results have been restated to reflect this change.

	three months ended March 31	
(unaudited - millions of $)	**2016**	**2015**
Comparable EBITDA	**(25)**	(24)
Depreciation and amortization	**(9)**	(7)
Comparable EBIT	**(34)**	(31)
Specific item:		
Acquisition costs - Columbia Pipeline Group	**(26)**	—
Segmented losses	**(60)**	(31)

Corporate segmented losses in 2016 increased by $29 million compared to 2015 due to a charge of $26 million relating to costs associated with the acquisition of Columbia. This amount has been excluded from our calculation of comparable EBIT.

Interest Expense

	three months ended March 31	
(unaudited - millions of $)	**2016**	**2015**
Comparable interest on long-term debt (including interest on junior subordinated notes)		
Canadian-dollar denominated	**(111)**	(109)
U.S. dollar-denominated (US$)	**(246)**	(218)
Foreign exchange impact	**(85)**	(48)
	(442)	(375)
Other interest and amortization expense	**(19)**	(13)
Capitalized interest	**41**	70
Comparable interest expense	**(420)**	(318)
Specific items[1]	**—**	—
Interest expense	**(420)**	(318)

1 There were no specific items in the periods.

Comparable interest expense increased by $102 million for the three months ended March 31, 2016 compared to the same period in 2015 due to the net effect of:

- higher interest expense as a result of long-term debt issuances in 2015 and first quarter 2016, partially offset by Canadian and U.S. dollar-denominated debt maturities
- a stronger U.S. dollar and its effect on the foreign exchange impact on interest expense related to U.S. dollar-denominated debt
- lower capitalized interest on Keystone XL and related projects following the November 6, 2015 denial of a U.S. Presidential Permit, partially offset by higher capitalized interest on LNG projects and the Napanee power generating facility.

Interest income and other

	three months ended March 31	
(unaudited - millions of $)	**2016**	**2015**
Comparable interest income and other		
AFUDC	**101**	58
Other	**47**	(43)
	148	15
Specific item (pre-tax):		
Risk management activities	**53**	(29)
Interest income and other	**201**	(14)

Comparable interest income and other increased by $133 million for the three months ended March 31, 2016 compared to the same period in 2015 as a net result of:

- realized gains in 2016 compared to realized losses in 2015 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar denominated income
- increased AFUDC related to our rate-regulated projects including Mexico pipelines, NGTL's expansion and Energy East.

Income tax expense

	three months ended March 31	
(unaudited - millions of $)	**2016**	**2015**
Comparable income tax expense	**(180)**	(247)
Specific items:		
Alberta PPA terminations	**64**	—
Keystone XL asset costs	**4**	—
TC Offshore loss on sale	**1**	—
Risk management activities	**41**	40
Income tax expense	**(70)**	(207)

Comparable income tax expense decreased by $67 million for the three months ended March 31, 2016 compared to the same period in 2015. The decrease was mainly the result of lower pre-tax earnings in 2016 compared to 2015, changes in the proportion of income earned between Canadian and foreign jurisdictions and by lower flow-through taxes in 2016 on Canadian regulated pipelines.

Net income attributable to non-controlling interests

	three months ended March 31	
(unaudited - millions of $)	**2016**	**2015**
Net income attributable to non-controlling interests	**(80)**	(59)

Net income attributable to non-controlling interests increased by $21 million for the three months ended March 31, 2016 compared to the same period in 2015 primarily due to the sale of our 30 per cent direct interest in GTN in April 2015 and 49.9 per cent direct interest in PNGTS in January 2016 to TC PipeLines, LP and the impact of a stronger U.S. dollar on the Canadian dollar equivalent earnings from TC PipeLines, LP.

Preferred share dividends

	three months ended March 31	
(unaudited - millions of $)	**2016**	**2015**
Preferred share dividends	**(22)**	(23)

Recent developments

ACQUISITION OF COLUMBIA PIPELINE GROUP, INC.

Acquisition

On March 17, 2016, we entered into an agreement and plan of merger to acquire Columbia. Columbia owns one of the largest interstate natural gas pipeline systems in the U.S., providing transportation, storage and related services to a variety of customers in the northeast, mid-west, mid-Atlantic and Gulf Coast regions. Its assets include Columbia Gas Transmission, which operates approximately 18,000 km (11,300 miles) of pipelines and 620 Bcf in total operational capacity, with approximately 286 Bcf of working gas capacity in the Marcellus and Utica shale production areas, and Columbia Gulf Transmission, an approximate 5,400-km (3,300-mile) pipeline system that extends from Appalachia to the Gulf Coast.

Columbia stockholders will receive US$25.50 per share which represents an aggregate transaction value of approximately US$13 billion including the assumption of approximately US$2.8 billion of debt. We expect to finance the US$10.2 billion cash component of the acquisition through an offering of subscription receipts, which closed on April 1, 2016 for gross proceeds of approximately $4.4 billion, the planned monetization of our U.S. Northeast power assets and a minority interest in our Mexican natural gas pipeline business, and existing cash on hand. A syndicate of lenders have committed to provide debt bridge facilities in the amount of US$6.9 billion which will be utilized pending the realization of proceeds from the planned monetization of assets outlined above. We expect the acquisition, net of financing and the planned asset monetization, to be accretive to earnings per share in the first full year of ownership. We are targeting US$250 million of annual cost, revenue and financing benefits. See the Financial condition section for more information about the subscription receipts which will be automatically exchanged into common shares upon the closing of the acquisition.

We and Columbia each filed a Hart-Scott-Rodino Notification with the U.S. Federal Trade Commission on April 4, 2016. We also both submitted a filing with the Committee on Foreign Investment in the United States which was accepted on April 13, 2016. The special meeting for Columbia stockholders to approve the transaction is scheduled for June 22, 2016.

Two class action lawsuits seeking to enjoin the Columbia acquisition have been filed in the Delaware Court of Chancery by purported stockholders of Columbia on their own behalf and on behalf of all other stockholders of Columbia. The first, filed on March 30, 2016, names Columbia, the TransCanada entities that are parties to the merger agreement with Columbia, and each member of Columbia's Board of Directors. The second action was filed on April 7, 2016 against each member of Columbia's Board of Directors. We are not named as a defendant. Our view is that there is no merit to the allegations in these actions.

We expect the acquisition to close in second half 2016 subject to the shareholder and regulatory approvals outlined above.

Monetization of U.S. Northeast power assets and a minority interest in Mexican pipelines

We expect to partially finance the acquisition of Columbia through the monetization of our U.S. Northeast power assets and a minority interest in our Mexican natural gas pipeline business.

NATURAL GAS PIPELINES

Canadian Regulated Pipelines

NGTL System

In first quarter 2016, we placed approximately $100 million of facilities in service with another $600 million currently under construction. The NGTL System continues to develop approximately $7.3 billion of new supply and demand facilities. We have approximately $2.5 billion of facilities that have received regulatory approval and a further approximately $1.9 billion of facilities which are currently under regulatory review. Applications for approval to construct and operate an additional $2.9 billion of facilities have yet to be filed.

Included in our capital program described above is the recently announced 2018 expansion of a further $600 million of facilities required on the NGTL System. The 2018 expansion includes multiple projects totaling approximately 88 km (55 miles) of 20- to 48-inch diameter pipeline, one new compressor, approximately 35 new and expanded meter stations and other associated facilities. Applications to construct and operate the various components of the 2018 expansion program will be filed with the NEB in late 2016 and early 2017. Subject to regulatory approvals, construction is expected to start in 2017, with all facilities expected to be in service in 2018.

North Montney Mainline

On March 28, 2016, we filed a request with the NEB for a one year extension to the June 10, 2016 sunset clause in the North Montney Mainline (NMML) project Certificate of Public Convenience and Necessity (CPCN). A pre-construction CPCN condition requires that Petronas make a positive FID on the proposed Pacific Northwest LNG Project. Petronas is waiting on completion of the federal environmental assessment process for the LNG Project before it makes an FID. On March 18, 2016, the federal government extended the legislated time-line for that process by three months and is seeking additional information on the project. The requested extension of the NMML CPCN sunset clause ensures our regulatory approvals remain valid and do not expire pending an FID.

2016-2017 NGTL Revenue Requirement Settlement

On April 7, 2016, the NEB approved the NGTL revenue requirement settlement application that was filed in December 2015, subject to certain reporting requirements. The settlement includes a ROE of 10.1 per cent on a deemed common equity of 40 per cent, continuation of 2015 depreciation rates, a mechanism for sharing variances above and below a fixed annual operating, maintenance and administration cost amount and flow-through treatment of all other costs.

U.S. Pipelines

Iroquois Gas Transmission System

On March 31, 2016, we closed the acquisition of an additional 4.87 per cent interest in Iroquois Gas Transmission System, L.P. (Iroquois) from one of our partners for US$54 million. Following this acquisition, our ownership interest in Iroquois increased to 49.35 per cent. We are also expecting to close an additional 0.65 per cent interest from another partner in second quarter 2016 that will increase our overall ownership interest to 50 per cent.

ANR Section 4 Rate Case

On January 29, 2016, ANR filed a Section 4 Rate Case with the FERC that requests an increase to ANR's maximum transportation rates. On February 29, 2016, the FERC issued an order that accepted and suspended ANR’s rate and tariff changes to become effective August 1, 2016, subject to refund and the outcome of a hearing. In addition, on March 23, 2016, the FERC established a procedural schedule for the hearing and appointed a settlement judge to assist the parties in their settlement negotiations. The hearing is currently scheduled for early February 2017 and settlement conferences will be held throughout the process.

TC Offshore

Effective March 31, 2016, we completed the sale of TC Offshore LLC to a third party. The sale includes 535 miles (860 km) of natural gas gathering and transmission pipeline, seven offshore platforms and other facilities.

Mexico

Tula-Villa de Reyes Pipeline

On April 11, 2016, we announced we were awarded the contract to build, own and operate the Tula-Villa de Reyes pipeline in Mexico. Construction of the pipeline is supported by a 25-year natural gas transportation service contract for 886 million cubic feet per day with the CFE. We expect to invest approximately US$550 million on a 36-inch diameter, 420-km (261-mile) pipeline with an anticipated in-service date of early 2018. The pipeline will begin in Tula in the state of Hidalgo, and terminate in Villa de Reyes in the state of San Luis Potosí, transporting natural gas to power generation facilities in the central region of the country. The project will interconnect with our Tamazunchale and Tuxpan-Tula pipelines as well as with other transporters in the region.

LNG Pipeline Projects

Prince Rupert Gas Transmission

We are continuing engagement with Aboriginal groups and have now announced project agreements with eleven First Nation groups along the pipeline route which outline financial and other benefits and commitments that will be provided to each First Nation group for as long as the project is in service.

Coastal GasLink

The LNG Canada joint venture participants anticipate reaching a final investment decision on their Kitimat-based LNG project in late 2016. Based on the current schedule, preliminary construction work could begin in January 2017.

We continue to engage with all First Nations and stakeholders along the pipeline route. At the end of 2015, we had reached long-term project agreements with eleven of the twenty First Nations with claims to traditional and treaty territory traversed by the project. We continue to negotiate with the remaining First Nations and expect to execute additional project agreements in 2016.

LIQUIDS PIPELINES

Keystone Pipeline

On April 2, 2016, we shut down the Keystone pipeline after a leak was detected along the pipeline right-of-way in Hutchinson County, South Dakota. We reported the total volume of the release of 400 barrels to the National Response Center and the Pipeline and Hazardous Materials Safety and Administration (PHMSA). Temporary repairs were completed on April 9, 2016, and the Keystone pipeline was restarted on April 10, 2016. Permanent repairs and remaining restoration work at site is planned for May 2016 with further investigative activities and corrective measures required by PHMSA planned in 2016.

This shutdown is not expected to have a significant impact on our 2016 earnings.

Energy East Pipeline

On March 1, 2016, the Province of Québec filed a court action seeking an injunction to compel the Energy East Pipeline to comply with the province's environmental regulations. On March 30, 2016, the Québec Superior Court joined the injunction action led by the Province of Québec with the prior action led by Québec Environmental Law Centre / Centre québécois du droit de l'environnement (CQDE), which sought a declaration to compel Energy East to submit to the mandatory provincial environmental review process. As a result of communication with the Ministère du Développement et la Lutte contre les changements climatiques, on April 22, 2016, we filed a project review engaging an environmental assessment under the Environmental Quality Act (Québec) according to an agreed upon schedule for key steps in that process. This process is in addition to environmental assessment required under the National Energy Board Act and the Canadian Environmental Assessment Act, 2012. The Attorney General for Québec has agreed to suspend its litigation against TransCanada and Energy East and to withdraw it once the provincial environmental assessment process has been completed. Whether the CQDE, as the other applicant to the litigation, will similarly seek to suspend the action is not known at this time. We do not anticipate this will result in a delay with regard to the NEB's review process.

On March 17, 2016, the first phase of Energy East public hearings for the voluntary Québec le Bureau d'audiences publiques sur l'environnement (BAPE) process was completed. The voluntary BAPE hearing process is intended to inform the Province of Québec in its participation in the federal process and provides project information to the public. A second phase, consisting of a series of public input sessions, has been suspended as it has been replaced with the environmental assessment as described above.

On March 21, 2016, the NEB approved the Table of Contents for the consolidated application. Filing of the consolidated application is targeted for mid-May.

Liquids Marketing Business

The liquids marketing business began operations in 2016 to generate incremental revenues through the purchase and concurrent sale of crude oil. Derivative instruments are used to fix a portion of the variable price exposures that arise from physical liquids transactions. To settle purchase and sale activities, we will enter into contracts for pipeline and terminal capacity, including space on our assets.

ENERGY

Alberta PPAs

On March 7, 2016, we issued notice to the Balancing Pool to terminate our Alberta PPAs. The arrangements contain a provision that permits the PPA buyers to terminate the PPAs if there is a change in the law that makes the arrangements unprofitable or more unprofitable. This termination affects the Sheerness, Sundance A and Sundance B PPAs. Unprofitable market conditions are expected to continue as costs related to carbon emissions have increased and are forecast to continue to increase over the remaining term of the PPA agreements. We expect the termination will improve cash flow and comparable earnings in the near term.

As a result of our decision to terminate the PPAs, we have recorded a non-cash impairment charge of $240 million before tax ($176 million after tax) comprised of $211 million before tax ($155 million after tax) related to the carrying value of our Sundance A and Sheerness PPAs and $29 million before tax ($21 million after tax) on our equity investment of ASTC Power Partnership which holds the Sundance B PPA.

Carbon tax

In February 2016, the Government of Ontario released enabling legislation and draft regulations for its proposed cap and trade program which would set an annual province-wide cap on greenhouse gas emissions beginning in 2017 and introduce a market to administer the purchase and trading of emissions allowances. The program would cover most emission sources in the province, including emissions from the electricity generation sector.

In parallel with this, the IESO has launched their own consultation process to determine what contractual amendments will be proposed to address the change in deemed operating costs for emitting generators and the resulting deemed energy margin derived from the market. We anticipate that the associated costs with the purchase of greenhouse gas emission allowances will be recovered from the IESO market and that our contracts with the IESO will be amended to preserve the economic value.

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 cash flow from our operations, access to capital markets, monetization of assets including dropdowns to TC PipeLines, LP, cash on hand and substantial committed credit facilities.

CASH PROVIDED BY OPERATING ACTIVITIES

	three months ended March 31	
(unaudited - millions of $)	**2016**	**2015**
Funds generated from operations[1]	**1,125**	1,153
Increase in operating working capital	**(80)**	(393)
Net cash provided by operations	**1,045**	760

1 See the non-GAAP measures section in this MD&A for further discussion of funds generated from operations.

At March 31, 2016, our current assets were $4.1 billion and current liabilities were $7.1 billion, leaving us with a working capital deficit of $3.0 billion compared to $3.4 billion at December 31, 2015. This working capital deficiency is considered to be in the normal course of business and is managed through:

- our ability to generate cash flow from operations
- our access to capital markets
- approximately $6.9 billion of unutilized, unsecured committed credit facilities.

COMPARABLE DISTRIBUTABLE CASH FLOW

	three months ended March 31	
(unaudited - millions of $)	**2016**	**2015**
Net cash provided by operations	**1,045**	760
Increase in operating working capital	**80**	393
Funds generated from operations	**1,125**	1,153
Dividends on preferred shares	**(23)**	(22)
Distributions paid to non-controlling interests	**(62)**	(54)
Distributions received in excess of equity earnings	**88**	46
Maintenance capital expenditures including equity investments	**(190)**	(167)
Distributable cash flow	**938**	956
Specific items (net of tax):		
Acquisition costs - Columbia Pipeline Group	**26**	—
Keystone XL asset costs	**6**	—
Comparable distributable cash flow	**970**	956
Comparable distributable cash flow per common share	**$1.38**	$1.35

Comparable distributable cash flow, a non-GAAP measure, helps us assess the cash available to common shareholders before capital allocation. See our non-GAAP measures section for more information.

Maintenance capital expenditures on our Canadian regulated natural gas pipelines were $55 million and $52 million in first quarter 2016 and 2015, respectively, which contributed to their respective rate bases and net income.

CASH USED IN INVESTING ACTIVITIES

	three months ended March 31	
(unaudited - millions of $)	**2016**	**2015**
Capital spending		
Capital expenditures	**(836)**	(806)
Capital projects in development	**(67)**	(163)
	(903)	(969)
Contributions to equity investments	**(170)**	(93)
Acquisitions, net of cash acquired	**(995)**	—
Proceeds from sale of assets, net of transaction costs	**6**	—
Distributions received in excess of equity earnings	**88**	46
Deferred amounts and other	**—**	179
Net cash used in investing activities	**(1,974)**	(837)

Capital expenditures in 2016 were primarily related to:

- expansion of the NGTL System
- construction of Mexico pipelines
- expansion of the ANR pipeline
- construction of the Northern Courier pipeline
- expansion of the Canadian Mainline
- construction of the Napanee power generating facility.

Costs incurred on capital projects under development primarily relate to the Energy East Pipeline and LNG pipeline projects.

Contributions to equity investments have increased in 2016 compared to 2015 primarily due to our investments in Grand Rapids and Bruce Power.

On February 1, 2016, we acquired the Ironwood natural gas fired, combined cycle power plant in Lebanon, Pennsylvania, with a capacity of 778 MW, for US$657 million in cash before post-acquisition adjustments.

On March 31, 2016, we acquired an additional 4.87 per cent interest in Iroquois Gas Transmission System LP (Iroquois) for an aggregate purchase price of US$54 million. As a result of this acquisition, our interest in Iroquois has increased to 49.35 per cent.

The increase in distributions received in excess of equity earnings is primarily due to distributions from Bruce Power.

CASH PROVIDED BY FINANCING ACTIVITIES

	three months ended March 31	
(unaudited - millions of $)	**2016**	**2015**
Notes payable issued, net	**1,176**	279
Long-term debt issued, net of issue costs	**1,992**	2,277
Long-term debt repaid	**(1,357)**	(1,016)
Dividends and distributions paid	**(450)**	(417)
Common shares issued, net of issue costs	**3**	10
Common shares repurchased	**(14)**	—
Preferred shares issued, net of issue costs	**—**	243
Partnership units of subsidiary issued, net of issue costs	**24**	4
Net cash provided by financing activities	**1,374**	1,380

LONG-TERM DEBT ISSUED

(unaudited - millions of $) Company	Issue date	Type	Maturity date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	January 2016	Senior Unsecured Notes	January 2019	US $400	3.125%
	January 2016	Senior Unsecured Notes	January 2026	US $850	4.875%

LONG-TERM DEBT RETIRED

(unaudited - millions of $) Company	Retirement date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	January 2016	Senior Unsecured Notes	US $750	0.75%
NOVA GAS TRANSMISSION LTD.				
	February 2016	Debentures	$225	12.2%

COMMON SHARES REPURCHASED

In November 2015, the TSX approved our normal course issuer bid (NCIB), which allows for the repurchase and cancellation of up to 21.3 million common shares, representing three per cent of our issued and outstanding common shares, between November 23, 2015 and November 22, 2016, at prevailing market prices plus brokerage fees, or such other prices as may be permitted by the TSX.

The following table provides the information related to shares repurchased in 2016 under the NCIB:

at April 28, 2016 (millions of $, except number of common shares and per share data)	
Number of common shares repurchased[1]	305,407
Weighted-average price per common share[2]	$44.90
Amount of repurchase	$13.7

1 Includes repurchases of common shares pursuant to private agreements with third-parties.

2 Includes brokerage fees.

SUBSCRIPTION RECEIPTS

On April 1, 2016, we issued 96.6 million subscription receipts to partially fund the Columbia Pipeline Group acquisition at a price of $45.75 each for total proceeds of approximately $4.4 billion. Each subscription receipt entitles the holder to automatically receive one common share upon closing of the Columbia acquisition. While the subscription receipts remain outstanding, holders will be entitled to receive cash payments per subscription receipt that are equal to dividends declared on each common share, with the first payment on April 29, 2016 for holders of record at close of business on April 15, 2016. The second dividend equivalent payment will be made to holders of record at the close of business on June 30, 2016, provided that the acquisition has not closed or the Merger Agreement with Columbia has not been terminated. If the Merger Agreement is terminated after the common share dividend declaration date of April 29, 2016 but before the common share dividend record date of June 30, 2016, subscription receipt holders of record on the termination date shall receive a pro-rata payment of the dividend as the dividend equivalent payment. If the Merger Agreement has not closed by March 17, 2017, we will be required to make a termination payment equal to the aggregate issue price plus any unpaid dividend equivalent payments owing to the holders.

The gross proceeds from the sale of the subscription receipts, less any amounts used for dividend equivalent payments, will be held in escrow until the acquisition close date and will be recorded as restricted cash.

PREFERRED SHARE ISSUANCE AND CONVERSION

On February 1, 2016, holders of 1.3 million Series 5 cumulative redeemable first preferred shares exercised their option to convert to Series 6 cumulative redeemable first preferred shares and receive quarterly floating rate cumulative dividends at an annual rate equal to the applicable 90-day Government of Canada treasury bill rate plus 1.54 per cent which will reset every quarter going forward. The fixed dividend rate on the remaining Series 5 preferred shares was reset for five years at 2.263 per cent per annum. Such rate will reset every five years.

On April 20, 2016, we completed a public offering of 20 million Series 13 cumulative redeemable first preferred shares at $25 per share resulting in gross proceeds of $500 million. The Series 13 preferred shareholders will have the right to convert their Series 13 preferred shares into Series 14 cumulative redeemable first preferred shares on May 31, 2021 and on the last business day of May of every fifth year thereafter. The holders of Series 14 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at an annual rate equal to the sum of the applicable 90-day Government of Canada treasury bill rate plus 4.69 per cent. The fixed dividend rate on the Series 13 preferred shares was set for five years at 5.5 per cent per annum. The dividend rate will reset every five years at a rate equal to the sum of the applicable five-year Government of Canada bond yield plus 4.69 per cent but not less than 5.5 per cent per annum.

The following table summarizes the impact of the 2016 conversion and issuance of preferred shares discussed above:

(unaudited)	**Number of shares issued and outstanding** (thousands)	**Current yield**[1]	**Annual dividend per share**[1]	**Redemption price per share**[2]	**Redemption and conversion option date**[1,2]	**Right to convert into**
Cumulative first preferred shares						
Series 5	12,714	2.263%	$0.56575	$25.00	January 30, 2021	Series 6
Series 6	1,286	Floating[3]	Floating	$25.00	January 30, 2021	Series 5
Series 13	20,000	5.5%	$1.375	$25.00	May 31, 2021	Series 14

1 Holders of the cumulative redeemable first preferred shares set out in this table are entitled to receive a fixed cumulative quarterly preferred dividend, as and when declared by the Board, with the exception of Series 6 preferred shares. The holders of Series 6 preferred shares are entitled to receive a quarterly floating rate cumulative preferred dividend as and when declared by the Board.

2 We may, at our option, redeem all or a portion of the outstanding preferred shares for the redemption price per share, plus all accrued and unpaid dividends, on the redemption option date and on every fifth anniversary date thereafter. In addition, Series 6 preferred shares are redeemable by us at any time other than on a designated redemption option date for $25.50 per share plus all accrued and unpaid dividends on such redemption date.

3 Commencing March 31, 2016, the floating quarterly dividend rate for the Series 6 preferred shares is 2.002 per cent and will reset every quarter going forward.

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

Since January 1, 2016, 0.8 million common units were issued under the TC PipeLines, LP ATM program generating net proceeds of approximately US$39 million. Our ownership interest in TC PipeLines, LP decreased as a result of issuances under the ATM program.

DIVIDENDS

On April 28, 2016, we declared quarterly dividends as follows:

Quarterly dividend on our common shares
$0.565 per share
Payable on July 29, 2016 to shareholders of record at the close of business on June 30, 2016

Quarterly dividend equivalent payment on our subscription receipts[1]
$0.565 per subscription receipt
Payable on April 29, 2016 to holders of record at the close of business on April 15, 2016
Payable on July 29, 2016 to holders of record at the close of business on June 30, 2016[2]

1 Dividend equivalents are a term of the subscription receipts and are not declared by the Board.
2 If the Merger Agreement with Columbia is terminated after the common share dividend declaration date of April 29, 2016 but before the common share dividend record date of June 30, 2016, subscription receipt holders of record on the termination date shall receive a pro-rata payment of the dividend as the dividend equivalent payment.

Quarterly dividends on our preferred shares	
Series 1	$0.204125
Series 2	$0.14806148
Series 3	$0.1345
Series 4	$0.10828005
Payable on June 30, 2016 to shareholders of record at the close of business on May 31, 2016	
Series 5	$0.14143750
Series 6	$0.12444126
Series 7	$0.25
Series 9	$0.265625
Payable on August 2, 2016 to shareholders of record at the close of business on June 30, 2016	
Series 11	$0.2375
Series 13	$0.154
Payable on May 31, 2016 to shareholders of record at the close of business on May 12, 2016	

SHARE INFORMATION

as at April 25, 2016		
Common shares	**Issued and outstanding**	
	702 million	
Preferred shares	**Issued and outstanding**	**Convertible to**
Series 1	9.5 million	Series 2 preferred shares
Series 2	12.5 million	Series 1 preferred shares
Series 3	8.5 million	Series 4 preferred shares
Series 4	5.5 million	Series 3 preferred shares
Series 5	12.7 million	Series 6 preferred shares
Series 6	1.3 million	Series 5 preferred shares
Series 7	24 million	Series 8 preferred shares
Series 9	18 million	Series 10 preferred shares
Series 11	10 million	Series 12 preferred shares
Series 13	20 million	Series 14 preferred shares
Options to buy common shares	**Outstanding**	**Exercisable**
	12 million	7 million
Subscription receipts	**Outstanding**	**Convertible to**
	96.6 million	96.6 million common shares

CREDIT FACILITIES

We use committed revolving credit facilities to support our commercial paper programs and, along with demand facilities, for general corporate purposes including issuing letters of credit as well as providing additional liquidity including the acquisition of Columbia Pipelines.

At April 28, 2016, we had approximately $17.6 billion in unsecured credit facilities, including:

Amount	Unused capacity	Subsidiary	Description and use	Matures
$3.0 billion	$3.0 billion	TCPL	Committed, syndicated, revolving, extendible TCPL credit facility that supports TCPL's Canadian commercial paper program	December 2020
US$5.2 billion	US$5.2 billion	TCPL	Committed, syndicated, senior unsecured asset sale bridge term loan commitment that supports the acquisition of Columbia[1]	24 months from acquisition closing date
US$1.0 billion	US$1.0 billion	TCPL	Committed, syndicated, revolving, extendible TCPL credit facility that supports TCPL's U.S. commercial paper program	December 2016
US$1.7 billion	US$1.7 billion	TCPL USA	Committed, syndicated, senior unsecured asset sale bridge term loan commitment that supports the acquisition of Columbia[1]	24 months from acquisition closing date
US$0.5 billion	US$0.5 billion	TCPL USA	Committed, syndicated, revolving, extendible TCPL USA credit facility that is used for TCPL USA general corporate purposes	December 2016
US$1.5 billion	US$1.5 billion	TAIL/TCPM	Committed, syndicated, revolving, extendible credit facility that supports the joint TAIL/TCPM commercial paper program in the U.S.	December 2016
$1.7 billion	$0.6 billion	TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity	Demand

1 Proceeds from asset sales must be used to repay these facilities. See Recent developments section for more information.

At April 28, 2016, our operated affiliates had an additional $0.7 billion of undrawn capacity on committed credit facilities.

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

CONTRACTUAL OBLIGATIONS

In addition to our commitment to acquire Columbia, our capital commitments increased by approximately $0.2 billion since December 31, 2015 as a result of the new commitments for the Tuxpan-Tula natural gas pipeline partially offset by decreased commitments on Grand Rapids and Napanee. Our other purchase obligations are consistent with the amounts reported at December 31, 2015.

Our commitments at December 31, 2015 included fixed payments net of sublease receipts for Alberta PPAs. With the March 7, 2016 notice to terminate our Sheerness, Sundance A and Sundance B PPAs, our future obligations from December 31, 2015 have decreased as follows: 2016 - $195 million, 2017 - $200 million, 2018 - $141 million, 2019 - $138 million and 2020 - $115 million. There were no other material changes to our contractual obligations in first quarter 2016 or to payments due in the next five years or after. See the MD&A in our 2015 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.

Our liquids marketing business began its operations in the first quarter of 2016. It enters into short-term or long-term pipeline and storage terminal capacity contracts, primarily on the Company's assets, increasing the utilization of those assets and earning the market value of the capacity. Derivative instruments are used to fix a portion of the variable price exposures that arise from physical liquids transactions.

See our 2015 Annual Report for more information about the risks we face in our business. Our risks have not changed substantially since December 31, 2015.

LIQUIDITY RISK

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

COUNTERPARTY CREDIT RISK

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

- accounts receivable
- portfolio investments
- the fair value of derivative assets
- cash and notes receivable.

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At March 31, 2016, we had no significant credit losses and no significant amounts past due or impaired. We had a credit risk concentration of $191 million (US$147 million) at March 31, 2016 with one counterparty (December 31, 2015 - $248 million (US$179 million)). This amount is secured by a guarantee from the counterparty's parent company and is expected to be fully collectible.

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

FOREIGN EXCHANGE AND INTEREST RATE RISK

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

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

Average exchange rate - U.S. to Canadian dollars

three months ended March 31, 2016	**1.35**
three months ended March 31, 2015	1.24

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

Significant U.S. dollar-denominated amounts

	three months ended March 31	
(unaudited - millions of US$)	**2016**	**2015**
U.S. and International Natural Gas Pipelines comparable EBIT	**243**	239
U.S. Liquids Pipelines comparable EBIT	**130**	147
U.S. Power comparable EBIT	**46**	105
Interest on U.S. dollar-denominated long-term debt	**(246)**	(218)
Capitalized interest on U.S. dollar-denominated capital expenditures	**7**	31
U.S. non-controlling interests	**(60)**	(48)
	120	256

Derivatives designated as a net investment hedge

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

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

	March 31, 2016		December 31, 2015	
(unaudited - millions of Canadian $, unless noted otherwise)	Fair value[1]	Notional or principal amount	Fair value[1]	Notional or principal amount
Asset/(liability)				
U.S. dollar cross-currency interest rate swaps (maturing 2016 to 2019)[2]	**(573)**	**US 2,900**	(730)	US 3,150
U.S. dollar foreign exchange forward contracts (maturing 2016 to 2017)	**(58)**	**US 700**	50	US 1,800
	(631)	**US 3,600**	(680)	US 4,950

1 Fair values equal carrying values.
2 In the three months ended March 31, 2016, net realized gains of $2 million (2015 - gains of $3 million) related to the interest component of cross-currency swaps settlements are included in interest expense.

U.S. dollar-denominated debt designated as a net investment hedge

(unaudited - millions of Canadian $, unless noted otherwise)	March 31, 2016	December 31, 2015
Notional amount	**19,100 (US 14,700)**	23,100 (US 16,700)
Fair value	**20,100 (US 15,500)**	23,800 (US 17,200)

FINANCIAL INSTRUMENTS

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

Derivative instruments

We use derivative instruments to reduce volatility associated with fluctuations in commodity prices, interest rates and foreign exchange rates. We apply hedge accounting to derivative instruments that qualify and are designated for hedge accounting treatment. The effective portion of the change in the fair value of hedging derivatives for cash flow hedges and hedges of our net investment in foreign operations are recorded in OCI in the period of change. Any ineffective portion is recognized in net income in the same financial category as the underlying transaction. The change in the fair value of derivative instruments that have been designated as fair value hedges are recorded in net income in interest income and other and interest expense.

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 the derivative instruments is as follows:

(unaudited - millions of $)	March 31, 2016	December 31, 2015
Other current assets	**556**	442
Intangible and other assets	**216**	168
Accounts payable and other	**(1,081)**	(926)
Other long-term liabilities	**(625)**	(625)
	(934)	(941)

Unrealized and realized (losses)/gains of derivative instruments

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

	three months ended March 31	
(unaudited - millions of $, pre-tax)	2016	2015
Derivative instruments held for trading[1,2]		
Amount of unrealized (losses)/gains in the period		
Commodities	**(67)**	(26)
Foreign exchange	**27**	(29)
Amount of realized (losses)/gains in the period		
Commodities	**(95)**	1
Foreign exchange	**44**	(43)
Derivative instruments in hedging relationships		
Amount of realized (losses)/gains in the period		
Commodities	**(73)**	16
Foreign exchange	**(63)**	—
Interest rate	**2**	2

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

2 Following the March 17, 2016 announcement of our intention to sell the U.S. Northeast power assets, a loss of $49 million and a gain of $7 million (2015 - nil) were recorded in net income relating to discontinued cash flow hedges where it was probable that the anticipated underlying transaction would not occur as a result of a future sale.

Derivatives in cash flow hedging relationships

The components of the condensed consolidated statement of OCI related to derivatives in cash flow hedging relationships is as follows:

	three months ended March 31	
(unaudited - millions of $, pre-tax)	**2016**	**2015**
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Commodities	**(16)**	21
Foreign exchange	**(35)**	—
Interest rate	**(1)**	—
	(52)	21
Reclassification of gains on derivative instruments from AOCI to net income (effective portion)[1]		
Commodities[2]	**82**	69
Foreign exchange[3]	**34**	—
Interest rate[4]	**4**	4
	120	73
Losses on derivative instruments recognized in net income (ineffective portion)		
Commodities[2]	**(58)**	(63)
	(58)	(63)

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI.
2 Reported within revenues on the condensed consolidated statement of income.
3 Reported within interest income and other on the condensed consolidated statement of income.
4 Reported within interest expense on the condensed consolidated statement of income.

Credit risk related contingent features of derivative instruments

Derivatives often contain financial assurance provisions that may require us to provide collateral if a credit risk related contingent event occurs (for example, if our credit rating is downgraded to non-investment grade). We may also need to provide collateral if the fair value of our derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at March 31, 2016, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $42 million (December 31, 2015 – $32 million), with collateral provided in the normal course of business of nil (December 31, 2015 – nil). If the credit-risk-related contingent features in these agreements were triggered on March 31, 2016, we would have been required to provide additional collateral of $42 million (December 31, 2015 – $32 million) to our counterparties. We have sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Other information

CONTROLS AND PROCEDURES

Management, including our President and CEO and our CFO, evaluated the effectiveness of our disclosure controls and procedures as at March 31, 2016, as required by the Canadian securities regulatory authorities and by the SEC, and concluded that our disclosure controls and procedures are effective at a reasonable assurance level.

There were no changes in first quarter 2016 that had or are likely to have a material impact on our internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES AND ACCOUNTING POLICY CHANGES

When we prepare financial statements that conform with U.S. GAAP, we are required to make estimates and assumptions that affect the timing and amount we record for our assets, liabilities, revenues and expenses because these items may be affected by future events. We base the estimates and assumptions on the most current information available, using our best judgement. We also regularly assess the assets and liabilities themselves. You can find a summary of our critical accounting estimates in our 2015 Annual Report.

Our significant accounting policies have remained unchanged since December 31, 2015 other than described below. You can find a summary of our significant accounting policies in our 2015 Annual Report.

Changes in accounting policies for 2016

Extraordinary and unusual income statement items
In January 2015, the FASB issued new guidance on extraordinary and unusual income statement items. This update eliminates from GAAP the concept of extraordinary items. This new guidance was effective January 1, 2016, was applied prospectively and did not have a material impact on our consolidated financial statements.

Consolidation
In February 2015, the FASB issued new guidance on consolidation. This update requires that entities re-evaluate whether they should consolidate certain legal entities and eliminates the presumption that a general partner should consolidate a limited partnership. This new guidance was effective January 1, 2016, was applied retrospectively and did not result in any change to our consolidation conclusions. Disclosure requirements outlined in the new guidance are included in Note 13, Variable interest entities.

Imputation of interest
In April 2015, the FASB issued new guidance on simplifying the accounting for debt issuance costs. The amendments in this update require that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability consistent with debt discounts or premiums. This new guidance was effective January 1, 2016, was applied retrospectively and resulted in a reclassification of debt issuance costs previously recorded in Intangible and other assets to an offset of their respective debt liabilities on our consolidated balance sheet.

Business Combinations
In September 2015, the FASB issued guidance which intends to simplify the accounting measurement-period adjustments in business combinations. The amended guidance requires an acquirer to recognize adjustments to the provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. In the period the adjustment was determined, the guidance also requires the acquirer to record the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. This new guidance was effective January 1, 2016, was applied prospectively and did not have a material impact on our consolidated financial statements.

Future accounting changes

Revenue from contracts with customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. This guidance supersedes the current revenue recognition requirements and most industry-specific guidance. This new guidance requires that an entity recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In July 2015, the FASB deferred the effective date of this new standard to January 1, 2018, with early adoption not permitted before January 1, 2017. There are two methods in which the amendment can be applied: (1) retrospectively to each prior reporting period presented, or (2) retrospectively with the cumulative effect recognized at the date of initial application.

We are currently evaluating the impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Inventory

In July 2015, the FASB issued new guidance on simplifying the measurement of inventory. The amendments in this update specify that an entity should measure inventory within the scope of this update at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This new guidance is effective January 1, 2017 and will be applied prospectively. We do not expect the adoption of this new standard to have a material impact on our consolidated financial statements.

Financial Instruments

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

Leases

In February 2016, the FASB issued new guidance on leases. The new guidance requires lessees to recognize most leases, including operating leases, on the balance sheet as lease assets and lease liabilities. In addition, lessees will be required to reassess assumptions associated with existing leases as well as to provide expanded qualitative and quantitative disclosures. The new standard does not make extensive changes to lessor accounting. The new guidance is effective January 1, 2019 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.

Derivatives and Hedging

In March 2016, the FASB issued new guidance that clarifies the requirements for assessing whether contingent call or put options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. The new guidance requires only an assessment of the four-step decision sequence outlined in GAAP to determine whether the economic characteristics and risks of call or put options are clearly and closely related to the economic characteristics and risks. This new guidance is effective January 1, 2017 and we are currently evaluating the impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Equity Method Investments

In March 2016, the FASB issued new guidance that simplifies the transition to equity method accounting. The new guidance eliminates the requirement to retroactively apply the equity method of accounting when an increase in ownership interest in an investment qualifies for equity method accounting. This new guidance is effective January 1, 2017 and will be applied prospectively. We do not expect the adoption of this new standard to have a material impact on our consolidated financial statements.

Reconciliation of non-GAAP measures

	three months ended March 31	
(unaudited - millions of $, except per share amounts)	2016	2015
EBITDA	**1,097**	1,442
Alberta PPA terminations	**240**	—
Acquisition costs - Columbia Pipeline Group	**26**	—
Keystone XL asset costs	**10**	—
TC Offshore loss on sale	**4**	—
Risk management activities[1]	**125**	89
Comparable EBITDA	**1,502**	1,531
Depreciation and amortization	**(454)**	(434)
Comparable EBIT	**1,048**	1,097
Other income statement items		
Comparable interest expense	**(420)**	(318)
Comparable interest income and other	**148**	15
Comparable income tax expense	**(180)**	(247)
Net income attributable to non-controlling interests	**(80)**	(59)
Preferred share dividends	**(22)**	(23)
Comparable earnings	**494**	465
Specific items (net of tax):		
Alberta PPA terminations	**(176)**	—
Acquisition costs - Columbia Pipeline Group	**(26)**	—
Keystone XL asset costs	**(6)**	—
TC Offshore loss on sale	**(3)**	—
Risk management activities[1]	**(31)**	(78)
Net income attributable to common shares	**252**	387
Comparable interest income and other	**148**	15
Specific items:		
Risk management activities[1]	**53**	(29)
Interest income and other expense	**201**	(14)
Comparable income tax expense	**(180)**	(247)
Specific items:		
Alberta PPA terminations	**64**	—
Keystone XL asset costs	**4**	—
TC Offshore loss on sale	**1**	—
Risk management activities[1]	**41**	40
Income tax expense	**(70)**	(207)

(unaudited - millions of $, except per share amounts)	three months ended March 31 2016	 2015
Comparable earnings per common share	**$0.70**	$0.66
Specific items (net of tax):		
Alberta PPA terminations	**(0.25)**	—
Acquisition costs - Columbia Pipeline Group	**(0.04)**	—
Keystone XL asset costs	**(0.01)**	—
TC Offshore loss on sale	**—**	—
Risk management activities	**(0.04)**	(0.11)
Net income per common share	**$0.36**	$0.55

1

Risk management activities (unaudited - millions of $)	three months ended March 31 2016	 2015
Canadian Power	**(13)**	(22)
U.S. Power	**(115)**	(68)
Liquids	**(2)**	—
Natural Gas Storage	**5**	1
Foreign exchange	**53**	(29)
Income tax attributable to risk management activities	**41**	40
Total losses from risk management activities	**(31)**	(78)

Comparable EBITDA and EBIT by business segment

three months ended March 31, 2016 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	 Energy	 Corporate	 Total
EBITDA	**894**	**288**	**(34)**	**(51)**	**1,097**
Alberta PPA terminations	—	—	240	—	240
Acquisition costs - Columbia Pipeline Group	—	—	—	26	26
Keystone XL asset costs	—	10	—	—	10
TC Offshore loss on sale	4	—	—	—	4
Risk management activities	—	2	123	—	125
Comparable EBITDA	**898**	**300**	**329**	**(25)**	**1,502**
Depreciation and amortization	(287)	(70)	(88)	(9)	(454)
Comparable EBIT	**611**	**230**	**241**	**(34)**	**1,048**

three months ended March 31, 2015 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	 Energy	 Corporate	 Total
EBITDA	864	305	297	(24)	1,442
Risk management activities	—	—	89	—	89
Comparable EBITDA	864	305	386	(24)	1,531
Depreciation and amortization	(279)	(63)	(85)	(7)	(434)
Comparable EBIT	585	242	301	(31)	1,097

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

	2016	2015				2014		
(unaudited - millions of $, except per share amounts)	**First**	**Fourth**	**Third**	**Second**	**First**	**Fourth**	**Third**	**Second**
Revenues	**2,547**	2,851	2,944	2,631	2,874	2,616	2,451	2,234
Net income attributable to common shares	**252**	(2,458)	402	429	387	458	457	416
Comparable earnings	**494**	453	440	397	465	511	450	332
Share statistics								
Net income per common share - basic and diluted	**$0.36**	($3.47)	$0.57	$0.60	$0.55	$0.65	$0.64	$0.59
Comparable earnings per share	**$0.70**	$0.64	$0.62	$0.56	$0.66	$0.72	$0.63	$0.47
Dividends declared per common share	**$0.565**	$0.52	$0.52	$0.52	$0.52	$0.48	$0.48	$0.48

FACTORS AFFECTING QUARTERLY FINANCIAL INFORMATION BY BUSINESS SEGMENT

Quarter-over-quarter revenues and net income sometimes fluctuate, the causes of which vary across our business segments.

In Natural Gas Pipelines, quarter-over-quarter revenues and net income from the Canadian regulated pipelines generally remain relatively stable during any fiscal year. Our U.S. natural gas pipelines are generally seasonal in nature with higher earnings in the winter months as a result of increased customer demands. Over the long term, however, results from both our Canadian and U.S. natural gas pipelines fluctuate because of:

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

In Liquids Pipelines, revenues and net income are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income are also affected by:

- developments outside of the normal course of operations
- newly constructed assets being placed in service
- regulatory decisions.

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

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

FACTORS AFFECTING FINANCIAL INFORMATION BY QUARTER

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

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

In first quarter 2016, comparable earnings excluded:

- a $176 million after-tax impairment charge on the carrying value of our Alberta PPAs as a result of our decision to terminate the PPAs
- a charge of $26 million relating to costs associated with the acquisition of Columbia
- a charge of $6 million after tax related to Keystone XL costs for the maintenance and liquidation of project assets which are being expensed pending further advancement of the project
- an additional $3 million after-tax loss on the sale of TC Offshore which closed on March 31, 2016.

In fourth quarter 2015, comparable earnings excluded:

- a $2,891 million after-tax impairment charge on the carrying value of our investment in Keystone XL and related projects
- an $86 million after-tax loss provision related to the sale of TC Offshore expected to close in early 2016
- a net charge of $60 million after tax for our business restructuring and transformation initiative comprised of $28 million mainly related to 2015 severance costs and a provision of $32 million for 2016 planned severance costs and expected future losses under lease commitments. These charges form part of a restructuring initiative which commenced in 2015 to maximize the effectiveness and efficiency of our existing operations and reduce overall costs
- a $43 million after-tax charge relating to an impairment in value of turbine equipment held for future use in our Energy business
- a charge of $27 million after tax related to Bruce Power's retirement of debt in conjunction with the merger of the Bruce A and Bruce B partnerships
- a $199 million positive income adjustment related to the impact on our net income from non-controlling interests of TC PipeLines, LP's impairment of their equity investment in Great Lakes.

In third quarter 2015, comparable earnings excluded a charge of $6 million after-tax for severance costs as part of a restructuring initiative to maximize the effectiveness and efficiency of our existing operations.

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

In fourth quarter 2014, comparable earnings excluded an $8 million after-tax gain on the sale of our interest in Gas Pacifico/INNERGY.

In second quarter 2014, comparable earnings excluded a $99 million after-tax gain on the sale of Cancarb Limited and a $31 million after-tax loss related to the termination of the Niska Gas Storage contract.

Condensed consolidated statement of income

	three months ended March 31	
(unaudited - millions of Canadian $, except per share amounts)	**2016**	**2015**
Revenues		
Natural Gas Pipelines	**1,313**	1,305
Liquids Pipelines	**480**	443
Energy	**754**	1,126
	2,547	2,874
Income from Equity Investments	**135**	137
Operating and Other Expenses		
Plant operating costs and other	**715**	754
Commodity purchases resold	**514**	681
Property taxes	**141**	134
Depreciation and amortization	**454**	434
Asset impairment charges	**211**	—
	2,035	2,003
Loss on sale of assets	**(4)**	—
Financial Charges		
Interest expense	**420**	318
Interest income and other	**(201)**	14
	219	332
Income before Income Taxes	**424**	676
Income Tax Expense		
Current	**34**	68
Deferred	**36**	139
	70	207
Net Income	**354**	469
Net income attributable to non-controlling interests	**80**	59
Net Income Attributable to Controlling Interests	**274**	410
Preferred share dividends	**22**	23
Net Income Attributable to Common Shares	**252**	387
Net Income per Common Share		
Basic and diluted	**$0.36**	$0.55
Dividends Declared per Common Share	**$0.565**	$0.52
Weighted Average Number of Common Shares (millions)		
Basic	**702**	709
Diluted	**703**	710

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

	three months ended March 31	
(unaudited - millions of Canadian $)	**2016**	**2015**
Net Income	**354**	469
Other Comprehensive (Loss)/Income, Net of Income Taxes		
Foreign currency translation (losses)/gains on net investment in foreign operations	**(212)**	469
Change in fair value of net investment hedges	**(2)**	(266)
Change in fair value of cash flow hedges	**(39)**	15
Reclassification to net income of gains on cash flow hedges	**80**	44
Reclassification to net income of actuarial gains and prior service costs on pension and other post-retirement benefit plans	**4**	7
Other comprehensive income on equity investments	**3**	3
Other comprehensive (loss)/income (Note 8)	**(166)**	272
Comprehensive Income	**188**	741
Comprehensive (loss)/income attributable to non-controlling interests	**(26)**	207
Comprehensive Income Attributable to Controlling Interests	**214**	534
Preferred share dividends	**22**	23
Comprehensive Income Attributable to Common Shares	**192**	511

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of cash flows

	three months ended March 31	
(unaudited - millions of Canadian $)	**2016**	**2015**
Cash Generated from Operations		
Net income	**354**	469
Depreciation and amortization	**454**	434
Asset impairment charges	**211**	—
Deferred income taxes	**36**	139
Income from equity investments	**(135)**	(137)
Distributed earnings received from equity investments	**171**	135
Employee post-retirement benefits expense, net of funding	**11**	15
Loss on sale of assets	**4**	—
Equity allowance for funds used during construction	**(57)**	(33)
Unrealized losses on financial instruments	**71**	118
Other	**5**	13
Increase in operating working capital	**(80)**	(393)
Net cash provided by operations	**1,045**	760
Investing Activities		
Capital expenditures	**(836)**	(806)
Capital projects in development	**(67)**	(163)
Contributions to equity investments	**(170)**	(93)
Acquisitions, net of cash acquired	**(995)**	—
Proceeds from sale of assets, net of transaction costs	**6**	—
Distributions received in excess of equity earnings	**88**	46
Deferred amounts and other	**—**	179
Net cash used in investing activities	**(1,974)**	(837)
Financing Activities		
Notes payable issued, net	**1,176**	279
Long-term debt issued, net of issue costs	**1,992**	2,277
Long-term debt repaid	**(1,357)**	(1,016)
Dividends on common shares	**(365)**	(341)
Dividends on preferred shares	**(23)**	(22)
Distributions paid to non-controlling interests	**(62)**	(54)
Common shares issued, net of issue costs	**3**	10
Common shares repurchased	**(14)**	—
Preferred shares issued, net of issue costs	**—**	243
Partnership units of subsidiary issued, net of issue costs	**24**	4
Net cash provided by financing activities	**1,374**	1,380
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(57)**	29
Increase in Cash and Cash Equivalents	**388**	1,332
Cash and Cash Equivalents		
Beginning of period	**850**	489
Cash and Cash Equivalents		
End of period	**1,238**	1,821

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		March 31, 2016	December 31, 2015
ASSETS			
Current Assets			
Cash and cash equivalents		**1,238**	850
Accounts receivable		**1,381**	1,388
Inventories		**356**	323
Other		**1,162**	1,353
		4,137	3,914
Plant, Property and Equipment	net of accumulated depreciation of $22,301 and $22,299, respectively	**44,461**	44,817
Equity Investments		**6,275**	6,214
Regulatory Assets		**1,160**	1,184
Goodwill		**4,510**	4,812
Intangible and Other Assets		**3,012**	3,050
Restricted Investments		**403**	351
		63,958	64,342
LIABILITIES			
Current Liabilities			
Notes payable		**2,270**	1,218
Accounts payable and other		**2,875**	3,021
Accrued interest		**463**	520
Current portion of long-term debt		**1,529**	2,547
		7,137	7,306
Regulatory Liabilities		**1,447**	1,159
Other Long-Term Liabilities		**1,270**	1,260
Deferred Income Tax Liabilities		**5,031**	5,144
Long-Term Debt		**28,980**	28,909
Junior Subordinated Notes		**2,257**	2,409
		46,122	46,187
EQUITY			
Common shares, no par value		**12,099**	12,102
Issued and outstanding:	March 31, 2016 - 702 million shares		
	December 31, 2015 - 703 million shares		
Preferred shares		**2,499**	2,499
Additional paid-in capital		**—**	7
Retained earnings		**2,594**	2,769
Accumulated other comprehensive loss (Note 8)		**(999)**	(939)
Controlling Interests		**16,193**	16,438
Non-controlling interests		**1,643**	1,717
		17,836	18,155
		63,958	64,342

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

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of equity

	three months ended March 31	
(unaudited - millions of Canadian $)	**2016**	**2015**
Common Shares		
Balance at beginning of period	**12,102**	12,202
Shares issued on exercise of stock options	**3**	10
Shares repurchased	**(6)**	—
Balance at end of period	**12,099**	12,212
Preferred Shares		
Balance at beginning of period	**2,499**	2,255
Shares issued under public offering, net of issue costs	**—**	244
Balance at end of period	**2,499**	2,499
Additional Paid-In Capital		
Balance at beginning of period	**7**	370
Issuance of stock options, net of exercises	**5**	2
Dilution impact from TC PipeLines, LP units issued	**3**	1
Impact of common shares repurchased	**(8)**	—
Impact of asset drop down to TC PipeLines, LP	**(38)**	—
Reclassification of Additional Paid-In Capital deficit to Retained Earnings	**31**	—
Balance at end of period	**—**	373
Retained Earnings		
Balance at beginning of period	**2,769**	5,478
Net income attributable to controlling interests	**274**	410
Common share dividends	**(397)**	(369)
Preferred share dividends	**(21)**	(22)
Reclassification of Additional Paid-In Capital deficit to Retained Earnings	**(31)**	—
Balance at end of period	**2,594**	5,497
Accumulated Other Comprehensive Loss		
Balance at beginning of period	**(939)**	(1,235)
Other comprehensive (loss)/income	**(60)**	124
Balance at end of period	**(999)**	(1,111)
Equity Attributable to Controlling Interests	**16,193**	19,470
Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	**1,717**	1,583
Net income attributable to non-controlling interests		
TC PipeLines, LP	**71**	50
Portland	**9**	9
Other comprehensive (loss)/income attributable to non-controlling interests	**(106)**	148
Issuance of TC PipeLines, LP units		
Proceeds, net of issue costs	**24**	4
Decrease in TransCanada's ownership of TC PipeLines, LP	**(4)**	(1)
Distributions declared to non-controlling interests	**(68)**	(54)
Balance at end of period	**1,643**	1,739
Total Equity	**17,836**	21,209

See accompanying notes to the condensed consolidated financial statements.

Notes to condensed consolidated financial statements (unaudited)

1. Basis of presentation

These condensed consolidated financial statements of TransCanada Corporation (TransCanada or the Company) have been prepared by management in accordance with U.S. GAAP. The accounting policies applied are consistent with those outlined in TransCanada's annual audited consolidated financial statements for the year ended December 31, 2015, except as described in Note 2, Accounting changes. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in TransCanada's 2015 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 2015 audited consolidated financial statements included in TransCanada's 2015 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 segment due to the timing of regulatory decisions and seasonal fluctuations in short-term throughput volumes on U.S. pipelines. Earnings for interim periods may also not be indicative of results for the fiscal year in the Company's Energy segment due to the impact of seasonal weather conditions on customer demand and market pricing in certain of the Company's investments in electrical power generation plants and non-regulated gas storage facilities.

USE OF ESTIMATES AND JUDGEMENTS

In preparing these financial statements, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions. In the opinion of management, these condensed consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies included in the consolidated financial statements for the year ended December 31, 2015, except as described in Note 2, Changes in accounting policies.

2. Accounting Changes

CHANGES IN ACCOUNTING POLICIES FOR 2016

Extraordinary and unusual income statement items

In January 2015, the FASB issued new guidance on extraordinary and unusual income statement items. This update eliminates from GAAP the concept of extraordinary items. This new guidance was effective January 1, 2016, was applied prospectively and did not have a material impact on the Company's consolidated financial statements.

Consolidation

In February 2015, the FASB issued new guidance on consolidation. This update requires that entities re-evaluate whether they should consolidate certain legal entities and eliminates the presumption that a general partner should consolidate a limited partnership. This new guidance was effective January 1, 2016, was applied retrospectively and did not result in any change to the Company's consolidation conclusions. Disclosure requirements outlined in the new guidance are included in Note 13, Variable Interest Entities.

Imputation of interest

In April 2015, the FASB issued new guidance on simplifying the accounting for debt issuance costs. The amendments in this update require that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability consistent with debt discounts or premiums. This new guidance was effective January 1, 2016, was applied retrospectively and resulted in a reclassification of debt issuance costs previously recorded in Intangible and other assets to an offset of their respective debt liabilities on the Company's consolidated balance sheet.

Business combinations

In September 2015, the FASB issued guidance which intends to simplify the accounting measurement-period adjustments in business combinations. The amended guidance requires an acquirer to recognize adjustments to the provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. In the period the adjustment was determined, the guidance also requires the acquirer to record the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. This new guidance was effective January 1, 2016, was applied prospectively and did not have a material impact on the Company's consolidated financial statements.

FUTURE ACCOUNTING CHANGES

Revenue from contracts with customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. This guidance supersedes the current revenue recognition requirements and most industry-specific guidance. This new guidance requires that an entity recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In July 2015, the FASB deferred the effective date of this new standard to January 1, 2018, with early adoption not permitted before January 1, 2017. There are two methods in which the amendment can be applied: (1) retrospectively to each prior reporting period presented, or (2) retrospectively with the cumulative effect recognized at the date of initial application.

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.

Inventory

In July 2015, the FASB issued new guidance on simplifying the measurement of inventory. The amendments in this update specify that an entity should measure inventory within the scope of this update at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This new guidance is effective January 1, 2017 and will be applied prospectively. The Company does not expect the adoption of this new standard to have a material impact on its consolidated financial statements.

Financial instruments

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

Leases

In February 2016, the FASB issued new guidance on leases. The new guidance requires lessees to recognize most leases, including operating leases, on the balance sheet as lease assets and lease liabilities. In addition, lessees will be required to reassess assumptions associated with existing leases as well as to provide expanded qualitative and quantitative disclosures. The new standard does not make extensive changes to lessor accounting. The new guidance is effective January 1, 2019 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.

Derivatives and hedging

In March 2016, the FASB issued new guidance that clarifies the requirements for assessing whether contingent call or put options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. The new guidance requires only an assessment of the four-step decision sequence outlined in GAAP to determine whether the economic characteristics and risks of call or put options are clearly and closely related to the economic characteristics and risks. This new guidance is effective January 1, 2017 and 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.

Equity method investments

In March 2016, the FASB issued new guidance that simplifies the transition to equity method accounting. The new guidance eliminates the requirement to retroactively apply the equity method of accounting when an increase in ownership interest in an investment qualifies for equity method accounting. This new guidance is effective January 1, 2017 and will be applied prospectively. The Company does not expect the adoption of this new standard to have a material impact on its consolidated financial statements.

3. Segmented information

three months ended March 31	Natural Gas Pipelines		Liquids Pipelines		Energy		Corporate		Total	
(unaudited - millions of Canadian $)	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Revenues	**1,313**	1,305	**480**	443	**754**	1,126	**—**	—	**2,547**	2,874
Income from equity investments	**51**	54	**—**	—	**84**	83	**—**	—	**135**	137
Plant operating costs and other	**(372)**	(405)	**(125)**	(115)	**(167)**	(210)	**(51)**	(24)	**(715)**	(754)
Commodity purchases resold	**—**	—	**(44)**	—	**(470)**	(681)	**—**	—	**(514)**	(681)
Property taxes	**(94)**	(90)	**(23)**	(23)	**(24)**	(21)	**—**	—	**(141)**	(134)
Depreciation and amortization	**(287)**	(279)	**(70)**	(63)	**(88)**	(85)	**(9)**	(7)	**(454)**	(434)
Asset impairment charges	**—**	—	**—**	—	**(211)**	—	**—**	—	**(211)**	—
Loss on sale of assets	**(4)**	—	**—**	—	**—**	—	**—**	—	**(4)**	—
Segmented earnings/(losses)	**607**	585	**218**	242	**(122)**	212	**(60)**	(31)	**643**	1,008
Interest expense									**(420)**	(318)
Interest income and other									**201**	(14)
Income before income taxes									**424**	676
Income tax expense									**(70)**	(207)
Net income									**354**	469
Net income attributable to non-controlling interests									**(80)**	(59)
Net income attributable to controlling interests									**274**	410
Preferred share dividends									**(22)**	(23)
Net income attributable to common shares									**252**	387

TOTAL ASSETS

(unaudited - millions of Canadian $)	March 31, 2016	December 31, 2015
Natural Gas Pipelines	**30,374**	31,039
Liquids Pipelines	**15,622**	16,046
Energy	**15,934**	15,558
Corporate	**2,028**	1,699
	63,958	64,342

4. Asset impairment charges

Power Purchase Arrangements

On March 7, 2016, TransCanada issued notice to the Balancing Pool of the decision to terminate its Sheerness and Sundance A PPAs. In accordance with a provision in the PPAs, a buyer is permitted to terminate the arrangement if a change in law occurs that makes the arrangement unprofitable or more unprofitable. As a result of recent changes in law surrounding the Alberta Specified Gas Emitters Regulation, the Company expects increasing costs related to carbon emissions to continue throughout the remaining terms of the PPAs resulting in increasing unprofitabilty. As such, at March 31, 2016, the Company recognized a non-cash impairment charge of $211 million ($155 million after-tax) in its Energy segment, which represents the carrying value of the PPAs.

On March 7, 2016, TransCanada also issued notice to the Balancing Pool of the decision to terminate its Sundance B PPA. The Sundance B PPA is held in the ASTC Power Partnership in which the Company holds a 50 per cent ownership interest. As a result, the Company recognized a non-cash impairment charge of $29 million ($21 million after-tax) in its Energy segment, which represents the carrying value of the equity investment. This impairment charge is included in the income from equity investments on the condensed consolidated statement of income.

5. Income taxes

At March 31, 2016, the total unrecognized tax benefit of uncertain tax positions was approximately $18 million (December 31, 2015 - $17 million). TransCanada recognizes interest and penalties related to income tax uncertainties in income tax expense. Included in income tax expense for the three months ended March 31, 2016 is nil for interest expense and nil for penalties (March 31, 2015 - nil for interest expense and nil for penalties). At March 31, 2016, the Company had $4 million accrued for interest expense and nil accrued for penalties (December 31, 2015 - $4 million accrued for interest expense and nil for penalties).

The effective tax rates for the three-month periods ended March 31, 2016 and 2015 were 17 per cent and 31 per cent, respectively. The lower effective tax rate in 2016 was primarily the result of lower flow-through taxes in 2016 on Canadian regulated pipelines and changes in the proportion of income earned between Canadian and foreign jurisdictions.

6. Long-term debt

LONG-TERM DEBT ISSUED

The Company issued long-term debt in the three months ended March 31, 2016 as follows:

(unaudited - millions of Canadian $, unless noted otherwise)	Issue date	Type	Maturity date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	January 2016	Senior Unsecured Notes	January 2019	US $400	3.125%
	January 2016	Senior Unsecured Notes	January 2026	US $850	4.875%

LONG-TERM DEBT RETIRED

The Company retired long-term debt in the three months ended March 31, 2016 as follows:

(unaudited - millions of Canadian $, unless noted otherwise)	Retirement date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	January 2016	Senior Unsecured Notes	US $750	0.75%
NOVA GAS TRANSMISSION LTD.				
	February 2016	Debentures	$225	12.2%

In the three months ended March 31, 2016, TransCanada capitalized interest related to capital projects of $41 million (2015 - $70 million).

7. Equity and share capital

COMMON SHARES

In January 2016, the Company repurchased and cancelled 305,407 of its common shares at an average price of $44.90 for a total of $14 million (weighted average cost of $6 million). The difference of $8 million between the total price paid and the weighted average cost was recorded in Additional paid-in capital.

PREFERRED SHARES

On February 1, 2016, holders of 1.3 million Series 5 cumulative redeemable first preferred shares exercised their option to convert to Series 6 cumulative redeemable first preferred shares and receive quarterly floating rate cumulative dividends at an annual rate equal to the applicable 90-day Government of Canada treasury bill rate plus 1.54 per cent which will reset every quarter going forward. The fixed dividend rate on the remaining Series 5 preferred shares was reset for five years at 2.263 per cent per annum. Such rate will reset every five years.

PREFERRED SHARE CONVERSION

The following table summarizes the impact of the 2016 conversion of preferred shares discussed above:

(unaudited - millions of Canadian $, unless noted otherwise)	**Number of shares issued and outstanding** (thousands)	**Current yield**	**Annual dividend per share**[1]	**Redemption price per share**[2]	**Redemption and conversion option date**[2,3]	**Right to convert into**[3]
Cumulative first preferred shares						
Series 5	12,714	2.263%	$0.56575	$25.00	January 30, 2021	Series 6
Series 6	1,286	Floating[3,4]	Floating	$25.00	January 30, 2021	Series 5

1 Holders of the cumulative redeemable first preferred shares set out in this table are entitled to receive a fixed cumulative quarterly preferred dividend, as and when declared by the Board, with the exception of Series 6 preferred shares. The holders of Series 6 preferred shares are entitled to receive a quarterly floating rate cumulative preferred dividend as and when declared by the Board.

2 TransCanada may, at its option, redeem all or a portion of the outstanding shares for the redemption price per share, plus all accrued and unpaid dividends on the applicable redemption option date and on every fifth anniversary date thereafter. In addition, Series 6 preferred shares are redeemable by TransCanada at any time other than on a designated redemption option date for $25.50 per share plus all accrued and unpaid dividends on such redemption date.

3 The holder will have the right, subject to certain conditions, to convert their first preferred shares of a specified series into first preferred shares of another specified series on the conversion option date and every fifth anniversary thereafter.

4 Commencing March 31, 2016, the floating quarterly dividend rate for the Series 6 preferred shares is 2.002 per cent and will reset every quarter going forward.

8. 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 March 31, 2016 (unaudited - millions of Canadian $)	**Before tax amount**	**Income tax recovery/ (expense)**	**Net of tax amount**
Foreign currency translation losses on net investment in foreign operations	**(210)**	**(2)**	**(212)**
Change in fair value of net investment hedges	**(3)**	**1**	**(2)**
Change in fair value of cash flow hedges	**(54)**	**15**	**(39)**
Reclassification to net income of gains on cash flow hedges	**120**	**(40)**	**80**
Reclassification to net income of actuarial gains and prior service costs on pension and other post-retirement benefit plans	**5**	**(1)**	**4**
Other comprehensive income on equity investments	**4**	**(1)**	**3**
Other comprehensive loss	**(138)**	**(28)**	**(166)**

three months ended March 31, 2015 (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	460	9	469
Change in fair value of net investment hedges	(359)	93	(266)
Change in fair value of cash flow hedges	21	(6)	15
Reclassification to net income of gains and losses on cash flow hedges	73	(29)	44
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	10	(3)	7
Other comprehensive income on equity investments	4	(1)	3
Other comprehensive income	209	63	272

The changes in AOCI by component are as follows:

three months ended March 31, 2016 (unaudited - millions of Canadian $)	**Currency translation adjustments**	**Cash flow hedges**	**Pension and OPEB plan adjustments**	**Equity investments**	**Total**[1]
AOCI balance at January 1, 2016	**(383)**	**(97)**	**(198)**	**(261)**	**(939)**
Other comprehensive loss before reclassifications[2]	**(110)**	**(37)**	**—**	**—**	**(147)**
Amounts reclassified from accumulated other comprehensive loss	**—**	**80**	**4**	**3**	**87**
Net current period other comprehensive (loss)/ income[3]	**(110)**	**43**	**4**	**3**	**(60)**
AOCI balance at March 31, 2016	**(493)**	**(54)**	**(194)**	**(258)**	**(999)**

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

2 Other comprehensive loss before reclassifications on currency translation adjustments and cash flow hedges is net of non-controlling interest losses of $104 million and $2 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 $47 million ($28 million, net of tax) at March 31, 2016. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

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

(unaudited - millions of Canadian $)	Amounts reclassified from accumulated other comprehensive loss[1] three months ended March 31 2016	three months ended March 31 2015	Affected line item in the condensed consolidated statement of income
Cash flow hedges			
Commodities	**(82)**	(69)	Revenues (Energy)
Foreign exchange	**(34)**	—	Interest income and other
Interest	**(4)**	(4)	Interest expense
	(120)	(73)	Total before tax
	40	29	Income tax expense
	(80)	(44)	Net of tax
Pension and other post-retirement benefit plan adjustments			
Amortization of actuarial loss	**(5)**	(10)	[2]
	1	3	Income tax expense
	(4)	(7)	Net of tax
Equity investments			
Equity income	**(4)**	(4)	Income from equity investments
	1	1	Income tax expense
	(3)	(3)	Net of tax

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

2 These accumulated other comprehensive loss components are included in the computation of net benefit cost. Refer to Note 9 for additional detail.

9. Employee post-retirement benefits

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

	three months ended March 31			
	Pension benefit plans		Other post-retirement benefit plans	
(unaudited - millions of Canadian $)	**2016**	**2015**	**2016**	**2015**
Service cost	**26**	27	**1**	1
Interest cost	**30**	28	**2**	2
Expected return on plan assets	**(40)**	(38)	**—**	—
Amortization of actuarial loss	**4**	9	**1**	1
Amortization of regulatory asset	**4**	6	**—**	—
Net benefit cost recognized	**24**	32	**4**	4

10. Risk management and financial instruments

RISK MANAGEMENT OVERVIEW

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

COUNTERPARTY CREDIT RISK

TransCanada's maximum counterparty credit exposure with respect to financial instruments at March 31, 2016, without taking into account security held, consisted of accounts receivable, available for sale assets recorded at fair value, the fair value of derivative assets, notes, loans and advances receivable. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At March 31, 2016, there were no significant amounts past due or impaired, and there were no significant credit losses during the period.

The Company had a credit risk concentration due from a counterparty of $191 million (US$147 million) at March 31, 2016 (December 31, 2015 - $248 million (US$179 million)). This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's investment grade parent company.

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.

U.S. dollar-denominated debt designated as a net investment hedge

(unaudited - millions of Canadian $, unless noted otherwise)	March 31, 2016	December 31, 2015
Notional amount	**19,100 (US 14,700)**	23,100 (US 16,700)
Fair value	**20,100 (US 15,500)**	23,800 (US 17,200)

Derivatives designated as a net investment hedge

	March 31, 2016		December 31, 2015	
(unaudited - millions of Canadian $, unless noted otherwise)	Fair value[1]	Notional or principal amount	Fair value[1]	Notional or principal amount
Asset/(liability)				
U.S. dollar cross-currency interest rate swaps (maturing 2016 to 2019)[2]	**(573)**	**US 2,900**	(730)	US 3,150
U.S. dollar foreign exchange forward contracts (maturing 2016 to 2017)	**(58)**	**US 700**	50	US 1,800
	(631)	**US 3,600**	(680)	US 4,950

1 Fair values equal carrying values.

2 In the three months ended March 31, 2016, net realized gains of $2 million (2015 - gains of $3 million) related to the interest component of cross-currency swap settlements are included in interest expense.

FINANCIAL INSTRUMENTS

Non-derivative financial instruments

Fair value of non-derivative financial instruments

The fair value of the Company's Notes receivable is calculated by discounting future payments of interest and principal using forward interest rates. The fair value of Long-term debt and Junior subordinated notes is estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data service providers.

Available for sale assets are recorded at fair value which is calculated using quoted market prices where available. Certain non-derivative financial instruments included in cash and cash equivalents, accounts receivable, intangible and other assets, notes payable, accounts payable and other, accrued interest and other long-term liabilities have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity and would also be classified in Level II of the fair value hierarchy.

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

Balance sheet presentation of non-derivative financial instruments

The following table details the fair value of the non-derivative financial instruments, excluding those where carrying amounts approximate fair value, and would be classified in Level II of the fair value hierarchy:

	March 31, 2016		December 31, 2015	
(unaudited - millions of Canadian $)	Carrying amount	Fair value	Carrying amount	Fair value
Notes receivable[1]	**155**	**200**	214	265
Current and long-term debt[2,3]	**(30,509)**	**(33,515)**	(31,456)	(34,309)
Junior subordinated notes	**(2,257)**	**(1,745)**	(2,409)	(2,011)
	(32,611)	**(35,060)**	(33,651)	(36,055)

1. Notes receivable are included in other current assets and intangible and other assets on the condensed consolidated balance sheet.
2. Long-term debt is recorded at amortized cost except for US$900 million (December 31, 2015 - US$850 million) that is attributed to hedged risk and recorded at fair value.
3. Consolidated net income for the three months ended March 31, 2016 included unrealized losses of $12 million (March 31, 2015 - losses of $3 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$900 million of long-term debt at March 31, 2016 (December 31, 2015 - US$850 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Available for sale assets summary

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

	March 31, 2016		December 31, 2015	
(unaudited - millions of Canadian $)	LMCI restricted investments	Other restricted investments[2]	LMCI restricted investments	Other restricted investments[2]
Fair Values[1]				
Fixed income securities (maturing within 5 years)	**—**	**86**	—	90
Fixed income securities (maturing after 10 years)	**338**	**—**	261	—
	338	**86**	261	90

1. Available for sale assets are recorded at fair value and included in intangible and other assets on the condensed consolidated balance sheet.
2. Other restricted investments have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

	March 31, 2016		March 31, 2015	
(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	**5**	**1**	—	—

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

2 Unrealized gains and losses on other restricted investments are included in OCI.

Derivative instruments

Fair value of derivative instruments

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

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

Balance sheet presentation of derivative instruments

The balance sheet classification of the fair value of the derivative instruments as at March 31, 2016 is as follows:

at March 31, 2016 (unaudited - millions of Canadian $)	**Cash Flow Hedges**[1]	**Fair Value Hedges**[1]	**Net Investment Hedges**[1]	**Held for Trading**[1]	**Total Fair Value of Derivative Instruments**
Other current assets					
Commodities[2]	**37**	**—**	**—**	**481**	**518**
Foreign exchange	**—**	**—**	**7**	**25**	**32**
Interest rate	**—**	**5**	**—**	**1**	**6**
	37	**5**	**7**	**507**	**556**
Intangible and other assets					
Commodities[2]	**5**	**—**	**—**	**197**	**202**
Foreign exchange	**—**	**—**	**6**	**—**	**6**
Interest rate	**—**	**8**	**—**	**—**	**8**
	5	**8**	**6**	**197**	**216**
Total Derivative Assets	**42**	**13**	**13**	**704**	**772**
Accounts payable and other					
Commodities[2]	**(137)**	**—**	**—**	**(554)**	**(691)**
Foreign exchange	**(35)**	**—**	**(301)**	**(51)**	**(387)**
Interest rate	**(2)**	**—**	**—**	**(1)**	**(3)**
	(174)	**—**	**(301)**	**(606)**	**(1,081)**
Other long-term liabilities					
Commodities[2]	**—**	**—**	**—**	**(280)**	**(280)**
Foreign exchange	**—**	**—**	**(343)**	**—**	**(343)**
Interest rate	**(2)**	**—**	**—**	**—**	**(2)**
	(2)	**—**	**(343)**	**(280)**	**(625)**
Total Derivative Liabilities	**(176)**	**—**	**(644)**	**(886)**	**(1,706)**

1 Fair value equals carrying value.

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

The balance sheet classification of the fair value of the derivative instruments as at December 31, 2015 is as follows:

at December 31, 2015 (unaudited - millions of Canadian $)	**Cash Flow Hedges**[1]	**Fair Value Hedges**[1]	**Net Investment Hedges**[1]	**Held for Trading**[1]	**Total Fair Value of Derivative Instruments**
Other current assets					
Commodities[2]	46	—	—	326	372
Foreign exchange	—	—	65	2	67
Interest rate	—	1	—	2	3
	46	1	65	330	442
Intangible and other assets					
Commodities[2]	11	—	—	126	137
Foreign exchange	—	—	29	—	29
Interest rate	—	2	—	—	2
	11	2	29	126	168
Total Derivative Assets	57	3	94	456	610
Accounts payable and other					
Commodities[2]	(112)	—	—	(443)	(555)
Foreign exchange	—	—	(313)	(54)	(367)
Interest rate	(1)	(1)	—	(2)	(4)
	(113)	(1)	(313)	(499)	(926)
Other long-term liabilities					
Commodities[2]	(31)	—	—	(131)	(162)
Foreign exchange	—	—	(461)	—	(461)
Interest rate	(1)	(1)	—	—	(2)
	(32)	(1)	(461)	(131)	(625)
Total Derivative Liabilities	(145)	(2)	(774)	(630)	(1,551)

1 Fair value equals carrying value.

2 Includes purchases and sales of power and natural gas.

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

Notional and Maturity Summary

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

at March 31, 2016	Power	Natural Gas	Liquids	Foreign Exchange	Interest
Purchases[1]	**100,255**	**236**	**3**	**—**	**—**
Sales[1]	**72,789**	**157**	**4**	**—**	**—**
Millions of dollars	**—**	**—**	**—**	**US 5,853**	**US 1,500**
Maturity dates	**2016-2020**	**2016-2020**	**2016**	**2016**	**2016-2019**

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

at December 31, 2015	Power	Natural Gas	Foreign Exchange	Interest
Purchases[1]	70,331	133	—	—
Sales[1]	54,382	70	—	—
Millions of dollars	—	—	US 1,476	US 1,100
Maturity dates	2016–2020	2016–2020	2016	2016–2019

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

Unrealized and Realized (Losses)/Gains of Derivative Instruments

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

	three months ended March 31	
(unaudited - millions of Canadian $)	2016	2015
Derivative instruments held for trading[1]		
Amount of unrealized (losses)/gains in the period		
Commodities[2]	**(67)**	(26)
Foreign exchange	**27**	(29)
Amount of realized (losses)/gains in the period		
Commodities	**(95)**	1
Foreign exchange	**44**	(43)
Derivative instruments in hedging relationships		
Amount of realized (losses)/gains in the period		
Commodities	**(73)**	16
Foreign exchange	**(63)**	—
Interest rate	**2**	2

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

2 Following the March 17, 2016 announcement of the Company's intention to sell the U.S. Northeast merchant power assets, a loss of $49 million and a gain of $7 million (2015 - nil) were recorded in net income relating to discontinued cash flow hedges where it was probable that the anticipated underlying transaction would not occur as a result of a future sale.

Derivatives in cash flow hedging relationships

The components of OCI (Note 8) related to derivatives in cash flow hedging relationships are as follows:

	three months ended March 31	
(unaudited - millions of Canadian $, pre-tax)	2016	2015
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Commodities	**(16)**	21
Foreign exchange	**(35)**	—
Interest rate	**(1)**	—
	(52)	21
Reclassification of gains/(losses) on derivative instruments from AOCI to net income (effective portion)[1]		
Commodities[2]	**82**	69
Foreign exchange[3]	**34**	—
Interest rate[4]	**4**	4
	120	73
Losses on derivative instruments recognized in net income (ineffective portion)		
Commodities[2]	**(58)**	(63)
	(58)	(63)

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI.
2 Reported within revenues on the condensed consolidated statement of income.
3 Reported within interest income and other on the condensed consolidated statement of income.
4 Reported within interest expense on the condensed consolidated statement of income.

Offsetting of derivative instruments

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

at March 31, 2016 (unaudited - millions of Canadian $)	Gross derivative instruments presented on the balance sheet	Amounts available for offset[1]	Net amounts
Derivative - Asset			
Commodities	**720**	**(560)**	**160**
Foreign exchange	**38**	**(38)**	**—**
Interest rate	**14**	**(3)**	**11**
Total	**772**	**(601)**	**171**
Derivative - Liability			
Commodities	**(971)**	**560**	**(411)**
Foreign exchange	**(730)**	**38**	**(692)**
Interest rate	**(5)**	**3**	**(2)**
Total	**(1,706)**	**601**	**(1,105)**

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

The following table shows the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis as at December 31, 2015:

at December 31, 2015 (unaudited - millions of Canadian $)	Gross derivative instruments presented on the balance sheet	Amounts available for offset[1]	Net amounts
Derivative - Asset			
Commodities	509	(418)	91
Foreign exchange	96	(93)	3
Interest rate	5	(1)	4
Total	610	(512)	98
Derivative - Liability			
Commodities	(717)	418	(299)
Foreign exchange	(828)	93	(735)
Interest rate	(6)	1	(5)
Total	(1,551)	512	(1,039)

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

With respect to the derivative instruments presented above as at March 31, 2016, the Company provided cash collateral of $458 million (December 31, 2015 - $482 million) and letters of credit of $23 million (December 31, 2015 - $41 million) to its counterparties. The Company held nil (December 31, 2015 - nil) in cash collateral and $21 million (December 31, 2015 - $2 million) in letters of credit from counterparties on asset exposures at March 31, 2016.

Credit risk related contingent features of derivative instruments

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

Based on contracts in place and market prices at March 31, 2016, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $42 million (December 31, 2015 - $32 million), for which the Company had provided collateral in the normal course of business of nil (December 31, 2015 - nil). If the credit-risk-related contingent features in these agreements were triggered on March 31, 2016, the Company would have been required to provide additional collateral of $42 million (December 31, 2015 - $32 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 bank lines to meet these contingent obligations should they arise.

FAIR VALUE HIERARCHY

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

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

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

at March 31, 2016 (unaudited - millions of Canadian $, pre-tax)	**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	**45**	**645**	**30**	**720**
Foreign exchange	**—**	**38**	**—**	**38**
Interest rate	**—**	**14**	**—**	**14**
Derivative instrument liabilities:				
Commodities	**(121)**	**(829)**	**(21)**	**(971)**
Foreign exchange	**—**	**(730)**	**—**	**(730)**
Interest rate	**—**	**(5)**	**—**	**(5)**
	(76)	**(867)**	**9**	**(934)**

1 There were no transfers from Level I to Level II or from Level II to Level III for the three months ended March 31, 2016.

The fair value of the Company's assets and liabilities measured on a recurring basis, including both current and non-current portions for 2015, are categorized as follows:

at December 31, 2015 (unaudited - millions of Canadian $, pre-tax)	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	34	462	13	509
Foreign exchange	—	96	—	96
Interest rate	—	5	—	5
Derivative instrument liabilities:				
Commodities	(102)	(611)	(4)	(717)
Foreign exchange	—	(828)	—	(828)
Interest rate	—	(6)	—	(6)
	(68)	(882)	9	(941)

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2015.

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

	three months ended March 31	
(unaudited - millions of Canadian $, pre-tax)	**2016**	**2015**
Balance at beginning of period	**9**	4
Total gains/(losses) included in net income	**3**	(3)
Transfers out of Level III	**(3)**	—
Settlements	**1**	—
Sales	**(1)**	—
Total gains included in OCI	**—**	1
Balance at end of period[1]	**9**	2

1 For the three months ended months ended March 31, 2016, revenues include unrealized gains of $2 million attributed to derivatives in the Level III category that were still held at March 31, 2016 (2015 - losses of $3 million).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a less than $1 million increase or decrease in the fair value of outstanding derivative instruments included in Level III as at March 31, 2016.

11. Acquisitions and Dispositions

Natural Gas Pipelines

Portland Natural Gas Transmission System

On January 1, 2016, TransCanada completed the sale of a 49.9 per cent interest in Portland Natural Gas Transmission System (PNGTS) to TC PipeLines, LP for an aggregate purchase price of US$223 million. Proceeds were comprised of US$188 million in cash and the assumption of US$35 million in proportional PNGTS debt.

Columbia Pipeline Group, Inc.
On March 17, 2016, TransCanada entered into an agreement to acquire Columbia for a purchase price of US$10.2 billion in cash as well as the assumption of approximately US$2.8 billion of debt. The cash components of the acquisition will be financed through proceeds of $4.4 billion from the sale of the subscription receipts, committed bridge term loan credit facilities in the aggregate amount of US$6.9 billion and existing cash on hand. The sale of the subscription receipts, which are exchangeable into common shares at closing of the acquisition, was completed on April 1, 2016 through a public offering as described in Note 14, Subsequent events. The Company expects the acquisition to close in second half 2016 subject to various factors, including the timing of shareholder and regulatory approvals.

Iroquois Gas Transmission System LP
On March 31, 2016, TransCanada acquired a 4.87 per cent interest in Iroquois for an aggregate purchase price of US $53.8 million. As a result of this acquisition, TransCanada's interest in Iroquois has increased to 49.35 per cent.

TC Offshore LLC
On March 31, 2016, the Company completed the sale of TC Offshore LLC to a third party. This resulted in an additional loss on disposal of $4 million pre-tax which is included in loss on sale of assets in the condensed consolidated statement of income.

Energy

Ironwood
On February 1, 2016, TransCanada acquired the Ironwood natural gas fired, combined cycle power plant in Lebanon, Pennsylvania, with a capacity of 778 MW, for US$657 million in cash before post-acquisition adjustments. The Ironwood power plant delivers energy into the PJM power market. The Company measured the assets and liabilities acquired at fair value. The evaluation of assigned fair value is ongoing, however, preliminary findings indicate that the transaction will result in no goodwill. Upon acquisition, the Company began consolidating Ironwood. The revenues and earnings of Ironwood, since the date of acquisition, have not had a material impact on the consolidated results of the Company. In addition, the pro forma incremental impact on the Company's consolidated results for each of the periods presented is not material.

12. Commitments and guarantees

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

COMMITMENTS
TransCanada's commitments at December 31, 2015 included fixed payments, net of sublease receipts for Alberta PPAs. As a result of the March 7, 2016 notice to terminate our Sheerness, Sundance A and Sundance B PPAs, our future obligations from December 31, 2015 have decreased by: 2016 - $195 million, 2017 - $200 million, 2018 - $141 million, 2019 - $138 million and 2020 - $115 million.

GUARANTEES
TransCanada and its joint venture partner on Bruce Power, BPC Generation Infrastructure Trust (BPC), have each severally guaranteed certain contingent financial obligations of Bruce Power related to a lease agreement and contractor and supplier services. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, 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 related primarily to delivery of natural gas and the payment of liabilities. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

The carrying value of these guarantees has been included in other long-term liabilities. Information regarding the Company's guarantees is as follows:

		at March 31, 2016		at December 31, 2015	
(unaudited - millions of Canadian $)	Term	Potential exposure[1]	Carrying value	Potential exposure[1]	Carrying value
Bruce Power	ranging to 2018[2]	**88**	**1**	88	2
Other jointly owned entities	ranging to 2040	**81**	**25**	139	24
		169	**26**	227	26

1 TransCanada's share of the potential estimated current or contingent exposure.
2 Except for one guarantee with no termination date.

13. Variable interest entities

As a result of the implementation of the new FASB guidance on consolidation, a number of entities controlled by TransCanada are now considered to be variable interest entities (VIE). A VIE is a legal entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support or is structured such that equity investors lack the ability to make significant decisions relating to the entity's operations through voting rights or do not substantively participate in the gains and losses of the entity.

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

Consolidated VIEs

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

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

(unaudited - millions of Canadian $)	March 31, 2016	December 31, 2015
ASSETS		
Current Assets		
Cash and cash equivalents	**76**	54
Accounts receivable	**53**	55
Inventories	**23**	25
Other	**8**	6
	160	140
Plant, Property and Equipment	**3,639**	3,704
Equity Investments	**618**	664
Goodwill	**500**	541
	4,917	5,049
LIABILITIES		
Current Liabilities		
Accounts payable and other	**66**	74
Accrued interest	**22**	21
Current portion of long-term debt	**57**	45
	145	140
Regulatory Liabilities	**32**	33
Other Long-Term Liabilities	**5**	4
Deferred Income Tax Liabilities	**2**	—
Long-Term Debt	**3,045**	2,998
	3,229	3,175

Non-Consolidated VIEs

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

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

(unaudited - millions of Canadian $)	March 31, 2016	December 31, 2015
Balance sheet		
Equity investments	**5,520**	5,410
Off-balance sheet		
Potential exposure to guarantees (Note 12)	**169**	227
Maximum exposure to loss	**5,689**	5,637

14. Subsequent events

Subscription receipts

On April 1, 2016, the Company issued 96.6 million subscription receipts at a price of $45.75 each for total proceeds of approximately $4.4 billion. Each subscription receipt will entitle the holder to automatically receive one common share of the Company upon closing of the Columbia Pipeline Group acquisition. While the subscription receipts remain outstanding, holders will be entitled to receive cash payments per subscription receipt that are equal to dividends declared by TransCanada on each common share. The gross proceeds from the sale of the subscription receipts will be held in escrow until the acquisition close date and will be recorded as Restricted cash by the Company.

Preferred shares

On April 20, 2016, the Company completed a public offering of 20 million Series 13 cumulative redeemable first preferred shares at a price of $25.00 per share, resulting in gross proceeds of $500 million.