QuarterlyReport to Shareholders

TransCanada Reports Strong Second Quarter 2015 Financial Results
Remains Committed to 8-10 Per Cent Dividend Growth Through 2017

CALGARY, Alberta – **July 31, 2015** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada) today announced net income attributable to common shares for second quarter 2015 of $429 million or $0.60 per share compared to $416 million or $0.59 per share for the same period in 2014. Comparable earnings for second quarter 2015 were $397 million or $0.56 per share compared to $332 million or $0.47 per share for the same period last year. TransCanada's Board of Directors also declared a quarterly dividend of $0.52 per common share for the quarter ending September 30, 2015, equivalent to $2.08 per common share on an annualized basis.

"Our three core businesses produced another solid quarter of financial results demonstrating the resiliency of our high-quality asset base in challenging market conditions," said Russ Girling, TransCanada's president and chief executive officer. "Comparable earnings and funds generated from operations increased 20 and 16 per cent, respectively, compared to the same period last year highlighting the strong foundation that will allow us to continue to grow the dividend at an annual rate of eight to ten per cent through 2017 and fund our industry-leading $46 billion capital program."

Over the past several months, we advanced key components of our growth plans which included more than $13 billion in proposed natural gas pipeline projects to support the emerging liquefied natural gas (LNG) industry on the British Columbia (B.C.) Coast. Our Prince Rupert Gas Transmission (PRGT) project reached an important milestone with a positive Final Investment Decision (FID), subject to two conditions, from Pacific NorthWest LNG (PNW LNG). We also received the majority of the facilities permits for both our PRGT and Coastal GasLink projects which positions us to be ready to commence construction, pending a FID from the respective project sponsors. PRGT and Coastal GasLink also continued their engagement with Aboriginal groups along the pipeline routes and signed several project agreements with First Nation communities.

We also continue to advance the balance of our $46 billion portfolio of commercially secured projects as well as numerous other growth initiatives. These projects are expected to result in significant growth in earnings, cash flow and dividends through the end of the decade. With our high-quality asset base and financial strength, we remain well positioned to create long-term shareholder value throughout various market conditions.

Highlights

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

- Second quarter financial results
  - Net income attributable to common shares of $429 million or $0.60 per share
  - Comparable earnings of $397 million or $0.56 per share
  - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.4 billion
  - Funds generated from operations of $1.1 billion
- Declared a quarterly dividend of $0.52 per common share for the quarter ending September 30, 2015
- PRGT reached a significant milestone when PNW LNG announced a positive FID, subject to two conditions, for their proposed liquefaction and export facility on the West Coast of B.C.
- Received a majority of the pipeline and facilities permits for PRGT and Coastal GasLink
- Received regulatory approval for the $1.7 billion North Montney Mainline project
- Continued to advance our master limited partnership strategy with the drop down of the remaining 30 per cent interest in Gas Transmission Northwest LLC (GTN) for US$457 million
- Completed over $1.5 billion of financing with the issuance of junior subordinated and medium-term notes

Net income attributable to common shares increased by $13 million to $429 million or $0.60 per share for the three months ended June 30, 2015 compared to the same period last year. Second quarter 2015 included a $34 million income tax expense adjustment due to an increase in the Alberta corporate income tax rate and an

$8 million after-tax restructuring charge related to changes to our major projects group. Second quarter 2014 included a $99 million after-tax gain from the sale of Cancarb and a $31 million after-tax loss from the termination of a natural gas storage contract. 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 second quarter 2015 were $397 million or $0.56 per share compared to $332 million or $0.47 per share for the same period in 2014. Higher earnings from the Canadian Mainline, NGTL System, Keystone, Bruce Power and Eastern Power were partially offset by lower contributions from U.S. Power and Western Power.

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

Natural Gas Pipelines:

- *NGTL System Expansions:* The NGTL System has approximately $6.8 billion of new supply and demand facilities currently under development. In second quarter 2015, we continued to advance several of these capital expansion projects and plan to file additional facilities applications for this program through the remainder of 2015. We have received additional requests for firm receipt service that we anticipate will increase the overall capital spend on the NGTL System beyond the previously announced program and continue to work with our customers to best match their requirements for 2016, 2017 and 2018 in-service dates.

  On April 15, 2015, the National Energy Board (NEB) issued its report recommending the federal government approve the NGTL System's $1.7 billion North Montney Mainline project which will provide substantial new capacity on the NGTL System to meet the transportation requirements associated with rapidly increasing development of natural gas resources in the Montney supply basin in northeastern B.C. The project will connect Montney and other Western Canada Sedimentary Basin supply to both existing and new natural gas markets, notably emerging markets for LNG.

  The North Montney Mainline project will consist of two large diameter, 42-inch pipeline sections, Aitken Creek and Kahta, totaling approximately 301 kilometres (km) (187 miles) in length, and associated metering facilities, valve sites and compression facilities. The project will also include an interconnection with our proposed PRGT project to provide natural gas supply to the proposed PNW LNG liquefaction and export facility near Prince Rupert, B.C. NGTL currently expects to have the Aitken Creek Section in service in late 2016, and the Kahta Section in service in 2017.

  The Federal Government approved the recommendations of the report from the NEB, and on June 11, 2015, the NEB issued a Certificate of Public Convenience and Necessity to proceed with the project, subject to certain terms and conditions. Under one of these conditions, construction on the North Montney Mainline Project can only begin after a confirmation of FID has been made on the proposed PNW LNG project and we are proceeding with construction on PRGT.

- *Canadian Mainline:* On March 31, 2015, we submitted a compliance toll filing in response to direction from the NEB's RH-001-2014 Decision issued in November 2014. On June 12, 2015, the NEB approved the applied-for compliance tolls, as filed. These final tolls became effective on July 1, 2015 which allowed, among other things, the recording of incentive earnings as approved by the NEB.

  On June 2, 2015, the NEB approved construction of the King's North Connection project to expand gas transmission capacity in the greater Toronto area and provide shippers with the flexibility to source growing supplies of Marcellus gas from the U.S. Northeast. The project is expected to cost approximately $220 million and is anticipated to be in-service by third quarter 2016.

- *PRGT:* In second quarter 2015, we received six of the eleven pipeline and facilities permits from the B.C. Oil and Gas Commission (BC OGC) needed to build and operate PRGT. We anticipate decisions on the remaining BC OGC permits in third quarter 2015. PRGT is a 900 km (559 mile) natural gas pipeline that will deliver gas from the North Montney producing region near Fort St. John, B.C. at an interconnect on the NGTL System to the proposed PNW LNG facility near Prince Rupert, B.C.

We continued our engagement with Aboriginal groups along the pipeline route and during the quarter announced the signing of project agreements with Gitanyow First Nation, Kitselas First Nation, Lake Babine Nation, Doig River First Nation, Halfway River First Nation and Yekooche First Nation.

On June 11, 2015, PNW LNG announced a positive FID for the proposed liquefaction and export facility, subject to two conditions. The first condition is approval by the Legislative Assembly of B.C. of a Project Development Agreement between PNW LNG and the Province of B.C. This condition was satisfied in mid-July 2015. The second condition is a positive regulatory decision on PNW LNG's environmental assessment by the Government of Canada.

Subject to successful completion of the regulatory process for PRGT, we remain on target to begin construction following confirmation of a FID by PNW LNG. The in-service date for PRGT is estimated to be 2020 but will be aligned with PNW LNG's liquefaction facility timeline.

- *Coastal GasLink:* We have received eight of ten pipeline and facilities permits from the BC OGC and anticipate receiving the remaining two permits in third quarter 2015. We are continuing our engagement with Aboriginal groups along the pipeline route and on June 29, 2015 we announced the signing of project agreements with Wet'suwet'en First Nation, Skin Tyee Nation, Nee-Tahi-Buhn Band, Yekooche First Nation, Doig River First Nation and Halfway River First Nation, all of northern B.C.

  Coastal GasLink is a 670 km (416 mile) natural gas pipeline that will deliver gas from the Montney producing region at an expected interconnect on the NGTL System near Dawson Creek, B.C. to LNG Canada's proposed LNG facility near Kitimat, B.C. The project is subject to regulatory approvals and a positive FID.

- *GTN Drop Down*: On April 1, 2015, we closed the sale of our remaining 30 per cent interest in GTN to our master limited partnership, TC PipeLines, LP (the Partnership). The US$457 million sale, which included a US$11 million purchase price adjustment, was comprised of US$264 million in cash, the assumption of US$98 million in proportional GTN debt and the issuance of US$95 million of new Class B units to TransCanada. The Class B units entitle us to a cash distribution based on 30 per cent of GTN's annual cash distribution after certain thresholds are achieved, namely 100 per cent of distributions above US$20 million in the first five years and 25 per cent of distributions above US$20 million in subsequent years.

  The drop down of the remaining interest in GTN is part of a systematic series of transactions to sell the remainder of TransCanada's U.S. natural gas pipeline assets to the Partnership to help us fund our capital program.

  At June 30, 2015, we held a 28.2 per cent interest in the Partnership.

Liquids Pipelines:

- *Energy East Pipeline:* On April 2, 2015, we announced that the marine and associated tank terminal in Cacouna, Québec will not be built as a result of the recommended reclassification of beluga whales as an endangered species. We are currently evaluating other options and amendments to the project are expected to be submitted to the NEB in fourth quarter 2015. The NEB has continued to process the application in the interim.

  The alteration to the project scope and further refinement of the project schedule is expected to result in an in-service date of 2020. The original $12 billion cost estimate is expected to increase due to further scope refinement as we consult with stakeholders and escalation of construction costs as the project schedule is refined.

  Binding long-term contracts of approximately one million barrels per day (Bbl/d) for the 1.1 million Bbl/d pipeline have been secured and discussions with shippers continue.

- *Keystone Pipeline System:* In July 2015, the Keystone Pipeline System marked the safe delivery of the one billionth barrel of Canadian and U.S. crude oil and celebrated the five-year anniversary of the official start of oil deliveries for the 4,247 km (2,639 mile) cross-border pipeline from Hardisty, Alberta to markets in the American Midwest and in 2014 to the U.S. Gulf Coast.

  Construction continues on the 77 km (48 mile) Houston Lateral pipeline and tank terminal which will extend the Keystone Pipeline System to Houston, Texas refineries. The terminal is expected to have initial storage capacity for 700,000 barrels of crude oil. The pipeline and terminal are expected to be completed in fourth quarter 2015.

  On April 14, 2015, we, along with Magellan Midstream Partners L.P. (Magellan), announced a joint development agreement to connect our Houston Terminal to Magellan's East Houston Terminal. We will own 50 per cent of this US$50 million pipeline project which will enhance connections to the Houston market for our Keystone Pipeline System. Subject to definitive agreements and receipt of necessary permits and approvals, the pipeline is expected to be operational in late 2016.

- *Keystone XL:* In January 2015, the Department of State (DOS) re-initiated the national interest review and requested the eight federal agencies with a role in the review to complete their consideration of whether Keystone XL serves the national interest. All of the agency comments were submitted.

  On February 12, 2015, Nebraska county courts granted temporary injunctions that were negotiated between us and landowners' counsel which prevent Keystone from proceeding with condemnation cases until the underlying constitutional litigation is resolved. A renewed challenge to the constitutionality of the statute under which the Governor approved the re-route in the state is pending in a Nebraska District Court.

  On June 29, 2015, TransCanada sent a letter to the DOS with additional evidence demonstrating that Canada is taking strong steps toward managing carbon emissions.

  The South Dakota Public Utility Commission has scheduled a hearing in third quarter 2015 on our request to certify our existing permit authority in that state.

  The estimated capital cost for Keystone XL is expected to be approximately US$8.0 billion. As of June 30, 2015, we have invested US$2.4 billion in the project and have also capitalized interest in the amount of US$0.4 billion.

- *Heartland Pipeline and TC Terminals:* On May 7, 2015, the Alberta Energy Regulator issued a permit for construction of the Heartland Pipeline. The in-service date of the project will be aligned to meet market requirements for incremental capacity between the Heartland region near Edmonton, Alberta and Hardisty, Alberta.

  Crude oil prices continue to remain low, prompting many producers to cut capital spending and delay oil sands projects in western Canada. In its 2015 Crude Oil Forecast, Markets and Transportation report, the Canadian Association of Petroleum Producers estimated Western Canada Sedimentary Basin crude oil production will continue to grow but at a slower pace than previously anticipated. Our liquids pipelines projects are supported by long-term contracts. However, with the slowing in growth of crude oil production, our intra-Alberta projects may experience a similar slowing pace of growth to align with customer requirements.

Energy:

- *Alberta Greenhouse Gas (GHG) Emissions:* On June 25, 2015, the Alberta government announced a renewal and change to the Specified Gas Emitters Regulations (SGER) in Alberta. Since 2007 under the SGER, established industrial facilities with GHG emissions above a certain threshold are required to reduce their emissions by 12 per cent below an average intensity baseline and a carbon levy of $15 per tonne is placed on emissions above this target. The changed regulations include an increase in the emissions reductions target to 15 per cent in 2016 and 20 per cent in 2017, along with an increase in the carbon levy to $20 per tonne in 2016 and $30 per tonne in 2017. Our Sundance and Sheerness power purchase arrangements are subject to this regulation. Our significant inventory of carbon offset credits are expected to mitigate the majority of these increased costs. The remaining compliance costs are expected to be recovered through increased market pricing and contract flow through provisions.

- *Ravenswood:* In late May 2015, the 972 megawatt Unit 30 at the Ravenswood Generating Station returned to service after a September 2014 unplanned outage which resulted from a problem with the generator associated with the high pressure turbine.

Corporate:

- Our Board of Directors declared a quarterly dividend of $0.52 per share for the quarter ending September 30, 2015 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $2.08 per common share on an annualized basis.

- *Financing Activities:* In May 2015, a newly formed financing trust (the Trust) issued US$750 million of 60-year junior subordinated trust notes to third party investors with a fixed interest rate of 5.625 per cent for the first ten years converting to a floating rate thereafter. The notes are callable at par beginning ten years following their issuance. All of the proceeds of the issuance by the Trust were loaned to us in US$750 million junior subordinated notes at a rate of 5.875 per cent which includes a 0.25 per cent administration charge. On a subordinated basis, the obligations of the Trust are guaranteed by TransCanada.

  In July 2015, we issued $750 million of medium-term notes maturing on July 17, 2025 bearing interest at 3.30 per cent.

  The net proceeds of these offerings will be used for general corporate purposes and to reduce short-term indebtedness which was used to fund a portion of our capital program and for general corporate purposes.

- *Preferred Share Rate Reset and Conversion:* In June 2015, Series 3 shareholders converted 5.5 million of our 14 million outstanding Series 3 Cumulative Redeemable First Preferred Shares on a one-for-one basis into Series 4 floating-rate Cumulative Redeemable First Preferred Shares. The rate on the Series 3 Shares was reset and they will now pay an annual fixed dividend rate of 2.152 per cent on a quarterly basis for the five-year period which began on June 30, 2015. The Series 4 Shares will pay a floating quarterly dividend for the same five-year period with the rate set for the first quarterly floating rate period (June 30, 2015 to but excluding September 30, 2015) at 1.945 per cent per annum and will be reset every quarter going forward.

Teleconference and Webcast:

We will hold a teleconference and webcast on Friday, July 31, 2015 to discuss our second quarter 2015 financial results. Russ Girling, TransCanada president and chief executive officer, and Don Marchand, executive vice-president and chief financial officer, along with other members of the TransCanada executive leadership team, will discuss the financial results and Company developments at 9 a.m. (MT) / 11 a.m. (ET).

Analysts, members of the media and other interested parties are invited to participate by calling 866.225.6564 or 416.340.2218 (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 August 7, 2015. Please call 800.408.3053 or 905.694.9451 (Toronto area) and enter pass code 5657146.

The unaudited interim 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 60 years' experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and oil pipelines, power generation and gas storage facilities. TransCanada operates a network of natural gas pipelines that extends more than 68,000 kilometres (42,100 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 more than 368 billion cubic feet of storage capacity. A growing independent power producer, TransCanada owns or has interests in over 10,900 megawatts of power generation in Canada and the United States. TransCanada is developing one of North America's largest oil delivery systems. TransCanada's common shares trade on the Toronto and New York stock exchanges under the symbol TRP. For more information visit: www.transcanada.com or check us out on Twitter @TransCanada or http://blog.transcanada.com.

Forward Looking Information

This news 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 July 30, 2015 and 2014 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.

Non-GAAP Measures

This news release contains references to non-GAAP measures, including comparable earnings, comparable EBITDA, funds generated from operations and comparable earnings 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 July 30, 2015.

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Quarterly report to shareholders

Second quarter 2015

Financial highlights

(unaudited - millions of $, except per share amounts)	three months ended June 30		six months ended June 30	
	2015	**2014**	**2015**	**2014**
Income				
Revenue	**2,631**	2,234	**5,505**	5,118
Net income attributable to common shares	**429**	416	**816**	828
per common share - basic and diluted	**$0.60**	$0.59	**$1.15**	$1.17
Comparable EBITDA[1]	**1,367**	1,217	**2,898**	2,613
Comparable earnings[1]	**397**	332	**862**	754
per common share[1]	**$0.56**	$0.47	**$1.22**	$1.07
Operating cash flow				
Funds generated from operations[1]	**1,061**	917	**2,214**	2,019
(Increase)/decrease in operating working capital	**(92)**	202	**(485)**	79
Net cash provided by operations	**969**	1,119	**1,729**	2,098
Investing activities				
Capital expenditures	**966**	893	**1,772**	1,637
Capital projects under development	**172**	193	**335**	297
Equity investments	**105**	40	**198**	129
Proceeds from sale of assets, net of transaction costs	**—**	187	**—**	187
Dividends paid				
Per common share	**$0.52**	$0.48	**$1.04**	$0.96
Basic common shares outstanding (millions)				
Average for the period	**709**	708	**709**	708
End of period	**709**	708	**709**	708

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

Management's discussion and analysis

July 30, 2015

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TransCanada Corporation. It discusses our business, operations, financial position, risks and other factors for the three and six months ended June 30, 2015, and should be read with the accompanying unaudited condensed consolidated financial statements for the three and six months ended June 30, 2015 which have been prepared in accordance with U.S. GAAP.

This MD&A should also be read in conjunction with our December 31, 2014 audited consolidated financial statements and notes and the MD&A in our 2014 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 2014 Annual Report.

All information is as of July 30, 2015 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
- 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

- inflation rates, commodity prices and capacity prices
- timing of financings and hedging
- regulatory decisions and outcomes
- foreign exchange rates
- interest rates
- tax rates
- planned and unplanned outages and the use of our pipeline and energy assets
- integrity and reliability of our assets
- access to capital markets
- anticipated construction costs, schedules and completion dates
- acquisitions and divestitures.

Risks and uncertainties

- 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 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 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 2014 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
- comparable earnings
- comparable earnings per common share
- comparable EBITDA
- comparable EBIT
- comparable depreciation and amortization
- 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.

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 depreciation and amortization	depreciation and amortization
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
- write-downs of assets and investments.

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 - second quarter 2015

	three months ended June 30		six months ended June 30	
(unaudited - millions of $, except per share amounts)	**2015**	**2014**	**2015**	**2014**
Natural Gas Pipelines	**525**	496	**1,120**	1,082
Liquids Pipelines	**250**	195	**496**	387
Energy	**267**	216	**481**	473
Corporate	**(48)**	(27)	**(95)**	(70)
Total segmented earnings	**994**	880	**2,002**	1,872
Interest expense	**(331)**	(297)	**(649)**	(571)
Interest income and other expense	**81**	54	**67**	46
Income before income taxes	**744**	637	**1,420**	1,347
Income tax expense	**(250)**	(165)	**(457)**	(386)
Net income	**494**	472	**963**	961
Net income attributable to non-controlling interests	**(40)**	(31)	**(99)**	(85)
Net income attributable to controlling interests	**454**	441	**864**	876
Preferred share dividends	**(25)**	(25)	**(48)**	(48)
Net income attributable to common shares	**429**	416	**816**	828
Net income per common share - basic and diluted	**$0.60**	$0.59	**$1.15**	$1.17

Net income attributable to common shares increased by $13 million for the three months ended June 30, 2015 and decreased by $12 million for the six months ended June 30, 2015 compared to the same periods in 2014. The 2015 results included:

- a $34 million adjustment to income tax expense due to the enactment of a two per cent increase in the Alberta corporate income tax rate in June 2015
- 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.

The six-month 2014 results also included:

- a gain on sale of Cancarb Limited and its related power generation business of $99 million after tax
- a net loss resulting from the termination of a contract with Niska Gas Storage of $31 million after tax.

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

For the three and six months ended June 30, 2015, comparable earnings increased by $65 million and $108 million compared to the same periods in 2014 as discussed below in the reconciliation of net income to comparable earnings.

RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS

(unaudited - millions of $, except per share amounts)	three months ended June 30 2015	three months ended June 30 2014	six months ended June 30 2015	six months ended June 30 2014
Net income attributable to common shares	**429**	416	**816**	828
Specific items (net of tax):				
Alberta corporate income tax rate increase	**34**	—	**34**	—
Restructuring costs	**8**	—	**8**	—
Cancarb gain on sale	**—**	(99)	**—**	(99)
Niska contract termination	**—**	31	**—**	31
Risk management activities[1]	**(74)**	(16)	**4**	(6)
Comparable earnings	**397**	332	**862**	754
Net income per common share	**$0.60**	$0.59	**$1.15**	$1.17
Specific items (net of tax):				
Alberta corporate income tax rate increase	**0.05**	—	**0.05**	—
Restructuring costs	**0.01**	—	**0.01**	—
Cancarb gain on sale	**—**	(0.14)	**—**	(0.14)
Niska contract termination	**—**	0.04	**—**	0.04
Risk management activities[1]	**(0.10)**	(0.02)	**0.01**	—
Comparable earnings per share	**$0.56**	$0.47	**$1.22**	$1.07

1

Risk management activities (unaudited - millions of $)	three months ended June 30 2015	three months ended June 30 2014	six months ended June 30 2015	six months ended June 30 2014
Canadian Power	**29**	(2)	**7**	(2)
U.S. Power	**51**	(9)	**(17)**	(11)
Natural Gas Storage	**(1)**	6	**—**	(3)
Foreign exchange	**30**	25	**1**	23
Income tax attributable to risk management activities	**(35)**	(4)	**5**	(1)
Total gains/(losses) from risk management activities	**74**	16	**(4)**	6

Comparable earnings increased by $65 million for the three months ended June 30, 2015 compared to the same period in 2014. This was primarily the net effect of:

- higher earnings from Bruce Power from higher volumes as a result of fewer outage days at Bruce A partially offset by lower Bruce B volumes due to increased planned outage days
- higher uncontracted volumes on the Keystone Pipeline System
- higher earnings from Eastern Power due to incremental earnings from Ontario solar facilities acquired in the second half of 2014 and higher earnings at Cartier Wind
- higher earnings from Canadian Pipelines due to incentive earnings recorded for the Canadian Mainline and a higher average investment base on NGTL partially offset by lower Canadian Mainline ROE
- lower earnings from U.S. Power mainly due to the timing of earnings recognized on certain contracts in our power marketing business, reflecting the different pricing profiles between the power prices we charge our customers and the prices we pay for volumes purchased
- lower earnings from Western Power as a result of lower realized power prices and lower PPA volumes
- higher interest expense from new debt issuances and higher foreign exchange on interest related to U.S. dollar-denominated debt.

Comparable earnings increased by $108 million for the six months ended June 30, 2015 compared to the same period in 2014. This was primarily the net effect of:

- higher uncontracted volumes on the Keystone Pipeline System
- higher earnings from Eastern Power due to the sale of unused natural gas transportation, higher contractual earnings at Bécancour and incremental earnings from Ontario solar facilities acquired in the second half of 2014
- higher earnings from Bruce Power from increased volumes as a result of fewer outage days at Bruce A, partially offset by lower Bruce B volumes due to increased planned outage days

- higher earnings from U.S. and International Pipelines due to increased earnings from the Tamazunchale Extension which was placed in service in 2014, higher ANR Southeast transportation revenue and ANR's first quarter 2015 settlement with a producer for damages to ANR's pipeline. These were partially offset by increased spending on pipeline integrity work
- higher earnings from U.S. Power mainly due to increased margins on and higher sales volumes to wholesale, commercial and industrial customers partially offset by lower earnings from U.S. generating assets primarily due to the impact of lower realized power prices
- lower earnings from Western Power as a result of lower realized power prices and lower PPA volumes
- higher interest expense from debt issuances and higher foreign exchange on interest related to U.S. dollar-denominated debt.

The stronger U.S. dollar this quarter compared to the same period in 2014 positively impacted the translated results in our U.S. businesses, however, this impact was mostly offset by a corresponding increase in interest expense on U.S. dollar-denominated debt as well as realized losses on foreign exchange hedges used to manage our net exposure through our hedging program.

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 is comprised of $12 billion of small to medium-sized, shorter-term projects and $34 billion of commercially secured large-scale, medium and longer-term projects. Amounts presented exclude the impact of foreign exchange and capitalized interest.

Estimated project costs are generally based on the last announced project estimates and are subject to cost adjustments due to market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits.

at June 30, 2015 (unaudited - billions of $)	**Segment**	**Expected in-service date**	**Estimated project cost**	**Amount spent**
Small to medium sized, shorter-term				
Houston Lateral and Terminal	Liquids Pipelines	2015	US 0.6	US 0.5
Topolobampo	Natural Gas Pipelines	2016	US 1.0	US 0.8
Mazatlan	Natural Gas Pipelines	2016	US 0.4	US 0.3
Grand Rapids[1]	Liquids Pipelines	2016-2017	1.5	0.3
Heartland and TC Terminals	Liquids Pipelines	[2]	0.9	0.1
Northern Courier	Liquids Pipelines	2017	1.0	0.4
Canadian Mainline	Natural Gas Pipelines	2015-2016	0.4	—
NGTL System - North Montney	Natural Gas Pipelines	2016-2017	1.7	0.2
- 2016/17 Facilities	Natural Gas Pipelines	2016-2018	2.7	0.1
- Other	Natural Gas Pipelines	2015-2017	0.5	0.1
Napanee	Energy	2017 or 2018	1.0	0.2
			11.7	3.0
Large-scale, medium and longer-term				
Upland	Liquids Pipelines	2020	US 0.6	US —
Keystone projects				
Keystone XL[3]	Liquids Pipelines	[4]	US 8.0	US 2.4
Keystone Hardisty Terminal	Liquids Pipelines	[4]	0.3	0.2
Energy East projects				
Energy East[5]	Liquids Pipelines	2020	12.0	0.7
Eastern Mainline	Natural Gas Pipelines	2019	1.5	—
BC west coast LNG-related projects				
Coastal GasLink	Natural Gas Pipelines	2019+	4.8	0.3
Prince Rupert Gas Transmission	Natural Gas Pipelines	2020	5.0	0.4
NGTL System - Merrick	Natural Gas Pipelines	2020	1.9	—
			34.1	4.0
			45.8	7.0

1 Represents our 50 per cent share.
2 In-service date to be aligned with industry requirements.
3 Estimated project cost dependent on the timing of the Presidential permit.
4 Approximately two years from the date the Keystone XL permit is received.
5 Excludes transfer of Canadian Mainline natural gas assets.

Outlook

The earnings outlook for 2015 is expected to be consistent with what was previously included in the 2014 Annual Report. See the MD&A in our 2014 Annual Report for further information about our outlook.

Natural Gas Pipelines

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	2015	2014	2015	2014
Comparable EBITDA	**807**	759	**1,681**	1,607
Comparable depreciation and amortization[1]	**(282)**	(263)	**(561)**	(525)
Comparable EBIT	**525**	496	**1,120**	1,082
Specific items[2]	**—**	—	**—**	—
Segmented earnings	**525**	496	**1,120**	1,082

1 Comparable depreciation and amortization is equivalent to the GAAP measure, depreciation and amortization.
2 There were no specific items in any of these periods.

Natural Gas Pipelines segmented earnings increased by $29 million and $38 million for the three and six months ended June 30, 2015 compared to the same periods in 2014 and are equivalent to comparable EBIT which, along with comparable EBITDA, are discussed below.

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	2015	2014	2015	2014
Canadian Pipelines				
Canadian Mainline	**321**	312	**587**	627
NGTL System	**227**	205	**449**	424
Foothills	**28**	27	**55**	54
Other Canadian pipelines[1]	**7**	5	**14**	10
Canadian Pipelines - comparable EBITDA	**583**	549	**1,105**	1,115
Comparable depreciation and amortization	**(211)**	(204)	**(420)**	(407)
Canadian Pipelines - comparable EBIT	**372**	345	**685**	708
U.S. and International Pipelines (US$)				
ANR	**35**	33	**123**	111
TC PipeLines, LP[1,2]	**25**	21	**51**	47
Great Lakes[3]	**7**	9	**27**	28
Other U.S. pipelines (Bison[4], Iroquois[1], GTN[5], Portland[6])	**12**	29	**53**	74
Mexico (Guadalajara, Tamazunchale)	**47**	49	**94**	74
International and other[1,7]	**2**	(1)	**4**	(2)
Non-controlling interests[8]	**66**	54	**140**	127
U.S. and International Pipelines - comparable EBITDA	**194**	194	**492**	459
Comparable depreciation and amortization	**(57)**	(54)	**(114)**	(108)
U.S. and International Pipelines - comparable EBIT	**137**	140	**378**	351
Foreign exchange impact	**30**	13	**89**	34
U.S. and International Pipelines - comparable EBIT (Cdn$)	**167**	153	**467**	385
Business Development comparable EBITDA and EBIT	**(14)**	(2)	**(32)**	(11)
Natural Gas Pipelines - comparable EBIT	**525**	496	**1,120**	1,082

1 Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect our share of equity income from these investments. In November 2014, we sold our interest in Gas Pacifico/INNERGY.

2 Beginning in August 2014, TC PipeLines, LP began its at-the-market equity issuance program which, when utilized, decreases ownership interest in TC PipeLines, LP. On October 1, 2014, we sold our remaining 30 per cent direct interest in Bison to TC PipeLines, LP. On April 1, 2015, we sold our remaining 30 per cent direct interest in GTN to TC PipeLines, LP. The following shows our ownership interest in TC PipeLines, LP and our effective ownership interest of GTN, Bison and Great Lakes through our ownership interest in TC PipeLines, LP for the periods presented.

	Ownership percentage as of			
	June 30, 2015	April 1, 2015	October 1, 2014	January 1, 2014
TC PipeLines, LP	28.2	28.3	28.3	28.9
Effective ownership through TC PipeLines, LP:				
Bison	28.2	28.3	28.3	20.2
GTN	28.2	28.3	19.8	20.2
Great Lakes	13.1	13.1	13.1	13.4

3 Represents our 53.6 per cent direct ownership interest. The remaining 46.4 per cent is held by TC PipeLines, LP.
4 Effective October 1, 2014, we have no direct ownership in Bison. Prior to that our direct ownership interest was 30 per cent effective July 1, 2013.
5 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.
6 Represents our 61.7 per cent ownership interest.
7 Includes our share of the equity income from Gas Pacifico/INNERGY and TransGas as well as general and administration costs relating to our U.S. and International Pipelines. In November 2014, we sold our interest in Gas Pacifico/INNERGY.
8 Comparable EBITDA for the portions of TC PipeLines, LP and Portland we do not own.

CANADIAN PIPELINES

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

NET INCOME - WHOLLY OWNED CANADIAN PIPELINES

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2015**	2014	**2015**	2014
Canadian Mainline	**67**	58	**114**	124
NGTL System	**66**	58	**130**	121
Foothills	**4**	4	**8**	8

Net income for the Canadian Mainline increased by $9 million for the three months ended June 30, 2015 compared to the same period in 2014 because of incentive earnings recorded in second quarter 2015 following approval by the NEB in June 2015 of the 2015 - 2020 Mainline Transportation Tolls Compliance Filing. This was partially offset by a lower ROE of 10.10 per cent on deemed common equity of 40 per cent in 2015 compared to 11.50 per cent in 2014 and a lower average investment base in 2015. Net income decreased by $10 million for the six months ended June 30, 2015 compared to the same period in 2014 due to a lower ROE and a lower average investment base in 2015, partially offset by the incentive earnings recorded in second quarter 2015.

Net income for the NGTL System increased by $8 million and $9 million for three and six months ended June 30, 2015 compared to the same periods in 2014 mainly due to a higher average investment base and no OM&A incentive losses realized in 2015.

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 unchanged for the three months ended June 30, 2015 and increased by US$33 million for six months ended June 30, 2015 compared to the same periods in 2014. The year to date increase was the net effect of:

- higher earnings from the Tamazunchale Extension which was placed in service in 2014
- higher ANR Southeast transportation revenue and ANR's first quarter 2015 settlement with a producer for damages to ANR's pipeline, partially offset by increased spending on pipeline integrity work.

A stronger U.S. dollar had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. and International operations.

COMPARABLE DEPRECIATION AND AMORTIZATION

Comparable depreciation and amortization increased by $19 million and $36 million for three and six months ended June 30, 2015 compared to the same periods in 2014 mainly because of depreciation for the Tamazunchale Extension, a higher investment base on the NGTL System and the effect of a stronger U.S. dollar.

BUSINESS DEVELOPMENT

Business development expenses were higher by $12 million and $21 million for the three and six months ended June 30, 2015 compared to the same periods in 2014 mainly due to increased business development activity.

OPERATING STATISTICS - WHOLLY OWNED PIPELINES

six months ended June 30	**Canadian Mainline[1]**		**NGTL System[2]**		**ANR[3]**	
(unaudited)	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**
Average investment base (millions of $)	**4,925**	5,667	**6,505**	6,179	**n/a**	n/a
Delivery volumes (Bcf)						
Total	**864**	842	**1,948**	1,996	**862**	863
Average per day	**4.8**	4.7	**10.8**	11.0	**4.8**	4.8

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 six months ended June 30, 2015 were 564 Bcf (2014 – 599 Bcf). Average per day was 3.1 Bcf (2014 – 3.3 Bcf).

2 Field receipt volumes for the NGTL System for the six months ended June 30, 2015 were 2,006 Bcf (2014 – 1,879 Bcf). Average per day was 11.1 Bcf (2014 – 10.4 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).

(unaudited - millions of $)	three months ended June 30		six months ended June 30	
	2015	**2014**	**2015**	**2014**
Comparable EBITDA	**316**	249	**625**	490
Comparable depreciation and amortization[1]	**(66)**	(54)	**(129)**	(103)
Comparable EBIT	**250**	195	**496**	387
Specific items[2]	**—**	—	**—**	—
Segmented earnings	**250**	195	**496**	387

1 Comparable depreciation and amortization is equivalent to the GAAP measure, depreciation and amortization.
2 There were no specific items in any of these periods.

Liquids Pipelines segmented earnings increased by $55 million and $109 million for the three and six months ended June 30, 2015 compared to the same periods in 2014 and are equivalent to comparable EBIT which, along with comparable EBITDA, are discussed below.

(unaudited - millions of $)	three months ended June 30		six months ended June 30	
	2015	**2014**	**2015**	**2014**
Keystone Pipeline System	**320**	256	**634**	504
Liquids Pipelines Business Development	**(4)**	(7)	**(9)**	(14)
Liquids Pipelines - comparable EBITDA	**316**	249	**625**	490
Comparable depreciation and amortization	**(66)**	(54)	**(129)**	(103)
Liquids Pipelines - comparable EBIT	**250**	195	**496**	387
Comparable EBIT denominated as follows:				
Canadian dollars	**56**	50	**117**	99
U.S. dollars	**158**	133	**307**	262
Foreign exchange impact	**36**	12	**72**	26
	250	195	**496**	387

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 increased by $64 million and $130 million for the three and six months ended June 30, 2015 compared to the same periods in 2014. These increases were primarily due to:

- higher uncontracted volumes
- incremental earnings from the Gulf Coast extension which was placed in service in late January 2014
- a stronger U.S. dollar and its positive effect on the foreign exchange impact

COMPARABLE DEPRECIATION AND AMORTIZATION

Comparable depreciation and amortization increased by $12 million and $26 million for the three and six months ended June 30, 2015 compared to the same periods in 2014 due to the Gulf Coast extension being placed in service and the effect of a stronger U.S. dollar.

Energy

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

(unaudited - millions of $)	three months ended June 30		six months ended June 30	
	2015	**2014**	**2015**	**2014**
Comparable EBITDA	**272**	231	**660**	576
Comparable depreciation and amortization[1]	**(84)**	(77)	**(169)**	(154)
Comparable EBIT	**188**	154	**491**	422
Specific items (pre-tax):				
Cancarb gain on sale	**—**	108	**—**	108
Niska contract termination	**—**	(41)	**—**	(41)
Risk management activities	**79**	(5)	**(10)**	(16)
Segmented earnings	**267**	216	**481**	473

1 Comparable depreciation and amortization is equivalent to the GAAP measure, depreciation and amortization.

Energy segmented earnings increased by $51 million and $8 million for the three and six months ended June 30, 2015 compared to the same periods in 2014 and included the following unrealized gains and losses from risk management activities:

Risk management activities (unaudited - millions of $, pre-tax)	three months ended June 30		six months ended June 30	
	2015	**2014**	**2015**	**2014**
Canadian Power	**29**	(2)	**7**	(2)
U.S. Power	**51**	(9)	**(17)**	(11)
Natural Gas Storage	**(1)**	6	**—**	(3)
Total gains/(losses) from risk management activities	**79**	(5)	**(10)**	(16)

The period over period 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 particular 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.

A significant portion of the unrealized risk management activity gains in U.S. Power for second quarter 2015 are due to the reversal of unrealized risk management activity losses from our power marketing business that were recognized and discussed in first quarter 2015. Please see the U.S. Power section of this MD&A for further discussion on these timing differences.

Canadian Power gains from risk management activities in second quarter 2015 are a result of higher Alberta forward power prices at June 30, 2015.

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2015**	**2014**	**2015**	**2014**
Canadian Power				
Western Power	**34**	46	**49**	118
Eastern Power	**91**	70	**222**	163
Bruce Power	**66**	24	**145**	88
Canadian Power - comparable EBITDA[1]	**191**	140	**416**	369
Comparable depreciation and amortization	**(46)**	(45)	**(94)**	(89)
Canadian Power - comparable EBIT[1]	**145**	95	**322**	280
U.S. Power (US$)				
U.S. Power - comparable EBITDA	**64**	88	**197**	174
Comparable depreciation and amortization	**(28)**	(27)	**(55)**	(54)
U.S. Power - comparable EBIT	**36**	61	**142**	120
Foreign exchange impact	**8**	6	**32**	11
U.S. Power - comparable EBIT (Cdn$)	**44**	67	**174**	131
Natural Gas Storage and other - comparable EBITDA	**6**	2	**9**	29
Comparable depreciation and amortization	**(3)**	(3)	**(6)**	(6)
Natural Gas Storage and other - comparable EBIT	**3**	(1)	**3**	23
Business Development comparable EBITDA and EBIT	**(4)**	(7)	**(8)**	(12)
Energy - comparable EBIT[1]	**188**	154	**491**	422

1 Includes our share of equity income from our investments in ASTC Power Partnership, Portlands Energy and Bruce Power.

Comparable EBITDA for Energy increased by $41 million for the three months ended June 30, 2015 compared to the same period in 2014 due to the net effect of:

- higher earnings from Bruce Power from higher volumes as a result of fewer outage days at Bruce A, partially offset by lower Bruce B volumes due to increased planned outage days
- higher earnings from Eastern Power due to incremental earnings from Ontario solar facilities acquired in the second half of 2014 and higher earnings at Cartier Wind
- lower earnings from U.S. Power mainly due to the timing of earnings recognized on certain contracts in our power marketing business, reflecting the different pricing profiles between the power prices we charge our customers and the prices we pay for volumes purchased
- lower earnings from Western Power as a result of lower realized power prices and lower PPA volumes.

Comparable EBITDA for Energy increased by $84 million for the six months ended June 30, 2015 compared to the same period in 2014 due to the net effect of:

- higher earnings from Eastern Power due to the sale of unused natural gas transportation, higher contractual earnings at Bécancour and incremental earnings from Ontario solar facilities acquired in 2014
- higher earnings from Bruce Power from increased volumes as a result of fewer outage days at Bruce A partially offset by lower Bruce B volumes due to increased planned outage days
- higher earnings from U.S. Power mainly due to increased margins and higher sales volumes to wholesale, commercial and industrial customers primarily offset by lower earnings on U.S. generating assets primarily due to the impact of lower realized power prices
- lower earnings from Western Power as a result of lower realized power prices and lower PPA volumes
- lower earnings from Natural Gas Storage due to lower realized natural gas price spreads
- a stronger U.S. dollar and its positive effect on the foreign exchange impact.

CANADIAN POWER

Western and Eastern Power

(unaudited - millions of $)	three months ended June 30 2015	2014	six months ended June 30 2015	2014
Revenue[1]				
Western Power	**178**	160	**286**	341
Eastern Power	**114**	88	**239**	230
Other[2]	**3**	6	**48**	57
	295	254	**573**	628
Income from equity investments[3]	**10**	8	**15**	28
Commodity purchases resold	**(93)**	(90)	**(183)**	(191)
Plant operating costs and other	**(58)**	(58)	**(127)**	(186)
Exclude risk management activities[1]	**(29)**	2	**(7)**	2
Comparable EBITDA	**125**	116	**271**	281
Comparable depreciation and amortization	**(46)**	(45)	**(94)**	(89)
Comparable EBIT	**79**	71	**177**	192
Breakdown of comparable EBITDA				
Western Power	**34**	46	**49**	118
Eastern Power	**91**	70	**222**	163
Comparable EBITDA	**125**	116	**271**	281

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, sale of excess natural gas purchased for generation and Cancarb sales of thermal carbon black up to April 15, 2014 when it was sold.

3 Includes our share of equity income from our investments in ASTC Power Partnership, which holds the Sundance B PPA, and Portlands Energy. Equity income does not include any earnings related to our risk management activities.

Sales volumes and plant availability

Includes our share of volumes from our equity investments.

(unaudited)	three months ended June 30 2015	2014	six months ended June 30 2015	2014
Sales volumes (GWh)				
Supply				
Generation				
Western Power	**650**	611	**1,287**	1,220
Eastern Power	**739**	596	**2,062**	1,873
Purchased				
Sundance A & B and Sheerness PPAs[1]	**2,472**	2,598	**4,860**	5,398
Other purchases	**20**	2	**28**	7
	3,881	3,807	**8,237**	8,498
Sales				
Contracted				
Western Power	**1,794**	2,434	**3,439**	4,895
Eastern Power	**739**	596	**2,062**	1,873
Spot				
Western Power	**1,348**	777	**2,736**	1,730
	3,881	3,807	**8,237**	8,498
Plant availability[2]				
Western Power[3]	**97%**	94%	**97%**	95%
Eastern Power[4,5]	**98%**	73%	**98%**	86%

1 Includes our 50 per cent ownership interest of Sundance B volumes through the ASTC Power Partnership.
2 The percentage of time the plant was available to generate power, regardless of whether it was running.
3 Does not include facilities that provide power to us under PPAs.
4 Does not include Bécancour because power generation has been suspended since 2008.
5 Higher plant availability in Eastern Power was the result of higher availability at Halton Hills because of a maintenance outage in second quarter 2014.

Western Power

Comparable EBITDA for Western Power decreased by $12 million and $69 million for the three and six months ended June 30, 2015 compared to the same periods in 2014. The decreases were primarily due to lower realized power prices, lower PPA volumes and lower earnings following the sale of Cancarb in April 2014.

Average spot market power prices in Alberta increased by 36 per cent from $42/MWh to $57/MWh for the three months ended June 30, 2015 and decreased 17 per cent from $52/MWh to $43/MWh for the six months ended June 30, 2015, compared to the same periods in 2014. Unexpected plant outages, lower wind output and higher weather driven power demand resulted in higher average spot power prices in second quarter 2015. 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.

Although Alberta average spot power prices were higher in second quarter 2015, the market remains well supplied. Lower spot power prices are expected to continue in the near term and 2015 Western Power earnings are anticipated to be lower compared to 2014. Longer-term, we expect prices to return to higher levels as excess supply is absorbed by growth in power demand and aging generation infrastructure is retired.

Fifty-seven per cent of Western Power sales volumes were sold under contract in second quarter 2015 compared to 76 per cent in second quarter 2014.

Eastern Power

Comparable EBITDA for Eastern Power increased by $21 million for the three months ended June 30, 2015 compared to the same period in 2014 mainly due to incremental earnings from solar facilities acquired in 2014 and higher earnings at Cartier Wind.

Comparable EBITDA for Eastern Power increased by $59 million for the six months ended June 30, 2015 compared to the same period in 2014 mainly due to the sale of unused natural gas transportation, higher contractual earnings at Bécancour and incremental earnings from solar facilities acquired in the second half of 2014.

BRUCE POWER

Our proportionate share

	three months ended June 30		six months ended June 30	
(unaudited - millions of $, unless noted otherwise)	**2015**	2014	**2015**	2014
Income/(loss) from equity investments[1]				
Bruce A	**91**	(2)	**147**	47
Bruce B	**(25)**	26	**(2)**	41
	66	24	**145**	88
Comprised of:				
Revenues	**316**	265	**647**	565
Operating expenses	**(167)**	(164)	**(339)**	(321)
Depreciation and other	**(83)**	(77)	**(163)**	(156)
	66	24	**145**	88
Bruce Power - Other information				
Plant availability[2]				
Bruce A	**98%**	64%	**94%**	72%
Bruce B	**54%**	93%	**75%**	89%
Combined Bruce Power	**75%**	79%	**84%**	82%
Planned outage days				
Bruce A	**—**	84	**39**	84
Bruce B	**160**	25	**160**	74
Unplanned outage days				
Bruce A	**11**	45	**11**	105
Bruce B	**2**	—	**11**	—
Sales volumes (GWh)[1]				
Bruce A	**3,146**	2,047	**5,965**	4,574
Bruce B	**1,219**	2,096	**3,384**	4,020
	4,365	4,143	**9,349**	8,594
Realized sales price per MWh[3]				
Bruce A	**$73**	$72	**$73**	$71
Bruce B	**$53**	$55	**$53**	$55
Combined Bruce Power	**$66**	$62	**$64**	$62

1 Represents our 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B. 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. Bruce B realized sales prices per MWh includes revenues under the floor price mechanism and revenues from contract settlements.

Equity income from Bruce A increased by $93 million and $100 million for the three and six months ended June 30, 2015 compared to the same periods in 2014. These increases were mainly due to higher volumes resulting from fewer planned and unplanned outage days.

Equity income from Bruce B decreased by $51 million and $43 million for the three and six months ended June 30, 2015 compared to the same periods in 2014 mainly due to lower volumes resulting from higher planned outage days. All Bruce B units were removed from service in April 2015 to allow for inspection of the Bruce B vacuum building as mandated by the Canadian Nuclear Safety Commission to occur approximately once every decade. The outage, along with additional planned maintenance on Unit 6, was completed successfully during second quarter 2015.

Under a contract with the IESO, all of the output from Bruce A is sold at a fixed price/MWh which is adjusted annually on April 1 for inflation.

Bruce A fixed price	per MWh
April 1, 2015 - March 31, 2016	$73.42
April 1, 2014 - March 31, 2015	$71.70
April 1, 2013 - March 31, 2014	$70.99

Under the same contract, all output from Bruce B is subject to a floor price adjusted annually for inflation on April 1.

Bruce B floor price	per MWh
April 1, 2015 - March 31, 2016	$54.13
April 1, 2014 - March 31, 2015	$52.86
April 1, 2013 - March 31, 2014	$52.34

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the average spot price in a month exceeds the floor price. We expect 2015 spot power prices to be less than the floor price throughout 2015 and therefore no amounts received under the floor price mechanism in 2015 are expected to be repaid. Amounts received above the floor price in first quarter 2014 were repaid to the IESO in January 2015.

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

The contract also 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 fixed price, floor price or spot price as applicable under the contract.

Overall plant availability percentages in 2015 are expected to be in the mid 80s for Bruce A and Bruce B. In July 2015, additional planned outage work commenced on Bruce A Unit 4 and is expected to continue for approximately three months.

U.S. POWER

(unaudited - millions of US$)	three months ended June 30 2015	three months ended June 30 2014	six months ended June 30 2015	six months ended June 30 2014
Revenue				
Power[1]	**379**	311	**984**	1,054
Capacity	**88**	96	**155**	166
	467	407	**1,139**	1,220
Commodity purchases resold	**(271)**	(218)	**(747)**	(767)
Plant operating costs and other[2]	**(91)**	(109)	**(208)**	(289)
Exclude risk management activities[1]	**(41)**	8	**13**	10
Comparable EBITDA	**64**	88	**197**	174
Comparable depreciation and amortization	**(28)**	(27)	**(55)**	(54)
Comparable EBIT	**36**	61	**142**	120

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 June 30 2015	three months ended June 30 2014	six months ended June 30 2015	six months ended June 30 2014
Physical sales volumes (GWh)				
Supply				
Generation	**2,135**	2,006	**3,049**	3,244
Purchased	**4,211**	2,712	**8,881**	5,961
	6,346	4,718	**11,930**	9,205
Plant availability[1,2]	**77%**	89%	**69%**	87%

1 The percentage of time the plant was available to generate power, regardless of whether it was running.
2 Plant availability for the three and six months ended June 30 was lower in 2015 than the same periods in 2014 due to an unplanned outage at the Ravenswood facility.

U.S. Power - other information

(unaudited)	three months ended June 30 2015	three months ended June 30 2014	six months ended June 30 2015	six months ended June 30 2014
Average Spot Power Prices (US$ per MWh)				
New England[1]	25	40	55	93
New York[2]	28	41	51	88
Average New York[2] Spot Capacity Prices (US$ per KW-M)	12.92	15.81	10.63	12.72

1 New England ISO all hours Mass Hub price
2 Zone J in New York City where the Ravenswood plant operates

Comparable EBITDA for U.S. Power decreased US$24 million for the three months ended June 30, 2015 compared to the same period in 2014 primarily due to the net effect of:

- the timing of recognizing earnings on certain contracts in our power marketing business due to different power pricing profiles between the prices we charge our customers and the prices we pay for volumes purchased
- lower realized capacity prices in New York
- higher margins and higher sales to wholesale, commercial and industrial customers.

Comparable EBITDA for U.S. Power increased US$23 million for the six months ended June 30, 2015 compared to the same period in 2014 primarily due to the net effect of:

- higher margins and higher sales volumes to wholesale, commercial and industrial customers
- lower realized capacity prices in New York
- lower realized power prices and generation at our facilities in New York and New England partially offset by lower fuel costs.

The timing of recognizing earnings on certain contracts in our U.S. power marketing business is impacted by different power pricing profiles between the prices we charge our customers and the prices we pay for volumes purchased to fulfill our sales obligations over the term of the contracts. The costs on volumes purchased to fulfill power sales commitments to wholesale, commercial and industrial customers include the impact of certain contracts to purchase power over multiple periods at a flat price. Because the price we charge our customers is typically shaped to the market, the impact of these two contract pricing profiles has generally resulted in higher earnings in January to March, offset by lower earnings between April and December with overall positive margins realized over the term of the contracts. Due to increased natural gas and power prices experienced during winter 2014 and the impact on the pricing of our 2015 contracts in the New England market, these timing differences have been more significant in 2015. As discussed in our first quarter 2015 Report to Shareholders, the majority of the higher earnings in first quarter have been offset by lower earnings in second quarter.

Wholesale electricity prices in New York and New England were significantly lower for the three and six months ended June 30, 2015 compared to the same periods in 2014. In New England, spot power prices for the three and six months ended June 30, 2015 were 38 per cent and 41 per cent lower compared to the same periods in 2014. In New York City, spot power prices were 32 per cent and 42 per cent lower for the three and six months ended June 30, 2015 compared to the same periods in 2014. Spot capacity prices in New York City were, on average, 18 per cent and 16 per cent lower for the three and six months ended June 30, 2015 compared to the same periods in 2014. Reductions in fuel oil prices and increased availability of liquefied natural gas in winter 2015 helped to mitigate the impact of pipeline constraints and keep peak price excursions limited compared to winter 2014. Lower commodity prices and reduced price volatility contributed to higher margins on sales to wholesale, commercial and industrial customers by reducing the costs on volumes purchased to fulfill power sales commitments to these customers.

Physical sales volumes and purchased volumes sold to wholesale, commercial and industrial customers were higher than the same periods in 2014.

As at June 30, 2015, approximately 2,900 GWh or 58 per cent of U.S. Power's planned generation was contracted for the remainder of 2015 and 3,800 GWh or 40 per cent for 2016. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets. Power sales fluctuate based on customer usage.

NATURAL GAS STORAGE AND OTHER

Comparable EBITDA increased $4 million for the three months ended June 30, 2015 and decreased $20 million for six months ended June 30, 2015 compared to the same periods in 2014. The decrease in the six months ended June 30, 2015 was primarily due to decreased storage revenues as a result of lower realized natural gas price spreads. Extreme natural gas price volatility experienced in first quarter 2014 did not repeat in first quarter 2015.

Recent developments

NATURAL GAS PIPELINES

Canadian Regulated Pipelines

NGTL System
The NGTL System has approximately $6.8 billion of new supply and demand facilities under development. In second quarter 2015, we continued to advance several of these capital expansion projects and plan to file additional facilities applications for this program through the remainder of 2015. We have also received additional requests for firm receipt service that we anticipate will increase the overall capital spend on the NGTL System beyond the previously announced program and continue to work with our customers to best match their requirements for 2016, 2017 and 2018 in-service dates.

North Montney Mainline
On April 15, 2015, the NEB issued its report recommending the federal government approve the $1.7 billion North Montney Mainline project which will provide substantial new capacity on the NGTL System to meet the transportation requirements associated with rapidly increasing development of natural gas resources in the Montney supply basin in northeastern B.C. The project will connect Montney and other Western Canada Sedimentary Basin supply to both existing and new natural gas markets, including LNG markets.

The North Montney Mainline project will consist of two large diameter, 42-inch pipeline sections, Aitken Creek and Kahta, totaling approximately 301 km (187 miles) in length, and associated metering facilities, valve sites and compression facilities. The project will also include an interconnection with our proposed Prince Rupert Gas Transmission Project to provide natural gas supply to the proposed Pacific NorthWest (PNW) LNG liquefaction and export facility near Prince Rupert, B.C. We expect to have the Aitken Creek Section in service in late 2016 and the Kahta Section in service in 2017.

The NEB also approved the applied-for, rolled-in tolling design for the project costs during a transition period, subject to certain conditions which we are reviewing. Following the transition period, we will have the option of applying to the NEB for a revised tolling methodology, or the ability to implement stand-alone tolling on the project. We will engage shippers to determine an appropriate approach that best meets market requirements.

The Federal Government approved the recommendations of the report from the NEB and, on June 11, 2015, the NEB issued a Certificate of Public Convenience and Necessity to proceed with the project, subject to certain terms and conditions. Under one of these conditions, construction on the North Montney Mainline Project can only begin after a confirmation of FID has been made on the proposed PNW LNG project and we are proceeding with construction on PRGT.

Canadian Mainline

Canadian Mainline 2015-2020 Mainline Transportation Tolls Compliance Filing
On March 31, 2015, we submitted a compliance toll filing in response to direction from the NEB's RH-001-2014 Decision issued in November 2014. On June 12, 2015, the NEB approved the applied-for compliance tolls, as filed. These final tolls became effective on July 1, 2015 which allowed, among other things, the recording of incentive earnings as approved by the NEB.

Kings North Connection Project
On June 2, 2015, the NEB approved construction of the King's North Connection project to expand gas transmission capacity in the greater Toronto area and provide shippers with the flexibility to source growing supplies of Marcellus gas from the U.S. Northeast. The project is expected to cost approximately $220 million and is anticipated to be in-service by third quarter 2016.

U.S. Pipelines

Sale of GTN Pipeline to TC PipeLines, LP
On April 1, 2015, we closed the sale of our remaining 30 per cent interest in Gas Transmission Northwest LLC (GTN) to our master limited partnership, TC PipeLines, LP for an aggregate purchase price of US$446 million plus a purchase price adjustment of US$11 million. The US$457 million sale was comprised of US$264 million in cash, the assumption of US$98 million in proportional GTN debt and US$95 million of new Class B units of TC PipeLines, LP. The Class B units entitle us to a cash distribution based on 30 per cent of GTN's annual cash distribution after certain thresholds are achieved, namely 100 per cent of distributions above US$20 million in the first five years and 25 per cent of distributions above US$20 million in subsequent years.

LNG Pipeline Projects

Prince Rupert Gas Transmission
In second quarter 2015, we received six of 11 pipeline and facilities permits to build and operate the Prince Rupert Gas Transmission pipeline project from the B.C. Oil and Gas Commission (BC OGC). We anticipate decisions on the remaining BC OGC permits in third quarter 2015.

We continued our engagement with Aboriginal groups along the pipeline route and during the quarter announced the signing of project agreements with Gitanyow First Nation, Kitselas First Nation, Lake Babine Nation, Doig River First Nation, Halfway River First Nation and Yekooche First Nation.

On June 11, 2015, PNW LNG announced a positive FID for the proposed liquefaction and export facility, subject to two conditions. The first condition is approval by the Legislative Assembly of B.C. of a Project Development Agreement between PNW LNG and the Province of B.C. This condition was satisfied in mid-July 2015. The second condition is a positive regulatory decision on PNW LNG’s environmental assessment by the Government of Canada.

Subject to successful completion of the regulatory process for PRGT, we remain on target to begin construction following confirmation of a FID by PNW LNG. The in-service date for PRGT is estimated to be 2020 but will be aligned with PNW LNG’s liquefaction facility timeline.

Coastal GasLink
We have received eight of ten pipeline and facilities permits from the BC OGC and anticipate receiving the remaining two permits in third quarter 2015. We are continuing our engagement with Aboriginal groups along the pipeline route and, on June 29, 2015, we announced the signing of project agreements with Wet’suwet’en First Nation, Skin Tyee Nation, Nee-Tahi-Buhn Band, Yekooche First Nation, Doig River First Nation and Halfway River First Nation, all of northern B.C.

LIQUIDS PIPELINES

Houston Lateral and Terminal
Construction continues on the 77 km (48 mile) Houston Lateral pipeline and tank terminal which will extend the Keystone Pipeline System to Houston, Texas refineries. The terminal is expected to have initial storage capacity for 700,000 barrels of crude oil. The pipeline and terminal are expected to be completed in fourth quarter 2015.

On April 14, 2015, we, along with Magellan Midstream Partners L.P. (Magellan), announced a joint development agreement to connect our Houston Terminal to Magellan's East Houston Terminal. We will own 50 per cent of this US$50 million pipeline project which will enhance connections to the Houston market for our Keystone Pipeline System. Subject to definitive agreements and receipt of necessary permits and approvals, the pipeline is expected to be operational in late 2016.

Keystone XL
In January 2015, the DOS re-initiated the national interest review and requested the eight federal agencies with a role in the review to complete their consideration of whether Keystone XL serves the national interest. All of the agency comments were submitted.

On February 2, 2015, the U.S. Environmental Protection Agency (EPA) posted a comment letter to its website suggesting that, among other things, the FSEIS issued by the DOS had not fully and completely assessed the environmental impacts of Keystone XL and that, at lower crude oil prices, Keystone XL may increase the rates of oil sands production and greenhouse gas emissions. On February 10, 2015, we sent a letter to the DOS refuting these and other comments in the EPA letter and offered to work with the DOS to ensure it has all the relevant information to allow it to reach a decision to approve Keystone XL.

On February 12, 2015, Nebraska county courts granted temporary injunctions that were negotiated between us and landowners' counsel which prevent Keystone from proceeding with condemnation cases until the underlying constitutional litigation is resolved. A renewed challenge to the constitutionality of the statute under which the Governor approved the re-route in the state is pending in a Nebraska District Court.

On February 24, 2015, U.S. President Obama vetoed Congressional legislation that would have granted us authority to construct Keystone XL across the international border. The U.S. President stated that the legislation circumvented a final DOS assessment. The timing and ultimate resolution of Keystone XL's pending application for a Presidential Permit remains uncertain.

On June 29, 2015, we sent a letter to the DOS with additional evidence demonstrating that Canada is taking strong steps toward managing carbon emissions.

The South Dakota Public Utility Commission has scheduled a hearing in third quarter 2015 on our request to certify our existing permit authority in that state.

The estimated capital cost for Keystone XL is expected to be approximately US$8.0 billion. As of June 30, 2015, we have invested US$2.4 billion in the project and have also capitalized interest in the amount of US$0.4 billion.

Energy East Pipeline

On April 2, 2015, we announced that the marine and associated tank terminal in Cacouna, Québec will not be built as a result of the recommended reclassification of beluga whales as an endangered species. We are currently evaluating other options and amendments to the project are expected to be submitted to the NEB in fourth quarter 2015. The NEB has continued to process the application in the interim.

The alteration to the project scope and further refinement of the project schedule is expected to result in an in-service date of 2020. The original $12 billion cost estimate is expected to increase due to further scope refinement as we consult with stakeholders and escalation of construction costs as the project schedule is refined.

Binding long-term contracts of approximately one million Bbl/d for the 1.1 million Bbl/d pipeline have been secured and discussions with shippers continue.

Heartland Pipeline and TC Terminals

On May 7, 2015, the Alberta Energy Regulator issued a permit for construction of the Heartland Pipeline. The in-service date of the project will be aligned to meet market requirements for incremental capacity between the Heartland region near Edmonton, Alberta and Hardisty, Alberta.

Crude oil prices continue to remain low, prompting many producers to cut capital spending and delay oil sands projects in western Canada. In its 2015 Crude Oil Forecast, Markets and Transportation report, the Canadian Association of Petroleum Producers estimated WCSB crude oil production will continue to grow but at a slower pace than previously anticipated. Our liquids pipelines projects are supported by long-term contracts. However, with the slowing in growth of crude oil production, our intra-Alberta projects may experience a similar slowing pace of growth to align with the market.

Upland Pipeline

On April 22, 2015, we filed an application to obtain a U.S. Presidential Permit for the Upland Pipeline. The US$600 million Upland Pipeline is a 400 km (240 mile) crude oil pipeline which will provide transportation from, and between, multiple points in North Dakota and interconnect with the Energy East Pipeline at Moosomin, Saskatchewan. Subject to regulatory approvals, we anticipate the Upland Pipeline to be in service in 2020. The commercial contracts we have executed for Upland Pipeline are conditioned on the Energy East pipeline project proceeding.

ENERGY

Alberta Greenhouse Gas Emissions

On June 25, 2015, the Alberta government announced a renewal and change to the Specified Gas Emitters Regulations (SGER) in Alberta. Since 2007 under the SGER, established industrial facilities with GHG emissions above a certain threshold are required to reduce their emissions by 12 per cent below an average intensity baseline and a carbon levy of $15 per tonne is placed on emissions above this target. The changed regulations include an increase in the emissions reductions target to 15 per cent in 2016 and 20 per cent in 2017, along with an increase in the carbon levy to $20 per tonne in 2016 and $30 per tonne in 2017. Our Sundance and Sheerness PPA's are subject to this regulation. Our significant inventory of carbon offset credits are expected to mitigate the majority of these increased costs. The remaining compliance costs are expected to be recovered through increased market pricing and contract flow through provisions.

Ravenswood

In late May 2015, the 972 MW Unit 30 at the Ravenswood Generating Station returned to service after a September 2014 unplanned outage which resulted from a problem with the generator associated with the high pressure turbine.

Other income statement items

The following are reconciliations and related analyses of our non-GAAP measures to the equivalent GAAP measures for other income statement items.

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2015**	**2014**	**2015**	**2014**
Comparable interest on long-term debt (including interest on junior subordinated notes)				
Canadian-dollar denominated	**(106)**	(113)	**(215)**	(227)
U.S. dollar-denominated (US$)	**(228)**	(216)	**(446)**	(423)
Foreign exchange impact	**(57)**	(19)	**(105)**	(41)
	(391)	(348)	**(766)**	(691)
Other interest and amortization expense	**(11)**	(12)	**(24)**	(22)
Capitalized interest	**71**	63	**141**	142
Comparable interest expense	**(331)**	(297)	**(649)**	(571)
Specific items[1]	**—**	—	**—**	—
Interest expense	**(331)**	(297)	**(649)**	(571)

1 There were no specific items in any of these periods.

Comparable interest expense increased by $34 million and $78 million for the three and six months ended June 30, 2015 compared to the same periods in 2014 due to the net effect of:

- higher interest expense due to debt issues of:
  - US$750 million in May 2015
  - US$750 million in March 2015
  - US$350 million in March 2015 by TC PipeLines, LP
  - US$750 million in January 2015
  - US$1.25 billion in February 2014
  - 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.

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2015**	**2014**	**2015**	**2014**
Comparable interest income and other expense	**51**	29	**66**	23
Specific items (pre-tax):				
Risk management activities	**30**	25	**1**	23
Interest income and other expense	**81**	54	**67**	46

Comparable interest income and other expense increased by $22 million and $43 million for the three and six months ended June 30, 2015 compared to the same periods in 2014. This is the net result of:

- increased AFUDC related to our rate-regulated projects, primarily the Energy East Pipeline and our Mexico pipelines
- higher realized losses in 2015 compared to 2014 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar denominated income
- the impact of a strengthening U.S. dollar on the translation of foreign currency denominated working capital.

(unaudited - millions of $)	three months ended June 30 2015	2014	six months ended June 30 2015	2014
Comparable income tax expense	**(185)**	(162)	**(432)**	(386)
Specific items:				
Alberta corporate income tax rate increase	**(34)**	—	**(34)**	—
Restructuring costs	**4**	—	**4**	—
Cancarb gain on sale	**—**	(9)	**—**	(9)
Niska contract termination	**—**	10	**—**	10
Risk management activities	**(35)**	(4)	**5**	(1)
Income tax expense	**(250)**	(165)	**(457)**	(386)

Comparable income tax expense increased by $23 million and $46 million for the three and six months ended June 30, 2015 compared to the same periods in 2014. The increase was mainly the result of higher pre-tax earnings in 2015 compared to 2014 and changes in the proportion of income earned between Canadian and foreign jurisdictions, partially offset by lower flow-through taxes in 2015 on Canadian regulated pipelines.

(unaudited - millions of $)	three months ended June 30 2015	2014	six months ended June 30 2015	2014
Net income attributable to non-controlling interests	**(40)**	(31)	**(99)**	(85)
Preferred share dividends	**(25)**	(25)	**(48)**	(48)

Net income attributable to non-controlling interests increased by $9 million and $14 million for the three and six months ended June 30, 2015 compared to the same periods in 2014 primarily due to the sale of our remaining 30 per cent direct interests in GTN in April 2015 and Bison in October 2014 to TC PipeLines, LP and the impact of a stronger U.S. dollar on the Canadian dollar equivalent earnings from TC PipeLines, LP.

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, proceeds from the sale of U.S. natural gas pipeline assets to TC PipeLines, LP, cash on hand and substantial committed credit facilities.

CASH PROVIDED BY OPERATING ACTIVITIES

(unaudited - millions of $)	three months ended June 30		six months ended June 30	
	2015	**2014**	**2015**	**2014**
Funds generated from operations[1]	**1,061**	917	**2,214**	2,019
(Increase)/decrease in operating working capital	**(92)**	202	**(485)**	79
Net cash provided by operations	**969**	1,119	**1,729**	2,098

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

At June 30, 2015, our current assets were $3.7 billion and current liabilities were $7.2 billion, leaving us with a working capital deficit of $3.5 billion compared to $4.0 billion at December 31, 2014. 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 $6.0 billion of unutilized, unsecured credit facilities.

CASH USED IN INVESTING ACTIVITIES

(unaudited - millions of $)	three months ended June 30		six months ended June 30	
	2015	**2014**	**2015**	**2014**
Capital expenditures	**(966)**	(893)	**(1,772)**	(1,637)
Capital projects under development	**(172)**	(193)	**(335)**	(297)
Equity investments	**(105)**	(40)	**(198)**	(129)
Proceeds from sale of assets, net of transaction costs	**—**	187	**—**	187
Deferred amounts and other	**89**	25	**314**	72
Net cash used in investing activities	**(1,154)**	(914)	**(1,991)**	(1,804)

Capital expenditures in 2015 were primarily related to:
- the expansion of the NGTL System
- construction of Mexico pipelines
- construction of the Northern Courier pipeline
- continued work on the ANR pipeline expansion
- construction of the Napanee power project.

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

Equity investments have increased in 2015 compared to 2014 primarily due to our investment in Grand Rapids.

CASH (USED IN)/PROVIDED BY FINANCING ACTIVITIES

(unaudited - millions of $)	three months ended June 30 2015	three months ended June 30 2014	six months ended June 30 2015	six months ended June 30 2014
Junior subordinated debt issued, net of issue costs	**917**	—	**917**	—
Long-term debt issued, net of issue costs	**84**	16	**2,361**	1,380
Repayment of long-term debt	**(867)**	(205)	**(1,883)**	(982)
Notes payable (repaid)/issued, net	**(749)**	225	**(470)**	(522)
Dividends and distributions paid	**(446)**	(412)	**(863)**	(802)
Common shares issued, net of issue costs	**1**	6	**11**	16
Partnership units of subsidiary issued, net of issue costs	**27**	—	**31**	—
Preferred shares issued, net of issue costs	**—**	—	**243**	440
Preferred shares of subsidiary redeemed	**—**	—	**—**	(200)
Net cash (used in)/provided by financing activities	**(1,033)**	(370)	**347**	(670)

LONG-TERM DEBT ISSUED

Company (unaudited - millions of $)	Issue date	Type	Maturity date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	July 2015	Medium-Term Notes	July 2025	750	3.30%
	March 2015	Senior Unsecured Notes	March 2045	US 750	4.60%
	January 2015	Senior Unsecured Notes	January 2018	US 500	1.875%
	January 2015	Senior Unsecured Notes	January 2018	US 250	Floating
TC PIPELINES, LP					
	March 2015	Senior Unsecured Notes	March 2025	US 350	4.375%
GAS TRANSMISSION NORTHWEST LLC					
	June 2015	Unsecured Term Loan	June 2019	US 75	Floating

JUNIOR SUBORDINATED DEBT ISSUED

Company (unaudited - millions of $)	Issue date	Type	Maturity date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	May 2015	Junior subordinated unsecured notes[1]	May 2075	US 750	5.875%[2]

1 The Junior subordinated unsecured notes are subordinated in right of payment to existing and future senior indebtedness or other obligations of TCPL and are callable at TCPL's option at any time on or after May 20, 2025 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

2 The Junior subordinated notes were issued to TransCanada Trust. The interest rate is fixed at 5.875 per cent per annum and will reset starting May 2025 until May 2045 to the three month LIBOR plus 3.778 per cent per annum; from May 2045 to May 2075 the interest rate will reset to the three month LIBOR plus 4.528 per cent per annum.

TransCanada Trust (the Trust), our 100 per cent owned financing trust subsidiary of TCPL, issued US$750 million Trust Notes - Series 2015-A (Trust Notes) to third party investors with a fixed interest rate of 5.625 per cent for the first ten years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to us in US$750 million junior subordinated notes of TCPL at a rate of 5.875 per cent which includes a 0.25 per cent administration charge. While the obligations of the Trust are fully and unconditionally guaranteed by TCPL, on a subordinated basis, the Trust is not consolidated in our financial statements as TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are receivables from TCPL.

LONG-TERM DEBT RETIRED

Company (unaudited - millions of $)	Retirement date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	June 2015	Senior Unsecured Notes	US 500	3.40%
	March 2015	Senior Unsecured Notes	US 500	0.875%
	January 2015	Senior Unsecured Notes	US 300	4.875%
GAS TRANSMISSION NORTHWEST LLC				
	June 2015	Senior Unsecured Notes	US 75	5.09%

PREFERRED SHARE ISSUANCE AND CONVERSION

In June 2015, holders of 5.5 million Series 3 cumulative redeemable first preferred shares exercised their option to convert to Series 4 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 1.28 per cent which will reset every quarter going forward. The fixed dividend rate on the remaining Series 3 preferred shares was reset for five years at 2.152 per cent per annum.

In March 2015, we completed a public offering of 10 million Series 11 cumulative redeemable first preferred shares at $25 per share resulting in gross proceeds of $250 million. The Series 11 preferred shareholders will have the right to convert their Series 11 preferred shares into Series 12 cumulative redeemable first preferred shares on November 30, 2020 and on November 30 of every fifth year thereafter. The holders of Series 12 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at an annual rate equal to the applicable 90-day Government of Canada treasury bill rate plus 2.96 per cent.

The following table summarizes the impact of the above transactions on the Series 3, 4 and 11 preferred shares at June 30, 2015:

(unaudited - millions of Canadian $, unless noted otherwise)	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	Right to convert into
Cumulative first preferred shares						
Series 3	8,533	2.152%	0.538	$25.00	June 30, 2020	Series 4
Series 4	5,467	Floating[3]	Floating	$25.50	June 30, 2020	Series 3
Series 11	10,000	3.80%	0.95	$25.00	November 30, 2020	Series 12

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 4 preferred shares. The holders of Series 4 preferred shares are entitled to receive quarterly, floating rate, cumulative, preferred dividends 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.
3 Commencing June 30, 2015, the floating quarterly dividend rate for the Series 4 preferred shares is 1.945 per cent and will reset every quarter going forward.

The net proceeds of the above debt and Series 11 preferred share offerings were used for general corporate purposes and to reduce short-term indebtedness.

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

From January 1 to June 30, 2015, 0.4 million common units were issued under the TC PipeLines, LP's ATM program generating net proceeds of approximately US$25 million. Our ownership interest in TC PipeLines, LP will decrease as a result of issuances under the ATM program.

DIVIDENDS

On July 30, 2015, we declared quarterly dividends as follows:

Quarterly dividend on our common shares
$0.52 per share
Payable on October 30, 2015 to shareholders of record at the close of business on September 30, 2015

Quarterly dividends on our preferred shares	
Series 1	$0.204125
Series 2	$0.16289041
Series 3	$0.1345
Series 4	$0.12256164
Payable on September 30 to shareholders of record at the close of business on August 31, 2015	
Series 5	$0.275
Series 7	$0.25
Series 9	$0.265625
Payable on October 30, 2015 to shareholders of record at the close of business on September 30, 2015	
Series 11	$0.2375
Payable on August 31, 2015 to shareholders of record at the close of business on August 12, 2015	

SHARE INFORMATION

as at July 27, 2015		
Common shares	**Issued and outstanding**	
	709 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	14 million	Series 6 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
Options to buy common shares	**Outstanding**	**Exercisable**
	10 million	6 million

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.

At June 30, 2015, we had approximately $7 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 credit facility that supports TCPL's Canadian commercial paper program	December 2019
US$1.0 billion	US$1.0 billion	TCPL USA	Committed, syndicated, revolving, extendible credit facility that is used for TCPL USA general corporate purposes	November 2015
US$1.0 billion	US$1.0 billion	TransCanada American Investments Ltd. (TAIL)	Committed, syndicated, revolving, extendible credit facility that supports TAIL's U.S. commercial paper program in the U.S.	November 2015
$1.4 billion	$0.6 billion	TCPL, TCPL USA	Demand lines for issuing letters of credit and as a source of additional liquidity. At June 30, 2015, we had $0.8 billion outstanding in letters of credit under these lines	Demand

At June 30, 2015, our operated affiliates had $0.6 billion of undrawn capacity on committed credit facilities.

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

CONTRACTUAL OBLIGATIONS

Our capital commitments have decreased by approximately $0.2 billion since December 31, 2014 as a result of the completion or advancement of capital projects partially offset by new commitments for the Napanee generating facility. Our other purchase obligations have increased by approximately $0.1 billion since December 31, 2014 primarily due to an increase in commodity purchase obligations and information technology and communication contracts. There were no other material changes to our contractual obligations in second quarter 2015 or to payments due in the next five years or after. See the MD&A in our 2014 Annual Report for more information about our contractual obligations.

Financial risks and financial instruments

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

See our 2014 Annual Report for more information about the risks we face in our business. Our risks have not changed substantially since December 31, 2014.

LIQUIDITY RISK

We manage our liquidity risk by continuously forecasting our cash requirements for a rolling twelve 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 June 30, 2015, we had not incurred any significant credit losses and had no significant amounts past due or impaired. We had a credit risk concentration due from a counterparty of $222 million (US$178 million) and $258 million (US$222 million) at June 30, 2015 and December 31, 2014, respectively. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's investment grade parent company.

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 and floating rate preferred shares (Series 2 and Series 4) which subject us to interest rate cash flow risk. We use interest rate swaps to help manage this risk.

Average exchange rate - U.S. to Canadian dollars

three months ended June 30, 2015	**1.23**
three months ended June 30, 2014	1.09
six months ended June 30, 2015	**1.24**
six months ended June 30, 2014	1.10

The impact of changes in the value of the U.S. dollar on our U.S. dollar-denominated operations is significantly offset by other U.S. dollar-denominated items, as set out in the table below.

Significant U.S. dollar-denominated amounts

(unaudited - millions of US$)	three months ended June 30 2015	three months ended June 30 2014	six months ended June 30 2015	six months ended June 30 2014
U.S. and International Natural Gas Pipelines comparable EBIT	**137**	140	**378**	351
U.S. Liquids Pipelines comparable EBIT	**158**	133	**307**	262
U.S. Power comparable EBIT	**36**	61	**142**	120
Interest expense on U.S. dollar-denominated long-term debt	**(228)**	(216)	**(446)**	(423)
Capitalized interest on U.S. dollar-denominated capital expenditures	**29**	43	**60**	95
U.S. non-controlling interests and other	**(54)**	(53)	**(133)**	(132)
	78	108	**308**	273

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 and foreign exchange forward contracts. The fair values and notional amounts for the derivatives designated as a net investment hedge were as follows:

(unaudited - millions of $)	June 30, 2015 Fair value[1]	June 30, 2015 Notional or principal amount	December 31, 2014 Fair value[1]	December 31, 2014 Notional or principal amount
Asset/(liability)				
U.S. dollar cross-currency interest rate swaps				
(maturing 2015 to 2019)[2]	**(560)**	**US 2,500**	(431)	US 2,900
U.S. dollar foreign exchange forward contracts				
(maturing 2015)	**(39)**	**US 1,572**	(28)	US 1,400
	(599)	**US 4,072**	(459)	US 4,300

1 Fair values equal carrying values.
2 Net income in the three and six months ended June 30, 2015 included net realized gains of $2 million and $5 million, respectively, (2014 - gains of $5 million and $11 million, respectively) related to the interest component of cross-currency swaps settlements.

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

(unaudited - millions of $)	June 30, 2015	December 31, 2014
Carrying value	**19,500 (US 15,600)**	17,000 (US 14,700)
Fair value	**21,400 (US 17,200)**	19,000 (US 16,400)

The balance sheet classification of the fair value of derivatives used to hedge our net investment in foreign operations is as follows:

(unaudited - millions of $)	June 30, 2015	December 31, 2014
Other current assets	**23**	5
Intangible and other assets	**1**	1
Accounts payable and other	**(269)**	(155)
Other long-term liabilities	**(354)**	(310)
	(599)	(459)

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.

Non-derivative financial instruments

Fair value of non-derivative financial instruments

The fair value of our 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 has been estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data providers.

Available for sale assets are recorded at fair value which is calculated using quoted market prices where available. Certain non-derivative financial instruments including 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 financial instruments.

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 expense 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.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipelines exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, can be recovered or refunded through the tolls charged by us. As a result, these gains and losses are deferred as regulatory assets or regulatory liabilities and are refunded to or collected from the ratepayers in subsequent years when the derivative settles.

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 power and natural gas 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. Credit risk has been taken into consideration when calculating the fair value of derivative instruments.

Balance sheet presentation of derivative instruments

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

(unaudited - millions of $)	June 30, 2015	December 31, 2014
Other current assets	**369**	409
Intangible and other assets	**134**	93
Accounts payable and other	**(775)**	(749)
Other long-term liabilities	**(531)**	(411)
	(803)	(658)

The effect of derivative instruments on the condensed consolidated statement of income

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $, pre-tax)	2015	2014	2015	2014
Derivative instruments held for trading[1]				
Amount of unrealized gains/(losses) in the period				
Power	**27**	6	**1**	15
Natural gas	**(4)**	(14)	**(4)**	(21)
Foreign exchange	**30**	25	**1**	23
Amount of realized (losses)/gains in the period				
Power	**(23)**	(3)	**(33)**	(31)
Natural gas	**(10)**	(4)	**1**	46
Foreign exchange	**(10)**	(1)	**(53)**	(18)
Derivative instruments in hedging relationships[2,3]				
Amount of realized (losses)/gains in the period				
Power	**(113)**	(4)	**(97)**	188
Interest	**2**	1	**4**	2
Gains/(losses) on ineffective portion in the period				
Power	**56**	3	**(7)**	(10)

1 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell power and natural gas are included net in energy 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 expense, respectively.

2 For the three and six months ended June 30, 2015, net realized gains on fair value hedges were $2 million and $4 million, respectively, (2014 - gains of $2 million and $3 million, respectively) and were included in interest expense. For the three and six months ended June 30, 2015 and 2014, we did not record any amounts in net income related to ineffectiveness for fair value hedges.

3 The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to energy revenues, interest expense and interest income and other expense as appropriate, as the original hedged item settles. For the three and six months ended June 30, 2015 and 2014, there were no gains or losses included in net income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

Derivatives in cash flow hedging relationships

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $, pre-tax)	**2015**	2014	**2015**	2014
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]				
Power	**(50)**	(7)	**(29)**	34
Natural gas	**—**	(1)	**—**	(1)
Foreign exchange	**—**	—	**—**	10
Interest	**—**	(1)	**—**	(1)
	(50)	(9)	**(29)**	42
Reclassification of (losses)/gains on derivative instruments from AOCI to net income (effective portion)[1]				
Power[2]	**(21)**	(1)	**48**	(109)
Natural gas[2]	**—**	2	**—**	2
Interest[3]	**4**	3	**8**	8
	(17)	4	**56**	(99)
Gains/(losses) on derivative instruments recognized in net income (ineffective portion)				
Power	**56**	3	**(7)**	(10)
	56	3	**(7)**	(10)

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

Credit risk related contingent features of derivative instruments

Derivatives contracts 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).

Based on contracts in place and market prices at June 30, 2015, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $4 million (December 31, 2014 - $15 million), with collateral provided in the normal course of business of nil (December 31, 2014 – nil). If the credit-risk-related contingent features in these agreements had been triggered on June 30, 2015, we would have been required to provide collateral of $4 million (December 31, 2014 – $15 million) to our counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

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

Other information

CONTROLS AND PROCEDURES

Management, including our President and CEO and our CFO, evaluated the effectiveness of our disclosure controls and procedures as at June 30, 2015, as required by the Canadian securities regulatory authorities and by the SEC, and concluded that our disclosure controls and procedures are effective at a reasonable assurance level.

There were no changes in second quarter 2015 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 2014 Annual Report.

Our significant accounting policies have remained unchanged since December 31, 2014 other than described below. You can find a summary of our significant accounting policies in our 2014 Annual Report.

Changes in accounting policies for 2015

Reporting discontinued operations
In April 2014, the FASB issued amended guidance on the reporting of discontinued operations. The criteria of what will qualify as a discontinued operation has changed and there are expanded disclosures required. This new guidance was applied prospectively from January 1, 2015 and there was no impact on our consolidated financial statements as a result of applying this new standard.

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 agreed to defer 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 ASU and have not yet determined the effect on our consolidated financial statements.

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 is effective from January 1, 2016 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.

Consolidation
In February 2015, the FASB issued new guidance on consolidation analysis. This update requires that entities reevaluate whether they should consolidate certain legal entities and eliminates the presumption that a general partner should consolidate a limited partnership. This new guidance is effective from January 1, 2016 and will be applied retrospectively. We are currently evaluating the impact of the adoption of this ASU and have not yet determined the effect on our consolidated financial statements.

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 is effective January 1, 2016 and will be applied retrospectively. The application of this amendment will result in a reclassification of debt issuance costs currently recorded in intangible and other assets to an offset of their respective debt liabilities.

Reconciliation of non-GAAP measures

	three months ended June 30		six months ended June 30	
(unaudited - millions of $, except per share amounts)	**2015**	2014	**2015**	2014
EBITDA	**1,434**	1,279	**2,876**	2,664
Restructuring costs	**12**	—	**12**	—
Cancarb gain on sale	**—**	(108)	**—**	(108)
Niska contract termination	**—**	41	**—**	41
Non-comparable risk management activities affecting EBITDA	**(79)**	5	**10**	16
Comparable EBITDA	**1,367**	1,217	**2,898**	2,613
Comparable depreciation and amortization	**(440)**	(399)	**(874)**	(792)
Comparable EBIT	**927**	818	**2,024**	1,821
Other income statement items				
Comparable interest expense	**(331)**	(297)	**(649)**	(571)
Comparable interest income and other expense	**51**	29	**66**	23
Comparable income tax expense	**(185)**	(162)	**(432)**	(386)
Net income attributable to non-controlling interests	**(40)**	(31)	**(99)**	(85)
Preferred share dividends	**(25)**	(25)	**(48)**	(48)
Comparable earnings	**397**	332	**862**	754
Specific items (net of tax):				
Alberta corporate income tax rate increase	**(34)**	—	**(34)**	—
Restructuring costs	**(8)**	—	**(8)**	—
Cancarb gain on sale	**—**	99	**—**	99
Niska contract termination	**—**	(31)	**—**	(31)
Risk management activities[1]	**74**	16	**(4)**	6
Net income attributable to common shares	**429**	416	**816**	828
Comparable depreciation and amortization	**(440)**	(399)	**(874)**	(792)
Specific items	**—**	—	**—**	—
Depreciation and amortization	**(440)**	(399)	**(874)**	(792)
Comparable interest expense	**(331)**	(297)	**(649)**	(571)
Specific items	**—**	—	**—**	—
Interest expense	**(331)**	(297)	**(649)**	(571)
Comparable interest income and other expense	**51**	29	**66**	23
Specific items:				
Risk management activities[1]	**30**	25	**1**	23
Interest income and other expense	**81**	54	**67**	46
Comparable income tax expense	**(185)**	(162)	**(432)**	(386)
Specific items:				
Alberta corporate income tax rate increase	**(34)**	—	**(34)**	—
Restructuring costs	**4**	—	**4**	—
Cancarb gain on sale	**—**	(9)	**—**	(9)
Niska contract termination	**—**	10	**—**	10
Risk management activities[1]	**(35)**	(4)	**5**	(1)
Income tax expense	**(250)**	(165)	**(457)**	(386)

(unaudited - millions of $, except per share amounts)	three months ended June 30 2015	three months ended June 30 2014	six months ended June 30 2015	six months ended June 30 2014
Comparable earnings per common share	**$ 0.56**	$ 0.47	**$ 1.22**	$ 1.07
Specific items (net of tax):				
Alberta corporate income tax rate increase	**(0.05)**	—	**(0.05)**	—
Restructuring costs	**(0.01)**	—	**(0.01)**	—
Cancarb gain on sale	**—**	0.14	**—**	0.14
Niska contract termination	**—**	(0.04)	**—**	(0.04)
Risk management activities[1]	**0.10**	0.02	**(0.01)**	—
Net income per common share	**$ 0.60**	$ 0.59	**$ 1.15**	$ 1.17

1

Risk management activities (unaudited - millions of $)	three months ended June 30 2015	three months ended June 30 2014	six months ended June 30 2015	six months ended June 30 2014
Canadian Power	**29**	(2)	**7**	(2)
U.S. Power	**51**	(9)	**(17)**	(11)
Natural Gas Storage	**(1)**	6	**—**	(3)
Foreign exchange	**30**	25	**1**	23
Income tax attributable to risk management activities	**(35)**	(4)	**5**	(1)
Total gains/(losses) from risk management activities	**74**	16	**(4)**	6

Comparable EBITDA and EBIT by business segment

three months ended June 30, 2015 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	**807**	**316**	**351**	**(40)**	**1,434**
Restructuring costs	**—**	**—**	**—**	**12**	**12**
Non-comparable risk management activities affecting EBITDA	**—**	**—**	**(79)**	**—**	**(79)**
Comparable EBITDA	**807**	**316**	**272**	**(28)**	**1,367**
Comparable depreciation and amortization	**(282)**	**(66)**	**(84)**	**(8)**	**(440)**
Comparable EBIT	**525**	**250**	**188**	**(36)**	**927**

three months ended June 30, 2014 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	759	249	293	(22)	1,279
Cancarb gain on sale	—	—	(108)	—	(108)
Niska contract termination	—	—	41	—	41
Non-comparable risk management activities affecting EBITDA	—	—	5	—	5
Comparable EBITDA	759	249	231	(22)	1,217
Comparable depreciation and amortization	(263)	(54)	(77)	(5)	(399)
Comparable EBIT	496	195	154	(27)	818

six months ended June 30, 2015 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	**1,681**	**625**	**650**	**(80)**	**2,876**
Restructuring costs	**—**	**—**	**—**	**12**	**12**
Non-comparable risk management activities affecting EBITDA	**—**	**—**	**10**	**—**	**10**
Comparable EBITDA	**1,681**	**625**	**660**	**(68)**	**2,898**
Comparable depreciation and amortization	**(561)**	**(129)**	**(169)**	**(15)**	**(874)**
Comparable EBIT	**1,120**	**496**	**491**	**(83)**	**2,024**

six months ended June 30, 2014 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	1,607	490	627	(60)	2,664
Cancarb gain on sale	—	—	(108)	—	(108)
Niska contract termination	—	—	41	—	41
Non-comparable risk management activities affecting EBITDA	—	—	16	—	16
Comparable EBITDA	1,607	490	576	(60)	2,613
Comparable depreciation and amortization	(525)	(103)	(154)	(10)	(792)
Comparable EBIT	1,082	387	422	(70)	1,821

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

	2015		2014				2013	
(unaudited - millions of $, except per share amounts)	Second	First	Fourth	Third	Second	First	Fourth	Third
Revenues	**2,631**	2,874	2,616	2,451	2,234	2,884	2,332	2,204
Net income attributable to common shares	**429**	387	458	457	416	412	420	481
Comparable earnings	**397**	465	511	450	332	422	410	447
Share statistics								
Net income per common share - basic and diluted	**$0.60**	$0.55	$0.72	$0.63	$0.59	$0.58	$0.59	$0.68
Comparable earnings per share	**$0.56**	$0.66	$0.65	$0.64	$0.47	$0.60	$0.58	$0.63
Dividends declared per common share	**$0.52**	$0.52	$0.48	$0.48	$0.48	$0.48	$0.46	$0.46

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, annual revenues and net income are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income are 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 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 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

(unaudited - millions of Canadian $, except per share amounts)	three months ended June 30 2015	three months ended June 30 2014	six months ended June 30 2015	six months ended June 30 2014
Revenues				
Natural Gas Pipelines	**1,286**	1,154	**2,591**	2,369
Liquids Pipelines	**460**	366	**903**	725
Energy	**885**	714	**2,011**	2,024
	2,631	2,234	**5,505**	5,118
Income from Equity Investments	**119**	68	**256**	203
Operating and Other Expenses				
Plant operating costs and other	**767**	684	**1,521**	1,489
Commodity purchases resold	**426**	328	**1,107**	1,034
Property taxes	**123**	119	**257**	242
Depreciation and amortization	**440**	399	**874**	792
Gain on sale of assets	**—**	(108)	**—**	(108)
	1,756	1,422	**3,759**	3,449
Financial Charges				
Interest expense	**331**	297	**649**	571
Interest income and other expense	**(81)**	(54)	**(67)**	(46)
	250	243	**582**	525
Income before Income Taxes	**744**	637	**1,420**	1,347
Income Tax Expense				
Current	**26**	23	**94**	82
Deferred	**224**	142	**363**	304
	250	165	**457**	386
Net Income	**494**	472	**963**	961
Net income attributable to non-controlling interests	**40**	31	**99**	85
Net Income Attributable to Controlling Interests	**454**	441	**864**	876
Preferred share dividends	**25**	25	**48**	48
Net Income Attributable to Common Shares	**429**	416	**816**	828
Net Income per Common Share				
Basic and diluted	**$0.60**	$0.59	**$1.15**	$1.17
Dividends Declared per Common Share	**$0.52**	$0.48	**$1.04**	$0.96
Weighted Average Number of Common Shares (millions)				
Basic	**709**	708	**709**	708
Diluted	**710**	709	**710**	709

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

(unaudited - millions of Canadian $)	three months ended June 30 2015	three months ended June 30 2014	six months ended June 30 2015	six months ended June 30 2014
Net Income	**494**	472	**963**	961
Other Comprehensive Income, Net of Income Taxes				
Foreign currency translation (losses)/gains on net investment in foreign operations	**(137)**	(190)	**332**	50
Change in fair value of net investment hedges	**58**	79	**(208)**	(48)
Change in fair value of cash flow hedges	**(36)**	(4)	**(21)**	27
Reclassification to net income of gains and losses on cash flow hedges	**(11)**	2	**33**	(60)
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**10**	5	**17**	9
Other comprehensive income on equity investments	**4**	2	**7**	2
Other comprehensive (loss)/income (Note 9)	**(112)**	(106)	**160**	(20)
Comprehensive Income	**382**	366	**1,123**	941
Comprehensive income/(loss) attributable to non-controlling interests	**10**	(8)	**217**	90
Comprehensive Income Attributable to Controlling Interests	**372**	374	**906**	851
Preferred share dividends	**25**	25	**48**	48
Comprehensive Income Attributable to Common Shares	**347**	349	**858**	803

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of cash flows

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $)	**2015**	**2014**	**2015**	**2014**
Cash Generated from Operations				
Net income	**494**	472	**963**	961
Depreciation and amortization	**440**	399	**874**	792
Deferred income taxes	**224**	142	**363**	304
Income from equity investments	**(119)**	(68)	**(256)**	(203)
Distributed earnings received from equity investments	**145**	84	**280**	254
Employee post-retirement benefits expense, net of funding	**15**	2	**30**	12
Gain on sale of assets	**—**	(108)	**—**	(108)
Equity AFUDC	**(37)**	(14)	**(70)**	(19)
Unrealized (gains)/losses on financial instruments	**(109)**	(20)	**9**	(7)
Other	**8**	28	**21**	33
(Increase)/decrease in operating working capital	**(92)**	202	**(485)**	79
Net cash provided by operations	**969**	1,119	**1,729**	2,098
Investing Activities				
Capital expenditures	**(966)**	(893)	**(1,772)**	(1,637)
Capital projects under development	**(172)**	(193)	**(335)**	(297)
Equity investments	**(105)**	(40)	**(198)**	(129)
Proceeds from sale of assets, net of transaction costs	**—**	187	**—**	187
Deferred amounts and other	**89**	25	**314**	72
Net cash used in investing activities	**(1,154)**	(914)	**(1,991)**	(1,804)
Financing Activities				
Dividends on common shares	**(368)**	(340)	**(709)**	(665)
Dividends on preferred shares	**(24)**	(25)	**(46)**	(45)
Distributions paid to non-controlling interests	**(54)**	(47)	**(108)**	(92)
Notes payable (repaid)/issued, net	**(749)**	225	**(470)**	(522)
Junior subordinated debt issued, net of issue costs	**917**	—	**917**	—
Long-term debt issued, net of issue costs	**84**	16	**2,361**	1,380
Repayment of long-term debt	**(867)**	(205)	**(1,883)**	(982)
Common shares issued, net of issue costs	**1**	6	**11**	16
Preferred shares issued, net of issue costs	**—**	—	**243**	440
Partnership units of subsidiary issued, net of issue costs	**27**	—	**31**	—
Preferred shares of subsidiary redeemed	**—**	—	**—**	(200)
Net cash (used in)/provided by financing activities	**(1,033)**	(370)	**347**	(670)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(13)**	(17)	**16**	16
(Decrease)/increase in Cash and Cash Equivalents	**(1,231)**	(182)	**101**	(360)
Cash and Cash Equivalents				
Beginning of period	**1,821**	749	**489**	927
Cash and Cash Equivalents				
End of period	**590**	567	**590**	567

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		June 30, 2015	December 31, 2014
ASSETS			
Current Assets			
Cash and cash equivalents		**590**	489
Accounts receivable		**1,407**	1,313
Inventories		**286**	292
Other		**1,462**	1,446
		3,745	3,540
Plant, Property and Equipment,	net of accumulated depreciation of $20,603 and $19,563, respectively	**44,417**	41,774
Equity Investments		**5,735**	5,598
Regulatory Assets		**1,256**	1,297
Goodwill		**4,337**	4,034
Intangible and Other Assets		**3,107**	2,704
		62,597	58,947
LIABILITIES			
Current Liabilities			
Notes payable		**2,086**	2,467
Accounts payable and other		**2,570**	2,896
Accrued interest		**460**	424
Current portion of long-term debt		**2,107**	1,797
		7,223	7,584
Regulatory Liabilities		**730**	263
Other Long-Term Liabilities		**1,187**	1,052
Deferred Income Tax Liabilities		**5,721**	5,275
Long-Term Debt		**24,591**	22,960
Junior Subordinated Notes		**2,182**	1,160
		41,634	38,294
EQUITY			
Common shares, no par value		**12,214**	12,202
Issued and outstanding:	June 30, 2015 - 709 million shares		
	December 31, 2014 - 709 million shares		
Preferred shares		**2,499**	2,255
Additional paid-in capital		**166**	370
Retained earnings		**5,559**	5,478
Accumulated other comprehensive loss (Note 9)		**(1,193)**	(1,235)
Controlling Interests		**19,245**	19,070
Non-controlling interests		**1,718**	1,583
		20,963	20,653
		62,597	58,947

Contingencies and Guarantees (Note 13)

Subsequent Event (Note 14)

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of equity

	six months ended June 30	
(unaudited - millions of Canadian $)	2015	2014
Common Shares		
Balance at beginning of period	**12,202**	12,149
Shares issued on exercise of stock options	**12**	17
Balance at end of period	**12,214**	12,166
Preferred Shares		
Balance at beginning of period	**2,255**	1,813
Shares issued under public offering, net of issue costs	**244**	442
Balance at end of period	**2,499**	2,255
Additional Paid-In Capital		
Balance at beginning of period	**370**	401
Issuance of stock options, net of exercises	**5**	3
Dilution impact from TC PipeLines, LP units issued	**4**	—
Redemption of subsidiary's preferred shares	**—**	(6)
Impact of asset drop downs to TC Pipelines, LP	**(213)**	—
Balance at end of period	**166**	398
Retained Earnings		
Balance at beginning of period	**5,478**	5,096
Net income attributable to controlling interests	**864**	876
Common share dividends	**(737)**	(680)
Preferred share dividends	**(46)**	(48)
Balance at end of period	**5,559**	5,244
Accumulated Other Comprehensive Loss		
Balance at beginning of period	**(1,235)**	(934)
Other comprehensive income/(loss)	**42**	(25)
Balance at end of period	**(1,193)**	(959)
Equity Attributable to Controlling Interests	**19,245**	19,104
Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	**1,583**	1,611
Net income attributable to non-controlling interests		
TC PipeLines, LP	**89**	74
Preferred share dividends of TCPL	**—**	2
Portland	**10**	9
Other comprehensive income attributable to non-controlling interests	**118**	5
Issuance of TC PipeLines, LP units		
Proceeds, net of issue costs	**31**	—
Decrease in TransCanada's ownership of TC Pipelines, LP	**(6)**	—
Distributions declared to non-controlling interests	**(107)**	(92)
Redemption of subsidiary's preferred shares	**—**	(194)
Foreign exchange and other	**—**	(2)
Balance at end of period	**1,718**	1,413
Total Equity	**20,963**	20,517

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, 2014. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in TransCanada's 2014 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 2014 audited consolidated financial statements included in TransCanada's 2014 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, 2014, except as described in Note 2, Changes in accounting policies.

2. Changes in accounting policies

CHANGES IN ACCOUNTING POLICIES FOR 2015

Reporting discontinued operations

In April 2014, the FASB issued amended guidance on the reporting of discontinued operations. The criteria of what will qualify as a discontinued operation has changed and there are expanded disclosures required. This new guidance was applied prospectively from January 1, 2015 and there was no impact on the Company's consolidated financial statements as a result of applying this new standard.

FUTURE ACCOUNTING CHANGES

Revenue from contracts with customers

In May 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 agreed to defer 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 ASU and has not yet determined the effect on its consolidated financial statements.

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 is effective from January 1, 2016 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.

Consolidation

In February 2015, the FASB issued new guidance on consolidation analysis. This update requires that entities reevaluate whether they should consolidate certain legal entities and eliminates the presumption that a general partner should consolidate a limited partnership. This new guidance is effective from January 1, 2016 and will be applied retrospectively. The Company is currently evaluating the impact of the adoption of this ASU and has not yet determined the effect on its consolidated financial statements.

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 is effective January 1, 2016 and will be applied retrospectively. The application of this amendment will result in a reclassification of debt issuance costs currently recorded in intangible and other assets to an offset of their respective debt liabilities.

3. Segmented information

three months ended June 30	**Natural Gas Pipelines**		**Liquids Pipelines**		**Energy**		**Corporate**		**Total**	
(unaudited - millions of Canadian $)	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**
Revenues	**1,286**	1,154	**460**	366	**885**	714	**—**	—	**2,631**	2,234
Income from equity investments	**39**	37	**—**	—	**80**	31	**—**	—	**119**	68
Plant operating costs and other	**(432)**	(348)	**(128)**	(100)	**(167)**	(214)	**(40)**	(22)	**(767)**	(684)
Commodity purchases resold	**—**	—	**—**	—	**(426)**	(328)	**—**	—	**(426)**	(328)
Property taxes	**(86)**	(84)	**(16)**	(17)	**(21)**	(18)	**—**	—	**(123)**	(119)
Depreciation and amortization	**(282)**	(263)	**(66)**	(54)	**(84)**	(77)	**(8)**	(5)	**(440)**	(399)
Gain on sale of assets	**—**	—	**—**	—	**—**	108	**—**	—	**—**	108
Segmented earnings	**525**	496	**250**	195	**267**	216	**(48)**	(27)	**994**	880
Interest expense									**(331)**	(297)
Interest income and other expense									**81**	54
Income before income taxes									**744**	637
Income tax expense									**(250)**	(165)
Net income									**494**	472
Net income attributable to non-controlling interests									**(40)**	(31)
Net income attributable to controlling interests									**454**	441
Preferred share dividends									**(25)**	(25)
Net income attributable to common shares									**429**	416

six months ended June 30	Natural Gas Pipelines		Liquids Pipelines		Energy		Corporate		Total	
(unaudited - millions of Canadian $)	2015	2014	2015	2014	2015	2014	2015	2014	2015	2014
Revenues	**2,591**	2,369	**903**	725	**2,011**	2,024	**—**	—	**5,505**	5,118
Income from equity investments	**93**	89	**—**	—	**163**	114	**—**	—	**256**	203
Plant operating costs and other	**(827)**	(681)	**(239)**	(201)	**(375)**	(547)	**(80)**	(60)	**(1,521)**	(1,489)
Commodity purchases resold	**—**	—	**—**	—	**(1,107)**	(1,034)	**—**	—	**(1,107)**	(1,034)
Property taxes	**(176)**	(170)	**(39)**	(34)	**(42)**	(38)	**—**	—	**(257)**	(242)
Depreciation and amortization	**(561)**	(525)	**(129)**	(103)	**(169)**	(154)	**(15)**	(10)	**(874)**	(792)
Gain on sale of assets	**—**	—	**—**	—	**—**	108	**—**	—	**—**	108
Segmented earnings	**1,120**	1,082	**496**	387	**481**	473	**(95)**	(70)	**2,002**	1,872
Interest expense									**(649)**	(571)
Interest income and other expense									**67**	46
Income before income taxes									**1,420**	1,347
Income tax expense									**(457)**	(386)
Net income									**963**	961
Net income attributable to non-controlling interests									**(99)**	(85)
Net income attributable to controlling interests									**864**	876
Preferred share dividends									**(48)**	(48)
Net income attributable to common shares									**816**	828

TOTAL ASSETS

(unaudited - millions of Canadian $)	June 30, 2015	December 31, 2014
Natural Gas Pipelines	**28,559**	27,103
Liquids Pipelines	**17,657**	16,116
Energy	**14,679**	14,197
Corporate	**1,702**	1,531
	62,597	58,947

4. Pipeline abandonment costs

As a result of the NEB's Land Matters Consultation Initiative (LMCI), TransCanada is required to collect funds to cover estimated future pipeline abandonment costs for all NEB regulated Canadian pipelines. Amounts collected are included in regulatory liabilities on the condensed consolidated balance sheet. As at June 30, 2015, regulatory liabilities included $117 million (December 31, 2014 - nil) of estimated future abandonment costs on the condensed consolidated balance sheet.

Collected funds are placed in trusts that hold and invest the funds and are accounted for as restricted investments. As at June 30, 2015, intangible and other assets included $117 million (December 31, 2014 - nil) of LMCI restricted investments on the condensed consolidated balance sheet. Please refer to Note 11 for information on the fair values of these investments which are classified as available for sale.

5. Income taxes

At June 30, 2015, the total unrecognized tax benefit of uncertain tax positions was approximately $19 million (December 31, 2014 - $18 million). TransCanada recognizes interest and penalties related to income tax uncertainties in income tax expense. Included in income tax expense for the three and six months ended June 30, 2015 is nil for interest expense and nil for penalties (June 30, 2014 - $1 million and nil, respectively, of income for the reversal of interest expense and nil for penalties). At June 30, 2015, the Company had $5 million accrued for interest expense and nil accrued for penalties (December 31, 2014 - $5 million accrued for interest expense and nil for penalties).

The effective tax rates for the six-month periods ended June 30, 2015 and 2014 were 32 per cent and 29 per cent, respectively. The higher effective tax rate in 2015 was primarily the result of an increase in the Alberta statutory tax rate 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 six months ended June 30, 2015 as follows:

(unaudited - millions of Canadian $, unless noted otherwise)	Issue date	Type	Maturity date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	March 2015	Senior Unsecured Notes	March 2045	US 750	4.60%
	January 2015	Senior Unsecured Notes	January 2018	US 500	1.875%
	January 2015	Senior Unsecured Notes	January 2018	US 250	Floating
TC PIPELINES, LP					
	March 2015	Senior Unsecured Notes	March 2025	US 350	4.375%
GAS TRANSMISSION NORTHWEST LLC					
	June 2015	Unsecured Term Loan	June 2019	US 75	Floating

LONG-TERM DEBT RETIRED

The Company retired long-term debt in the six months ended June 30, 2015 as follows:

(unaudited - millions of Canadian $, unless noted otherwise)	Retirement date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	June 2015	Senior Unsecured Notes	US 500	3.40%
	March 2015	Senior Unsecured Notes	US 500	0.875%
	January 2015	Senior Unsecured Notes	US 300	4.875%
GAS TRANSMISSION NORTHWEST LLC				
	June 2015	Senior Unsecured Notes	US 75	5.09%

In the three and six months ended June 30, 2015, TransCanada capitalized interest related to capital projects of $71 million and $141 million, respectively (2014 - $63 million and $142 million, respectively).

7. Junior Subordinated Notes

JUNIOR SUBORDINATED DEBT ISSUED

(unaudited - millions of Canadian $, unless noted otherwise)	Issue date	Type	Maturity date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED	May 2015	Junior subordinated unsecured notes[1]	May 2075	US 750	5.875%[2]

1 The Junior subordinated unsecured notes are subordinated in right of payment to existing and future senior indebtedness or other obligations of TCPL and are callable at TCPL's option at any time on or after May 20, 2025 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

2 The Junior subordinated notes were issued to TransCanada Trust. The interest rate is fixed at 5.875 per cent per annum and will reset starting May 2025 until May 2045 to the three month LIBOR plus 3.778 per cent per annum; from May 2045 to May 2075 the interest rate will reset to the three month LIBOR plus 4.528 per cent per annum.

TransCanada Trust (the Trust), a 100 per cent owned financing trust subsidiary of TCPL, issued US$750 million Trust Notes - Series 2015-A (Trust Notes) to third party investors with a fixed interest rate of 5.625 per cent for the first ten years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL in US$750 million junior subordinated notes of TCPL at a rate of 5.875 per cent which includes a 0.25 per cent administration charge. While the obligations of the Trust are fully and unconditionally guaranteed by TCPL, on a subordinated basis, the Trust is not consolidated in TransCanada's financial statements because TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are receivables from TCPL.

8. Equity and share capital

In June 2015, holders of 5.5 million Series 3 cumulative redeemable first preferred shares exercised their option to convert to Series 4 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 1.28 per cent which will reset every quarter going forward. The fixed dividend rate on the remaining Series 3 preferred shares was reset for five years at 2.152 per cent per annum.

In March 2015, TransCanada completed a public offering of 10 million Series 11 cumulative redeemable first preferred shares at $25 per share resulting in gross proceeds of $250 million. The Series 11 preferred shareholders will have the right to convert their Series 11 preferred shares into Series 12 cumulative redeemable first preferred shares on November 30, 2020 and on November 30 of every fifth year thereafter. The holders of Series 12 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at an annual rate equal to the applicable 90-day Government of Canada treasury bill rate plus 2.96 per cent.

PREFERRED SHARE ISSUANCE AND CONVERSION

The following table summarizes the impact of the above transactions on the Series 3, 4 and 11 preferred shares at June 30, 2015:

(unaudited - millions of Canadian $, unless noted otherwise)	Number of shares issued and outstanding (thousands)	Current yield[1]	Annual dividend per share	Redemption price per share[2]	Redemption and conversion option date	Right to convert into
Cumulative first preferred shares						
Series 3	8,533	2.152%	0.538	$25.00	June 30, 2020	Series 4
Series 4	5,467	Floating[3]	Floating	$25.50	June 30, 2020	Series 3
Series 11	10,000	3.80%	0.95	$25.00	November 30, 2020	Series 12

1 Holders of the cumulative redeemable first preferred shares set out in this table are entitled to receive a quarterly fixed, cumulative, preferred dividend, as and when declared by the Board with the exception of Series 4 preferred shares. The holders of Series 4 preferred shares are entitled to receive quarterly, floating rate, cumulative, preferred dividends as and when declared by the Board.

2 TransCanada may, at its 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.

3 Commencing June 30, 2015, the floating quarterly dividend rate for the Series 4 preferred shares is 1.945 per cent and will reset every quarter going forward.

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

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

three months ended June 30, 2015 (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	**(135)**	**(2)**	**(137)**
Change in fair value of net investment hedges	**76**	**(18)**	**58**
Change in fair value of cash flow hedges	**(50)**	**14**	**(36)**
Reclassification to net income of gains and losses on cash flow hedges	**(17)**	**6**	**(11)**
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**10**	**—**	**10**
Other comprehensive income on equity investments	**5**	**(1)**	**4**
Other comprehensive loss	**(111)**	**(1)**	**(112)**

three months ended June 30, 2014 (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	(140)	(50)	(190)
Change in fair value of net investment hedges	107	(28)	79
Change in fair value of cash flow hedges	(9)	5	(4)
Reclassification to net income of gains and losses on cash flow hedges	4	(2)	2
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	7	(2)	5
Other comprehensive income on equity investments	1	1	2
Other comprehensive loss	(30)	(76)	(106)

six months ended June 30, 2015 (unaudited - millions of Canadian $)	**Before tax amount**	**Income tax recovery/ (expense)**	**Net of tax amount**
Foreign currency translation gains on net investments in foreign operations	**325**	**7**	**332**
Change in fair value of net investment hedges	**(283)**	**75**	**(208)**
Change in fair value of cash flow hedges	**(29)**	**8**	**(21)**
Reclassification to net income of gains and losses on cash flow hedges	**56**	**(23)**	**33**
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**20**	**(3)**	**17**
Other comprehensive income on equity investments	**9**	**(2)**	**7**
Other comprehensive income	**98**	**62**	**160**

six months ended June 30, 2014 (unaudited - millions of Canadian $)	Before tax amount	Income tax recovery/ (expense)	Net of tax amount
Foreign currency translation gains on net investments in foreign operations	51	(1)	50
Change in fair value of net investment hedges	(64)	16	(48)
Change in fair value of cash flow hedges	42	(15)	27
Reclassification to net income of gains and losses on cash flow hedges	(99)	39	(60)
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	13	(4)	9
Other comprehensive gain on equity investments	1	1	2
Other comprehensive loss	(56)	36	(20)

The changes in accumulated other comprehensive loss by component are as follows:

three months ended June 30, 2015 (unaudited - millions of Canadian $)	Currency translation adjustments	Cash flow hedges	Pension and OPEB plan adjustments	Equity investments	Total[1]
AOCI balance at April 1, 2015	**(463)**	**(69)**	**(274)**	**(305)**	**(1,111)**
Other comprehensive loss before reclassifications[2]	**(49)**	**(36)**	**—**	**—**	**(85)**
Amounts reclassified from accumulated other comprehensive loss	**—**	**(11)**	**10**	**4**	**3**
Net current period other comprehensive (loss)/ income	**(49)**	**(47)**	**10**	**4**	**(82)**
AOCI balance at June 30, 2015	**(512)**	**(116)**	**(264)**	**(301)**	**(1,193)**

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.
2 Other comprehensive income before reclassifications on currency translation adjustments is net of non-controlling interest loss of $30 million.

six months ended June 30, 2015 (unaudited - millions of Canadian $)	Currency translation adjustments	Cash flow hedges	Pension and OPEB plan adjustments	Equity Investments	Total[1]
AOCI balance at January 1, 2015	**(518)**	**(128)**	**(281)**	**(308)**	**(1,235)**
Other comprehensive income/(loss) before reclassifications[2]	**6**	**(21)**	**—**	**—**	**(15)**
Amounts reclassified from accumulated other comprehensive loss[3]	**—**	**33**	**17**	**7**	**57**
Net current period other comprehensive income	**6**	**12**	**17**	**7**	**42**
AOCI balance at June 30, 2015	**(512)**	**(116)**	**(264)**	**(301)**	**(1,193)**

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.
2 Other comprehensive income before reclassifications on currency translation adjustments is net of non-controlling interest gain of $118 million.
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 $78 million ($49 million, net of tax) at June 30, 2015. 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 accumulated other comprehensive loss are as follows:

	Amounts reclassified from accumulated other comprehensive loss[1]				Affected line item in the condensed consolidated statement of income
	three months ended June 30		six months ended June 30		
(unaudited - millions of Canadian $)	2015	2014	2015	2014	
Cash flow hedges					
Power and Natural Gas	**21**	(1)	**(48)**	107	Revenue (Energy)
Interest	**(4)**	(3)	**(8)**	(8)	Interest expense
	17	(4)	**(56)**	99	Total before tax
	(6)	2	**23**	(39)	Income tax expense
	11	(2)	**(33)**	60	Net of tax
Pension and OPEB plan adjustments					
Amortization of actuarial loss and past service cost	**(10)**	(7)	**(20)**	(13)	[2]
	—	2	**3**	4	Income tax expense
	(10)	(5)	**(17)**	(9)	Net of tax
Equity Investments					
Equity income	**(5)**	(1)	**(9)**	(1)	Income from equity investments
	1	(1)	**2**	(1)	Income tax expense
	(4)	(2)	**(7)**	(2)	Net of tax

1 All amounts in parentheses indicate expenses to the condensed consolidated statement of income.
2 These accumulated other comprehensive loss components are included in the computation of net benefit cost. Refer to Note 10 for additional detail.

10. Employee post-retirement benefits

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 June 30				six months ended June 30			
	Pension benefit plans		Other post-retirement benefit plans		Pension benefit plans		Other post-retirement benefit plans	
(unaudited - millions of Canadian $)	2015	2014	2015	2014	2015	2014	2015	2014
Service cost	**27**	21	**—**	—	**54**	43	**1**	1
Interest cost	**29**	28	**3**	3	**57**	56	**5**	5
Expected return on plan assets	**(39)**	(34)	**(1)**	(1)	**(77)**	(69)	**(1)**	(1)
Amortization of actuarial loss	**8**	6	**1**	—	**17**	11	**2**	1
Amortization of past service cost	**1**	1	**—**	—	**1**	1	**—**	—
Amortization of regulatory asset	**6**	4	**—**	—	**12**	9	**—**	—
Amortization of transitional obligation related to regulated business	**—**	—	**1**	1	**—**	—	**1**	1
Net benefit cost recognized	**32**	26	**4**	3	**64**	51	**8**	7

11. Risk management and financial instruments

RISK MANAGEMENT OVERVIEW

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

COUNTERPARTY CREDIT RISK

TransCanada's maximum counterparty credit exposure with respect to financial instruments at June 30, 2015, without taking into account security held, consisted of accounts receivable, portfolio investments recorded at fair value, the fair value of derivative assets and notes, loans and advances receivable. At June 30, 2015, 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 $222 million (US$178 million) and $258 million (US$222 million) at June 30, 2015 and December 31, 2014, respectively. 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)	June 30, 2015	December 31, 2014
Carrying value	**19,500 (US 15,600)**	17,000 (US 14,700)
Fair value	**21,400 (US 17,200)**	19,000 (US 16,400)

Derivatives designated as a net investment hedge

	June 30, 2015		December 31, 2014	
(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 2015 to 2019)[2]	**(560)**	**US 2,500**	(431)	US 2,900
U.S. dollar foreign exchange forward contracts				
(maturing 2015)	**(39)**	**US 1,572**	(28)	US 1,400
	(599)	**US 4,072**	(459)	US 4,300

1 Fair values equal carrying values.
2 Net income in the three and six months ended June 30, 2015 included net realized gains of $2 million and $5 million, respectively, (2014 - gains of $5 million and $11 million, respectively) related to the interest component of cross-currency swaps which is offset in interest expense.

Balance sheet presentation of net investment hedges

The balance sheet classification of the fair value of derivatives used to hedge the Company's net investment in foreign operations is as follows:

(unaudited - millions of Canadian $)	June 30, 2015	December 31, 2014
Other current assets	**23**	5
Intangible and other assets	**1**	1
Accounts payable and other	**(269)**	(155)
Other long-term liabilities	**(354)**	(310)
	(599)	(459)

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 with carrying amounts that approximate fair value, that would be classified in Level II of the fair value hierarchy:

	June 30, 2015		December 31, 2014	
(unaudited - millions of Canadian $)	Carrying amount	Fair value	Carrying amount	Fair value
Notes receivable and other[1]	**192**	**237**	213	263
Current and long-term debt[2,3]	**(26,698)**	**(30,556)**	(24,757)	(28,713)
Junior subordinated notes	**(2,182)**	**(2,124)**	(1,160)	(1,157)
	(28,688)	**(32,443)**	(25,704)	(29,607)

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$750 million (December 31, 2014 - US$400 million) that is attributed to hedged risk and recorded at fair value.
3 Consolidated net income for the three and six months ended June 30, 2015 included unrealized gains of $3 million and nil, respectively, (2014 - gains of $1 million and losses of $5 million, respectively) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$750 million of long-term debt at June 30, 2015 (December 31, 2014 - US$400 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Available for sale assets summary

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

(unaudited - millions of Canadian $)	June 30, 2015		December 31, 2014	
	LMCI restricted investments	Other restricted investments[2]	LMCI restricted investments	Other restricted investments[2]
Fair Values[1]				
Fixed income securities (maturing within 5 years)	**—**	**74**	—	75
Fixed income securities (maturing after 10 years)	**117**	**—**	—	—
	117	**74**	—	75

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.

(unaudited - millions of Canadian $)	June 30, 2015		June 30, 2014	
	LMCI restricted investments[1]	Other restricted investments[2]	LMCI restricted investments[1]	Other restricted investments[2]
Net unrealized losses in the period				
three months ended	**(3)**	**—**	—	—
six months ended	**(3)**	**—**	—	—

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

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 power and natural gas 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. 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 is as follows:

(unaudited - millions of Canadian $)	June 30, 2015	December 31, 2014
Other current assets	**369**	409
Intangible and other assets	**134**	93
Accounts payable and other	**(775)**	(749)
Other long-term liabilities	**(531)**	(411)
	(803)	(658)

2015 derivative instruments summary

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

(unaudited - millions of Canadian $, unless noted otherwise)	Power	Natural gas	Foreign exchange	Interest
Derivative instruments held for trading[1]				
Fair values[2,3]				
Assets	**$381**	**$45**	**$2**	**$5**
Liabilities	**($416)**	**($86)**	**($32)**	**($5)**
Notional values[3]				
Volumes[4]				
Purchases	**67,765**	**98**	**—**	**—**
Sales	**55,016**	**57**	**—**	**—**
U.S. dollars	**—**	**—**	**US 1,352**	**US 100**
Net unrealized gains/(losses) in the period[5]				
three months ended June 30, 2015	**$27**	**($4)**	**$30**	**$—**
six months ended June 30, 2015	**$1**	**($4)**	**$1**	**$—**
Net realized (losses)/gains in the period[5]				
three months ended June 30, 2015	**($23)**	**($10)**	**($10)**	**$—**
six months ended June 30, 2015	**($33)**	**$1**	**($53)**	**$—**
Maturity dates[3]	**2015-2020**	**2015-2020**	**2015-2016**	**2015-2016**
Derivative instruments in hedging relationships[6,7]				
Fair values[2,3]				
Assets	**$42**	**$—**	**$—**	**$4**
Liabilities	**($141)**	**$—**	**$—**	**($3)**
Notional values[3]				
Volumes[4]				
Purchases	**13,886**	**—**	**—**	**—**
Sales	**4,120**	**—**	**—**	**—**
U.S. dollars	**—**	**—**	**—**	**US 900**
Net realized (losses)/gains in the period[5]				
three months ended June 30, 2015	**($113)**	**$—**	**$—**	**$2**
six months ended June 30, 2015	**($97)**	**$—**	**$—**	**$4**
Maturity dates[3]	**2015-2020**	**—**	**—**	**2015-2019**

1 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.

2 Fair values equal carrying values.

3 As at June 30, 2015.

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

5 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell power and natural gas are included net in energy 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 expense, respectively. The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to energy revenues, interest expense and interest income and other expense, as appropriate, as the original hedged item settles.

6 All hedging relationships are designated as cash flow hedges except for interest rate derivative instruments designated as fair value hedges with a fair value of $3 million and a notional amount of US$750 million as at June 30, 2015. For the three and six months ended June 30, 2015, net realized gains on fair value hedges were $2 million and $4 million, respectively, and were included in interest expense. For the three and six months ended June 30, 2015, the Company did not record any amounts in net income related to ineffectiveness for fair value hedges.

7 For the three and six months ended June 30, 2015, there were no gains or losses included in net income for discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

2014 derivative instruments summary

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

(unaudited - millions of Canadian $, unless noted otherwise)	Power	Natural gas	Foreign exchange	Interest
Derivative instruments held for trading[1]				
Fair values[2,3]				
Assets	$362	$69	$1	$4
Liabilities	($391)	($103)	($32)	($4)
Notional values[3]				
Volumes[4]				
Purchases	42,097	60	—	—
Sales	35,452	38	—	—
U.S. dollars	—	—	US 1,374	US 100
Net unrealized gains/(losses) in the period[5]				
three months ended June 30, 2014	$6	($14)	$25	$—
six months ended June 30, 2014	$15	($21)	$23	$—
Net realized (losses)/gains in the period[5]				
three months ended June 30, 2014	($3)	($4)	($1)	$—
six months ended June 30, 2014	($31)	$46	($18)	$—
Maturity dates[3]	2015-2019	2015-2020	2015	2015-2016
Derivative instruments in hedging relationships [6,7]				
Fair values[2,3]				
Assets	$57	$—	$—	$3
Liabilities	($163)	$—	$—	($2)
Notional values[3]				
Volumes[4]				
Purchases	11,120	—	—	—
Sales	3,977	—	—	—
U.S. dollars	—	—	—	US 550
Net realized (losses)/gains in the period[5]				
three months ended June 30, 2014	($4)	$—	$—	$1
six months ended June 30, 2014	$188	$—	$—	$2
Maturity dates[3]	2015-2019	—	—	2015-2018

1. 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.
2. Fair values equal carrying values.
3. As at December 31, 2014.
4. Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.
5. Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell power and natural gas are included net in energy 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 expense, respectively. The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to energy revenues, interest expense and interest income and other expense, as appropriate, as the original hedged item settles.
6. All hedging relationships are designated as cash flow hedges except for interest rate derivative instruments designated as fair value hedges with a fair value of $3 million and a notional amount of US$400 million as at December 31, 2014. Net realized gains on fair value hedges for the three and six months ended June 30, 2014 were $2 million and $3 million, respectively, and were included in interest expense. For the three and six months ended June 30, 2014, the Company did not record any amounts in net income related to ineffectiveness for fair value hedges.
7. For the three and six months ended June 30, 2014, there were no gains or losses included in net income for discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

Derivatives in cash flow hedging relationships

The components of OCI (Note 9) related to derivatives in cash flow hedging relationships are as follows:

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $, pre-tax)	**2015**	2014	**2015**	2014
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]				
Power	**(50)**	(7)	**(29)**	34
Natural gas	**—**	(1)	**—**	(1)
Foreign exchange	**—**	—	**—**	10
Interest	**—**	(1)	**—**	(1)
	(50)	(9)	**(29)**	42
Reclassification of (losses)/gains on derivative instruments from AOCI to net income (effective portion)[1]				
Power[2]	**(21)**	(1)	**48**	(109)
Natural gas[2]	**—**	2	**—**	2
Interest[3]	**4**	3	**8**	8
	(17)	4	**56**	(99)
Gains/(losses) on derivative instruments recognized in net income (ineffective portion)				
Power	**56**	3	**(7)**	(10)
	56	3	**(7)**	(10)

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI.
2 Reported within energy revenues on the condensed consolidated statement of income.
3 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 June 30, 2015 (unaudited - millions of Canadian $)	Gross derivative instruments presented on the balance sheet	Amounts available for offset[1]	Net amounts
Derivative - Asset			
Power	**423**	**(351)**	**72**
Natural gas	**45**	**(35)**	**10**
Foreign exchange	**26**	**(26)**	**—**
Interest	**9**	**(1)**	**8**
Total	**503**	**(413)**	**90**
Derivative - Liability			
Power	**(557)**	**351**	**(206)**
Natural gas	**(86)**	**35**	**(51)**
Foreign exchange	**(655)**	**26**	**(629)**
Interest	**(8)**	**1**	**(7)**
Total	**(1,306)**	**413**	**(893)**

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, 2014:

at December 31, 2014 (unaudited - millions of Canadian $)	**Gross derivative instruments presented on the balance sheet**	**Amounts available for offset**[1]	**Net amounts**
Derivative - Asset			
Power	419	(330)	89
Natural gas	69	(57)	12
Foreign exchange	7	(7)	—
Interest	7	(1)	6
Total	502	(395)	107
Derivative - Liability			
Power	(554)	330	(224)
Natural gas	(103)	57	(46)
Foreign exchange	(497)	7	(490)
Interest	(6)	1	(5)
Total	(1,160)	395	(765)

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

With respect to all financial arrangements, including the derivative instruments presented above as at June 30, 2015, the Company had provided cash collateral of $517 million (December 31, 2014 - $459 million) and letters of credit of $40 million (December 31, 2014 - $26 million) to its counterparties. The Company held nil (December 31, 2014 - $1 million) in cash collateral and $4 million (December 31, 2014 - $1 million) in letters of credit from counterparties on asset exposures at June 30, 2015.

Credit risk related contingent features of derivative instruments

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

Based on contracts in place and market prices at June 30, 2015, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $4 million (December 31, 2014 - $15 million), for which the Company had provided collateral in the normal course of business of nil (December 31, 2014 - nil). If the credit-risk-related contingent features in these agreements were triggered on June 30, 2015, the Company would have been required to provide additional collateral of $4 million (December 31, 2014 - $15 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 power and natural gas 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 derivatives fair value. This category includes long-dated commodity transactions in certain markets where liquidity is low and inputs may include long-term broker quotes. Long-term electricity prices may also be estimated using a third-party modeling tool which takes into account physical operating characteristics of generation facilities in the markets in which the Company operates. Model inputs include market fundamentals such as fuel prices, power supply additions and retirements, power demand, seasonal hydro conditions and transmission constraints. Long-term North American natural gas prices might be estimated on a view of future natural gas supply and demand, as well as exploration and development costs. Significant decreases in fuel prices or demand for electricity or natural gas, or increases in the supply of electricity or natural gas, small number of transactions in markets with lower liquidity are expected to or may result in a lower fair value measurement of contracts included in Level III. 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, are categorized as follows:

at June 30, 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:				
Power commodity contracts	**—**	**419**	**4**	**423**
Natural gas commodity contracts	**26**	**9**	**10**	**45**
Foreign exchange contracts	**—**	**26**	**—**	**26**
Interest rate contracts	**—**	**9**	**—**	**9**
Derivative instrument liabilities:				
Power commodity contracts	**—**	**(554)**	**(3)**	**(557)**
Natural gas commodity contracts	**(70)**	**(16)**	**—**	**(86)**
Foreign exchange contracts	**—**	**(655)**	**—**	**(655)**
Interest rate contracts	**—**	**(8)**	**—**	**(8)**
	(44)	**(770)**	**11**	**(803)**

1 There were no transfers from Level I to Level II or from Level II to Level III for the six months ended June 30, 2015.

The fair value of the Company's assets and liabilities measured on a recurring basis, including both current and non-current portions for 2014, are categorized as follows:

at December 31, 2014 (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:				
Power commodity contracts	—	417	2	419
Natural gas commodity contracts	40	24	5	69
Foreign exchange contracts	—	7	—	7
Interest rate contracts	—	7	—	7
Derivative instrument liabilities:				
Power commodity contracts	—	(551)	(3)	(554)
Natural gas commodity contracts	(86)	(17)	—	(103)
Foreign exchange contracts	—	(497)	—	(497)
Interest rate contracts	—	(6)	—	(6)
	(46)	(616)	4	(658)

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2014.

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

	three months ended June 30		**six months ended June 30**	
(unaudited - millions of Canadian $, pre-tax)	**2015**	**2014**	**2015**	**2014**
Balance at beginning of period	**2**	1	**4**	1
Transfers into Level III	**3**	—	**3**	—
Total gains/(losses) included in net income	**8**	(2)	**5**	(2)
Total losses included in OCI	**(2)**	—	**(1)**	—
Balance at end of period[1]	**11**	(1)	**11**	(1)

1 For the three and six months ended June 30, 2015, energy revenues include unrealized gains attributed to derivatives in the Level III category that were still held at June 30, 2015 of $11 million and $8 million, respectively (2014 - losses of $2 million and $2 million, respectively).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $1 million increase or decrease, respectively, in the fair value of outstanding derivative instruments included in Level III as at June 30, 2015.

12. Sale of GTN Pipeline to TC PipeLines, LP

On April 1, 2015, TransCanada completed the sale of its remaining 30 per cent interest in Gas Transmission Northwest (GTN) to TC PipeLines, LP for an aggregate purchase price of US$446 million plus a purchase price adjustment of US$11 million. The US$457 million sale was comprised of US$264 million in cash, the assumption of US$98 million in proportional GTN debt and US$95 million of new Class B units of TC PipeLines, LP.

13. Contingencies 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.

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 B related to a lease agreement and contractor and supplier services. In addition, TransCanada and BPC have each severally guaranteed one-half of certain contingent financial obligations of Bruce A related to a sublease agreement and certain other financial obligations. 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, PPA payments 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 June 30, 2015		at December 31, 2014	
(unaudited - millions of Canadian $)	Term	Potential exposure[1]	Carrying value	Potential exposure[1]	Carrying value
Bruce Power	ranging to 2019[2]	**573**	**5**	634	6
Other jointly owned entities	ranging to 2040	**71**	**14**	104	14
		644	**19**	738	20

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

14. Subsequent event

On July 17, 2015, TCPL completed an offering of $750 million, 3.3 per cent Medium Term Notes due July 17, 2025.