QuarterlyReport to Shareholders

TransCanada Reports Solid First Quarter 2015 Financial Results

CALGARY, Alberta – **May 1, 2015** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada) today announced net income attributable to common shares for first quarter 2015 of $387 million or $0.55 per share compared to $412 million or $0.58 per share for the same period in 2014. Comparable earnings for first quarter 2015 were $465 million or $0.66 per share compared to $422 million or $0.60 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 June 30, 2015, equivalent to $2.08 per common share on an annualized basis.

"Solid performance in the first quarter from each of our core business segments contributed to an increase in comparable earnings and funds generated from operations of ten and five per cent, respectively, compared to the same period last year," said Russ Girling, TransCanada's president and chief executive officer. "Strong performance from our Keystone System, Eastern Canadian Power and U.S. Power segments helped to offset depressed power prices in Western Power and clearly demonstrates the strength of our diverse portfolio of critical energy infrastructure assets. Looking forward, we remain well positioned to grow earnings, cash flow and dividends over the next three years as we work to bring $12 billion of small to medium-sized growth projects into service."

We also continue to advance a number of other growth initiatives, including $34 billion of commercially secured projects, which would extend and possibly augment the future growth rate in earnings, cash flow and dividends through the end of the decade. With our high-quality asset base and a strong balance sheet, 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)

- First quarter financial results
  - Net income attributable to common shares of $387 million or $0.55 per share
  - Comparable earnings of $465 million or $0.66 per share
  - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.5 billion
  - Funds generated from operations of $1.2 billion
- Declared a quarterly dividend of $0.52 per common share for the quarter ending June 30, 2015
- Commenced construction on the $1 billion Napanee Power Project
- The National Energy Board (NEB) issued a report recommending the federal government approve 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$446 million on April 1, 2015
- Altered the project scope for the Energy East Pipeline with the decision not to build a marine and associated tank terminal at Cacouna, Québec in April 2015
- Completed over $2 billion of financing with the issuance of senior notes and preferred shares

Net income attributable to common shares decreased by $25 million to $387 million or $0.55 per share for the three months ended March 31, 2015 compared to the same period in 2014. Both periods included unrealized gains and losses from changes in risk management activities which are excluded from comparable earnings.

Comparable earnings for first quarter 2015 were $465 million or $0.66 per share compared to $422 million or $0.60 per share for the same period in 2014. Higher earnings from Keystone, Mexican Pipelines, U.S. Power and Eastern Power were offset by lower contributions from Western Power, the Canadian Mainline and Natural Gas Storage.

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

Natural Gas Pipelines:

- *NGTL System Expansions:* The NGTL System has approximately $6.7 billion of new supply and demand facilities currently under development. In first quarter 2015, we continued to advance several of these capital expansion projects by filing their regulatory applications with the NEB and plan to file additional facilities applications for this program throughout 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.

  On April 15, 2015, the 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 British Columbia (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 liquefied natural gas (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 Prince Rupert Gas Transmission (PRGT) project to provide natural gas supply to the proposed Pacific NorthWest (PNW) LNG liquefaction and export facility near Prince Rupert, B.C. Subject to certain conditions, including a positive final investment decision (FID) on the proposed PNW LNG project, NGTL expects to have the Aitken Creek Section in service in 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. NGTL will engage its shippers to determine an appropriate approach that best meets market requirements.

- *PRGT:* We anticipate decisions in second quarter 2015 from the B.C. Oil and Gas Commission (BC OGC) on the permits required to build and operate the PRGT pipeline project.

  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. The project is subject to regulatory approvals and a positive FID.

- *Coastal GasLink:* We also anticipate decisions in second quarter 2015 from the BC OGC on the permits required to build and operate Coastal GasLink.

  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$446 million sale was comprised of US$253 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 and enhance the size and diversity of the Partnership's asset base, positioning it with visible, high quality future growth.

At March 31, 2015, we held a 28.3 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 potential reclassification of beluga whales as an endangered species. We are currently evaluating other options and discussing those options with our shippers. Amendments to the project are expected to be submitted to the NEB in fourth quarter 2015. The alteration to the project scope and further refinement of the project schedule is expected to result in an in-service date of 2020.

  Binding long term contracts of approximately one million barrels per day (Bbl/d) for the 1.1 million Bbl/d pipeline have been secured. The project is estimated to cost approximately $12 billion, excluding the transfer value of Canadian Mainline natural gas assets.

- *Keystone XL:* In January 2015, the U.S. 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 have been submitted to the DOS.

  On February 12, 2015, Nebraska county courts granted temporary injunctions that were negotiated between TransCanada 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 Keystone authority to construct 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.

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

  The estimated capital cost for Keystone XL is expected to be approximately US$8.0 billion. As of March 31, 2015, we have invested US$2.4 billion in the project and have also capitalized interest in the amount of US$0.4 billion.

- *Houston Lateral and Tank Terminal:* Construction continues on the 77 km (48 mile) Houston Lateral pipeline and Tank Terminal which will extend the Keystone Pipeline System to refineries in Houston, Texas. 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, TransCanada and 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 the 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.

Energy:

- *Napanee Project:* In January 2015, we began construction activities on the 900 megawatt (MW) natural gas-fired power plant at Ontario Power Generation's Lennox site in eastern Ontario in the town of Greater Napanee. We expect to invest approximately $1 billion in the Napanee facility during construction and commercial operations are expected to begin in late 2017 or early 2018. Production from the facility is fully contracted for 20 years with the Independent Electricity System Operator.

Corporate:

- Our Board of Directors declared a quarterly dividend of $0.52 per share for the quarter ending June 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 January 2015, we issued US$500 million of three-year fixed rate senior notes bearing interest at 1.875 per cent, and US$250 million of three-year LIBOR-based floating rate senior notes, bearing interest at an initial rate of 1.045 per cent, both maturing on January 12, 2018.

  In March 2015, we completed a public offering of 10 million Series 11 Cumulative Redeemable First Preferred Shares. The Series 11 shares were issued at a price of $25 per share, resulting in gross proceeds of $250 million. The initial dividend rate is fixed to but excluding November 30, 2020 at an annual rate of $0.95 per share payable quarterly.

  In March 2015, we issued US$750 million of 30-year senior notes bearing interest at 4.60 per cent that mature on March 31, 2045. These notes are redeemable at par on March 31, 2020 and annually thereafter.

  The net proceeds of these offerings are intended to 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.

  In March 2015, TC PipeLines, LP issued US$350 million of ten-year senior notes bearing interest at 4.375 per cent that mature on March 31, 2025. The net proceeds from this offering were used to finance the acquisition of the 30 per cent interest in GTN and to repay short-term indebtedness.

Teleconference – Audio and Slide Presentation:

We will hold a teleconference and webcast on Friday, May 1, 2015 to discuss our first 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 1 p.m. (MT) / 3 p.m. (ET).

Analysts, members of the media and other interested parties are invited to participate by calling 800.396.7098 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 (ET) on May 8, 2015. Please call 800.408.3053 or 905.694.9451 and enter pass code 8512000.

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 April 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 April 30, 2015.

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Quarterly report to shareholders

First quarter 2015

Financial highlights

	three months ended March 31	
(unaudited - millions of $, except per share amounts)	**2015**	**2014**
Income		
Revenue	**2,874**	2,884
Net income attributable to common shares	**387**	412
per common share - basic and diluted	**$0.55**	$0.58
Comparable EBITDA[1]	**1,531**	1,396
Comparable earnings[1]	**465**	422
per common share[1]	**$0.66**	$0.60
Operating cash flow		
Funds generated from operations[1]	**1,153**	1,102
Increase in operating working capital	**(393)**	(123)
Net cash provided by operations	**760**	979
Investing activities		
Capital expenditures	**806**	744
Capital projects under development	**201**	104
Equity investments	**93**	89
Dividends paid		
Per common share	**$0.52**	$0.48
Basic common shares outstanding (millions)		
Average for the period	**709**	708
End of period	**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

April 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 months ended March 31, 2015, and should be read with the accompanying unaudited condensed consolidated financial statements for the three months ended March 31, 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, which have been prepared in accordance with U.S. GAAP.

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 April 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, unless we are required to by law.

FOR MORE INFORMATION

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

NON-GAAP MEASURES

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 Non-GAAP Reconciliation 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
- gains or losses on sales of assets
- legal, contractual and bankruptcy settlements
- impact of regulatory or arbitration decisions relating to prior year earnings
- 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 - first quarter 2015

(unaudited - millions of $, except per share amounts)	three months ended March 31 2015	2014
Natural Gas Pipelines	**595**	586
Liquids Pipelines	**246**	192
Energy	**214**	257
Corporate	**(47)**	(43)
Total segmented earnings	**1,008**	992
Interest expense	**(318)**	(274)
Interest income and other expense	**(14)**	(8)
Income before income taxes	**676**	710
Income tax expense	**(207)**	(221)
Net income	**469**	489
Net income attributable to non-controlling interests	**(59)**	(54)
Net income attributable to controlling interests	**410**	435
Preferred share dividends	**(23)**	(23)
Net income attributable to common shares	**387**	412
Net income per common share - basic and diluted	**$0.55**	$0.58

Net income attributable to common shares decreased by $25 million for the three months ended March 31, 2015 compared to the same period in 2014. Net income in both periods included unrealized gains and losses from changes in risk management activities and we exclude these unrealized gains and losses to arrive at comparable earnings. For the three months ended March 31, 2015, comparable earnings increased by $43 million compared to the same period 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 March 31 2015	2014
Net income attributable to common shares	**387**	412
Specific items (net of tax):		
Risk management activities[1]	**78**	10
Comparable earnings	**465**	422
Net income per common share	**$0.55**	$0.58
Specific items (net of tax):		
Risk management activities[1]	**0.11**	0.02
Comparable earnings per share	**$0.66**	$0.60

1

Risk management activities (unaudited - millions of $)	three months ended March 31 2015	2014
Canadian Power	**(22)**	—
U.S. Power	**(68)**	(2)
Natural Gas Storage	**1**	(9)
Foreign exchange	**(29)**	(2)
Income tax attributable to risk management activities	**40**	3
Total losses from risk management activities	**(78)**	(10)

Comparable earnings increased by $43 million for the three months ended March 31, 2015 compared to the same period in 2014. This was primarily the net effect of:

- incremental earnings from the Gulf Coast extension which was placed in service in January 2014 and higher volumes on the Keystone Pipeline System
- higher earnings from U.S. Power mainly due to timing of earnings recognized on certain contracts in our power marketing business
- higher earnings from the Tamazunchale Extension which was placed in service in 2014
- 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
- lower earnings from Western Power as a result of lower realized power prices
- lower earnings from Natural Gas Storage due to lower realized natural gas price spreads
- higher interest expense from debt issuances, higher foreign exchange on interest related to U.S. dollar-denominated debt and lower capitalized interest on projects placed in service.

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 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 March 31, 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 0.4
Topolobampo	Natural Gas Pipelines	2016	US 1.0	US 0.7
Mazatlan	Natural Gas Pipelines	2016	US 0.4	US 0.2
Grand Rapids[1]	Liquids Pipelines	2016-2017	1.5	0.3
Heartland and TC Terminals	Liquids Pipelines	2017	0.9	0.1
Northern Courier	Liquids Pipelines	2017	1.0	0.3
Canadian Mainline - Other	Natural Gas Pipelines	2015-2016	0.4	—
NGTL System - North Montney	Natural Gas Pipelines	2016-2017	1.7	0.1
- 2016/17 Facilities	Natural Gas Pipelines	2016-2018	2.7	0.1
- Other	Natural Gas Pipelines	2015-2016	0.4	—
Napanee	Energy	2017 or 2018	1.0	0.1
			11.6	2.3
Large-scale, medium and longer-term				
Upland	Liquids Pipelines	2020	US 0.6	US —
Keystone projects				
Keystone XL[2]	Liquids Pipelines	[3]	US 8.0	US 2.4
Keystone Hardisty Terminal	Liquids Pipelines	[3]	0.3	0.2
Energy East projects				
Energy East[4]	Liquids Pipelines	2020	12.0	0.6
Eastern Mainline	Natural Gas Pipelines	2017	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	2019+	5.0	0.3
NGTL System - Merrick	Natural Gas Pipelines	2020	1.9	—
			34.1	3.8
			45.7	6.1

1 Represents our 50 per cent share.
2 Estimated project cost dependent on the timing of the Presidential permit.
3 Approximately two years from the date the Keystone XL permit is received.
4 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 March 31	
(unaudited - millions of $)	**2015**	**2014**
Comparable EBITDA	**874**	848
Comparable depreciation and amortization[1]	**(279)**	(262)
Comparable EBIT	**595**	586
Specific items[2]	**—**	—
Segmented earnings	**595**	586

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

Natural Gas Pipelines segmented earnings increased by $9 million for the three months ended March 31, 2015 compared to the same period in 2014 and are equivalent to comparable EBIT which, along with comparable EBITDA, are discussed below.

	three months ended March 31	
(unaudited - millions of $)	**2015**	**2014**
Canadian Pipelines		
Canadian Mainline	**266**	315
NGTL System	**222**	219
Foothills	**27**	27
Other Canadian pipelines[1]	**7**	5
Canadian Pipelines - comparable EBITDA	**522**	566
Comparable depreciation and amortization	**(209)**	(203)
Canadian Pipelines - comparable EBIT	**313**	363
U.S. and International Pipelines (US$)		
ANR	**88**	78
TC PipeLines, LP[1,2]	**26**	26
Great Lakes[3]	**20**	19
Other U.S. pipelines (Bison[4], Iroquois[1], GTN[5], Portland[6])	**41**	45
Mexico (Guadalajara, Tamazunchale)	**47**	25
International and other[1,7]	**2**	(1)
Non-controlling interests[8]	**74**	73
U.S. and International Pipelines - comparable EBITDA	**298**	265
Comparable depreciation and amortization	**(57)**	(54)
U.S. and International Pipelines - comparable EBIT	**241**	211
Foreign exchange impact	**59**	21
U.S. and International Pipelines - comparable EBIT (Cdn$)	**300**	232
Business Development comparable EBITDA and EBIT	**(18)**	(9)
Natural Gas Pipelines - comparable EBIT	**595**	586

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, will decrease our ownership interest in TC PipeLines, LP going forward. On October 1, 2014, we sold our remaining 30 per cent interest in Bison 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. On April 1, 2015, we sold our remaining 30 per cent direct interest in GTN to TC PipeLines, LP.

	Ownership percentage as of	
	October 1, 2014	**January 1, 2014**
TC PipeLines, LP	28.3	28.9
Effective ownership through TC PipeLines, LP:		
Bison	28.3	20.2
GTN	19.8	20.2
Great Lakes	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 July 1, 2013, represents our 30 per cent direct ownership interest in GTN. On April 1, 2015, we sold our remaining direct interest in GTN to TC PipeLines, LP.
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 March 31	
(unaudited - millions of $)	**2015**	**2014**
Canadian Mainline	**47**	66
NGTL System	**64**	63
Foothills	**4**	4

Net income for the Canadian Mainline decreased by $19 million for the three months ended March 31, 2015 compared to the same period in 2014. In 2015, the Canadian Mainline began operating under the 2015 - 2030 Tolls and Tariff Application approved by the NEB in November 2014. The decrease in net income was due to a lower ROE of 10.10 per cent in 2015 compared to 11.50 per cent in 2014 on deemed common equity of 40 per cent as well as lower incentive earnings and a lower average investment base in 2015.

Net income for the NGTL System increased by $1 million for the three months ended March 31, 2015 compared to the same period in 2014 mainly due to a higher average investment base.

U.S. AND INTERNATIONAL PIPELINES

Earnings for our U.S. natural gas pipelines operations are generally affected by contracted volume levels, volumes delivered and the rates charged as well as by the cost of providing services, including OM&A and property taxes. ANR is also affected by the contracting and pricing of its storage capacity and incidental commodity sales.

Comparable EBITDA for U.S. and International Pipelines increased by US$33 million for the three months ended March 31, 2015 compared to the same period in 2014. This was the net effect of:

- higher earnings from the Tamazunchale Extension which was placed in service in 2014
- ANR's settlement with a producer for damages to ANR's pipeline, partially offset by lower storage revenue from ANR.

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 $17 million for the three months ended March 31, 2015 compared to the same period 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 $9 million for the three months ended March 31, 2015 compared to the same period in 2014 mainly due to increased business development activity.

OPERATING STATISTICS - WHOLLY OWNED PIPELINES

three months ended March 31	**Canadian Mainline**[1]		**NGTL System**[2]		**ANR**[3]	
(unaudited)	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**
Average investment base (millions of $)	**5,018**	5,706	**6,419**	6,137	**n/a**	n/a
Delivery volumes (Bcf)						
Total	**529**	528	**1,058**	1,131	**509**	525
Average per day	**5.9**	5.9	**11.8**	12.6	**5.7**	5.8

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 three months ended March 31, 2015 were 302 Bcf (2014 – 357 Bcf). Average per day was 3.4 Bcf (2014 – 4.0 Bcf).

2 Field receipt volumes for the NGTL System for the three months ended March 31, 2015 were 1,009 Bcf (2014 – 933 Bcf). Average per day was 11.2 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).

	three months ended March 31	
(unaudited - millions of $)	**2015**	**2014**
Comparable EBITDA	**309**	241
Comparable depreciation and amortization[1]	**(63)**	(49)
Comparable EBIT	**246**	192
Specific items[2]	**—**	—
Segmented earnings	**246**	192

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

Liquids Pipelines segmented earnings increased by $54 million for the three months ended March 31, 2015 compared to the same period in 2014 and are equivalent to comparable EBIT, which, along with comparable EBITDA, are discussed below.

	three months ended March 31	
(unaudited - millions of $)	**2015**	**2014**
Keystone Pipeline System	**314**	248
Liquids Pipelines Business Development	**(5)**	(7)
Liquids Pipelines - comparable EBITDA	**309**	241
Comparable depreciation and amortization	**(63)**	(49)
Liquids Pipelines - comparable EBIT	**246**	192

Comparable EBIT denominated as follows:		
Canadian dollars	**61**	49
U.S. dollars	**149**	129
Foreign exchange impact	**36**	14
	246	192

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 $66 million for the three months ended March 31, 2015 compared to the same period in 2014. This increase was primarily due to:

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

COMPARABLE DEPRECIATION AND AMORTIZATION

Comparable depreciation and amortization increased by $14 million for the three months ended March 31, 2015 compared to the same period 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).

	three months ended March 31	
(unaudited - millions of $)	**2015**	2014
Comparable EBITDA	**388**	345
Comparable depreciation and amortization[1]	**(85)**	(77)
Comparable EBIT	**303**	268
Specific items (pre-tax):		
Risk management activities	**(89)**	(11)
Segmented earnings	**214**	257

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

Energy segmented earnings decreased by $43 million for the three months ended March 31, 2015 compared to the same period in 2014 and included the following unrealized gains and losses from changes in the fair value of derivatives:

Risk management activities	**three months ended March 31**	
(unaudited - millions of $, pre-tax)	**2015**	**2014**
Canadian Power	**(22)**	—
U.S. Power	**(68)**	(2)
Natural Gas Storage	**1**	(9)
Total losses from risk management activities	**(89)**	(11)

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 losses in U.S. Power for first quarter 2015 are due to the timing of recognizing certain earnings from our power marketing business. The majority of these unrealized losses will be realized in second quarter 2015. Please see the U.S. Power section of this MD&A for further discussion on these timing differences.

Canadian Power losses from risk management activities are a result of declining Alberta power prices, as discussed in the Western Power section.

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

	three months ended March 31	
(unaudited - millions of $)	2015	2014
Canadian Power		
Western Power	**15**	72
Eastern Power[1]	**131**	93
Bruce Power	**79**	64
Canadian Power - comparable EBITDA[2]	**225**	229
Comparable depreciation and amortization	**(48)**	(44)
Canadian Power - comparable EBIT[2]	**177**	185
U.S. Power (US$)		
U.S. Power - comparable EBITDA	**133**	86
Comparable depreciation and amortization	**(27)**	(27)
U.S. Power - comparable EBIT	**106**	59
Foreign exchange impact	**24**	5
U.S. Power - comparable EBIT (Cdn$)	**130**	64
Natural Gas Storage and other - comparable EBITDA	**3**	27
Comparable depreciation and amortization	**(3)**	(3)
Natural Gas Storage and other - comparable EBIT	**—**	24
Business Development comparable EBITDA and EBIT	**(4)**	(5)
Energy - comparable EBIT[2]	**303**	268

1 Includes three solar facilities acquired in September 2014 and one solar facility acquired in December 2014.
2 Includes our share of equity income from our investments in ASTC Power Partnership, Portlands Energy and Bruce Power.

Comparable EBITDA for Energy increased by $43 million for the three months ended March 31, 2015 compared to the same period in 2014 due to the net effect of:

- higher 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
- 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 higher volumes as a result of fewer outage days
- lower earnings from Western Power as a result of lower realized power prices
- 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 March 31 2015	2014
Revenue[1]		
Western Power	**108**	181
Eastern Power[2]	**125**	142
Other[3]	**45**	51
	278	374
Income from equity investments[4]	**5**	20
Commodity purchases resold	**(90)**	(101)
Plant operating costs and other	**(69)**	(128)
Exclude risk management activities[1]	**22**	—
Comparable EBITDA	**146**	165
Comparable depreciation and amortization	**(48)**	(44)
Comparable EBIT	**98**	121

Breakdown of comparable EBITDA		
Western Power	**15**	72
Eastern Power	**131**	93
Comparable EBITDA	**146**	165

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 three solar facilities acquired in September 2014 and one solar facility acquired in December 2014.
3 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.
4 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 March 31 2015	2014
Sales volumes (GWh)		
Supply		
Generation		
Western Power	**637**	609
Eastern Power[1]	**1,323**	1,277
Purchased		
Sundance A & B and Sheerness PPAs[2]	**2,388**	2,800
Other purchases	**8**	5
	4,356	4,691
Sales		
Contracted		
Western Power	**1,645**	2,461
Eastern Power[1]	**1,323**	1,277
Spot		
Western Power	**1,388**	953
	4,356	4,691
Plant availability[3]		
Western Power[4]	**97%**	96%
Eastern Power[1,5]	**98%**	98%

1 Includes three solar facilities acquired in September 2014 and one solar facility acquired in December 2014.
2 Includes our 50 per cent ownership interest of Sundance B volumes through the ASTC Power Partnership.
3 The percentage of time the plant was available to generate power, regardless of whether it was running.
4 Does not include facilities that provide power to us under PPAs.
5 Does not include Bécancour because power generation has been suspended since 2008.

Western Power

Comparable EBITDA for Western Power decreased by $57 million for the three months ended March 31, 2015 compared to the same period in 2014 due to lower realized power prices and the sale of Cancarb in April 2014.

Average spot market power prices in Alberta decreased by 53 per cent from $62/MWh to $29/MWh for the three months ended March 31, 2015 compared to the same period in 2014. The Alberta power market remained well supplied in first quarter 2015, with strong thermal fleet availability, robust wind output and new capacity from a large gas-fired power plant that entered commercial service in March 2015. Mild winter weather conditions also contributed to the lower power prices.

Lower Alberta spot power prices experienced in first quarter 2015 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-four per cent of Western Power sales volumes were sold under contract in first quarter 2015 compared to 72 per cent in first quarter 2014.

Eastern Power

Comparable EBITDA for Eastern Power increased by $38 million for the three months ended March 31, 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 2014.

BRUCE POWER
Our proportionate share

	three months ended March 31	
(unaudited - millions of $, unless noted otherwise)	**2015**	**2014**
Income from equity investments[1]		
Bruce A	**56**	49
Bruce B	**23**	15
	79	64
Comprised of:		
Revenues	**331**	300
Operating expenses	**(172)**	(157)
Depreciation and other	**(80)**	(79)
	79	64
Bruce Power - Other information		
Plant availability[2]		
Bruce A	**89%**	80%
Bruce B	**97%**	85%
Combined Bruce Power	**93%**	83%
Planned outage days		
Bruce A	**39**	—
Bruce B	**—**	49
Unplanned outage days		
Bruce A	**—**	60
Bruce B	**9**	—
Sales volumes (GWh)[1]		
Bruce A	**2,819**	2,527
Bruce B	**2,165**	1,924
	4,984	4,451
Realized sales price per MWh[3]		
Bruce A	**$72**	$71
Bruce B	**$54**	$56
Combined Bruce Power	**$62**	$63

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 $7 million for the three months ended March 31, 2015 compared to the same period in 2014. The increase was mainly due to higher volumes resulting from fewer outage days partially offset by higher operating expenses.

Equity income from Bruce B increased $8 million for the three months ended March 31, 2015 compared to the same period in 2014 mainly due to higher volumes resulting from fewer outage days.

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 April 2015, all Bruce B units were removed from service for approximately one month to allow for inspection of the Bruce B vacuum building as mandated by the Canadian Nuclear Safety Commission to occur approximately once every decade. Additional planned maintenance on Unit 6 will continue during second quarter 2015. Planned maintenance at Bruce A is scheduled for third quarter 2015.

U.S. POWER

	three months ended March 31	
(unaudited - millions of US$)	**2015**	**2014**
Revenue		
Power[1]	**605**	743
Capacity	**67**	70
	672	813
Commodity purchases resold	**(476)**	(549)
Plant operating costs and other[2]	**(117)**	(180)
Exclude risk management activities[1]	**54**	2
Comparable EBITDA	**133**	86
Comparable depreciation and amortization	**(27)**	(27)
Comparable EBIT	**106**	59

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

	three months ended March 31	
(unaudited)	**2015**	**2014**
Physical sales volumes (GWh)		
Supply		
Generation	**914**	1,238
Purchased	**4,670**	3,207
	5,584	4,445
Plant availability[1,2]	**61%**	85%

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

U.S. Power - other information

	three months ended March 31	
(unaudited)	**2015**	**2014**
Average Spot Power Prices (US$ per MWh)		
New England	86	145
New York[1]	74	134
Average New York[1] Spot Capacity Prices (US$ per KW-M)	8.34	9.64

1 Represents Zone J in New York City where the Ravenswood plant operates.

Comparable EBITDA for U.S. Power increased US$47 million for the three months ended March 31, 2015 compared to the same period in 2014 and was 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 power prices and generation at our facilities in New York and New England partially offset by higher margins and higher sales to wholesale, commercial and industrial customers.

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 2013/2014 and the impact on the pricing of our 2015 contracts in the New England market, these timing differences will be more significant in 2015. The majority of these higher earnings will be offset by lower earnings in second quarter.

Wholesale electricity prices in New York and New England were significantly lower for the three months ended March 31, 2015 compared to the same period in 2014 despite colder temperatures in the northeast U.S. in 2015. Spot power prices for the three months ended March 31, 2015 were 41 per cent lower in New England and 45 per cent lower in New York City compared to the same period in 2014. Spot capacity prices in New York City were, on average, 13 per cent lower for the three months ended March 31, 2015 compared to the same period 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 in first quarter 2015 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 for the three months ended March 31, 2015 were higher compared to the same period in 2014. For the three months ended March 31, 2015, purchased volumes sold to wholesale, commercial and industrial customers were higher than the same period in 2014 offset by lower generation volumes primarily at our Ravenswood and hydro facilities.

As at March 31, 2015, approximately 3,900 GWh or 44 per cent of U.S. Power's planned generation was contracted for the remainder of 2015, and 3,500 GWh or 31 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 decreased $24 million for the three months ended March 31, 2015 compared to the same period in 2014 and was 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 $6.7 billion of new supply and demand facilities under development. In first quarter 2015, we continued to advance several of these capital expansion projects by filing the regulatory applications with the NEB and plan to file additional facilities applications for this program throughout 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. Subject to certain conditions, including a positive final investment decision on the proposed PNW LNG project, we expect to have the Aitken Creek Section in service in 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.

Canadian Mainline

TransCanada Mainline - 2013-2030 Mainline Settlement Application Compliance Filing
On March 31, 2015, we submitted a compliance filing in response to direction from the NEB's RH-001-2014 Decision issued in November 2014. We are currently operating under interim tolls set out at the level proposed in the initial application and will continue until final tolls are approved through this compliance filing.

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. The US$446 million sale is comprised of US$253 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. 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
We anticipate decisions in second quarter 2015 from the B.C. Oil and Gas Commission (BC OGC) on the permits to build and operate the Prince Rupert Gas Transmission pipeline project.

Coastal GasLink
We anticipate decisions in second quarter 2015 from the BC OGC on the permits to build and operate the Coastal GasLink pipeline project.

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 the 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 have been received.

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 has not fully and completely assessed the environmental impacts of Keystone XL and that, at lower 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 but also offering 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.

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 March 31, 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 potential reclassification of beluga whales as an endangered species. We are currently evaluating other options and discussing those options with our shippers. Amendments to the project are expected to be

submitted to the NEB in fourth quarter 2015. The alteration to the project scope and further refinement of the project schedule is expected to result in an in-service date of 2020.

Binding long term contracts of approximately one million Bbl/d for the 1.1 million Bbl/d pipeline have been secured. The project is estimated to cost approximately $12 billion, excluding the transfer value of Canadian Mainline natural gas assets.

Upland Pipeline

On April 22, 2015, we filed an application to obtain a U.S. Presidential Permit for the Upland Pipeline. The $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 Energy East proceeding.

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 March 31	
(unaudited - millions of $)	**2015**	**2014**
Comparable interest on long-term debt (including interest on junior subordinated notes)		
Canadian-dollar denominated	**(109)**	(114)
U.S. dollar-denominated (US$)	**(218)**	(207)
Foreign exchange impact	**(48)**	(22)
	(375)	(343)
Other interest and amortization expense	**(13)**	(10)
Capitalized interest	**70**	79
Comparable interest expense	**(318)**	(274)
Specific items[1]	**—**	—
Interest expense	**(318)**	(274)

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

Comparable interest expense increased by $44 million for the three months ended March 31, 2015 compared to the same period in 2014 because of the following:

- higher interest expense due to debt issues of:
  - 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 foreign exchange impact on interest expense related to U.S. dollar-denominated debt
- lower capitalized interest primarily due to the completion of the Gulf Coast extension of the Keystone Pipeline System in first quarter 2014.

	three months ended March 31	
(unaudited - millions of $)	**2015**	**2014**
Comparable interest income and other expense	**15**	(6)
Specific items (pre-tax):		
Risk management activities	**(29)**	(2)
Interest income and other expense	**(14)**	(8)

Comparable interest income and other expense increased by $21 million for the three months ended March 31, 2015 compared to the same period 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 March 31 2015	2014
Comparable income tax expense	**(247)**	(224)
Specific items:		
Risk management activities	**40**	3
Income tax expense	**(207)**	(221)

Comparable income tax expense increased by $23 million for the three months ended March 31, 2015 compared to the same period 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 March 31 2015	2014
Net income attributable to non-controlling interests	**(59)**	(54)
Preferred share dividends	**(23)**	(23)

Net income attributable to non-controlling interests increased by $5 million for the three months ended March 31, 2015 compared to the same period in 2014 primarily due to the sale of our remaining 30 per cent direct interest in Bison to TC PipeLines, LP in October 2014 and the positive impact of a strong 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 March 31 2015	2014
Funds generated from operations[1]	**1,153**	1,102
Increase in operating working capital	**(393)**	(123)
Net cash provided by operations	**760**	979

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

At March 31, 2015, our current assets were $5.1 billion and current liabilities were $8.2 billion, leaving us with a working capital deficit of $3.1 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 March 31 2015	2014
Capital expenditures	**(806)**	(744)
Capital projects under development	**(201)**	(104)
Equity investments	**(93)**	(89)
Deferred amounts and other	**263**	47
Net cash used in investing activities	**(837)**	(890)

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

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

CASH PROVIDED BY/(USED IN) FINANCING ACTIVITIES

(unaudited - millions of $)	three months ended March 31 2015	2014
Long-term debt issued, net of issue costs	**2,277**	1,364
Repayment of long-term debt	**(1,016)**	(777)
Notes payable issued/(repaid), net	**279**	(747)
Dividends and distributions paid	**(417)**	(390)
Common shares issued, net of issue costs	**10**	10
Partnership units of subsidiary issued, net of issue costs	**4**	—
Preferred shares issued, net of issue costs	**243**	440
Preferred shares of subsidiary redeemed	**—**	(200)
Net cash provided by/(used in) financing activities	**1,380**	(300)

LONG-TERM DEBT ISSUED

Company (unaudited - millions of $)	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%

LONG-TERM DEBT RETIRED

Company (unaudited - millions of $)	Retirement date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	March 2015	Senior Unsecured Notes	US 500	0.875%
	January 2015	Senior Unsecured Notes	US 300	4.875%

PREFERRED SHARE ISSUANCE

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. Investors are entitled to receive fixed cumulative dividends at an annual rate of $0.95 per share, payable quarterly. The dividend rate will reset on November 30, 2020 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 2.96 per cent. The preferred shares are redeemable by us on November 30, 2020 and on the last business day in November of every fifth year thereafter at a price of $25 per share plus accrued and unpaid dividends. The Series 11 preferred shareholders will have the right to convert their shares into Series 12 cumulative redeemable first preferred shares on November 30, 2020 and on the last business day in November of every fifth year thereafter. The holders of Series 12 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at an annualized rate equal to the then 90-day Government of Canada treasury bill rate and 2.96 per cent.

The net proceeds of the above debt and 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

In first quarter 2015, fifty-five thousand common units were issued under the ATM program generating net proceeds of approximately US$3 million. Our ownership interest in TC PipeLines, LP will decrease as a result of the ATM program.

DIVIDENDS

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

Quarterly dividend on our common shares
$0.52 per share
Payable on July 31, 2015 to shareholders of record at the close of business on June 30, 2015

Quarterly dividends on our preferred shares	
Series 1	$0.2041
Series 2	$0.1488
Series 3	$0.25
Payable on June 30, 2015 to shareholders of record at the close of business on June 1, 2015	
Series 5	$0.275
Series 7	$0.25
Series 9	$0.2656
Payable on July 30, 2015 to shareholders of record at the close of business on June 30, 2015	
Series 11	$0.229
Payable on May 29, 2015 to shareholders of record at the close of business on May 12, 2015	

SHARE INFORMATION

as at April 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	14 million	Series 4 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**
	6 million	10 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 March 31, 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	$0.5 billion	TCPL, TCPL USA	Demand lines for issuing letters of credit and as a source of additional liquidity. At March 31, 2015, we had $0.9 billion outstanding in letters of credit under these lines	Demand

At March 31, 2015, our operated affiliates had $0.4 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 $0.4 billion since December 31, 2014 primarily due to the completion or advancement of capital projects. Our other purchase obligations have increased by approximately $0.2 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 first 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 March 31, 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 $241 million (US$190 million) and $258 million (US$222 million) at March 31, 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) 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

First quarter 2015	1.24
First quarter 2014	1.11

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

	three months ended March 31	
(unaudited - millions of US$)	**2015**	2014
U.S. and International Natural Gas Pipelines comparable EBIT	**241**	211
U.S. Liquids Pipelines comparable EBIT	**149**	129
U.S. Power comparable EBIT	**106**	59
Interest expense on U.S. dollar-denominated long-term debt	**(218)**	(207)
Capitalized interest on U.S. dollar-denominated capital expenditures	**31**	52
U.S. non-controlling interests and other	**(79)**	(79)
	230	165

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:

	March 31, 2015		December 31, 2014	
(unaudited - millions of $)	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]	**(670)**	**US 2,700**	(431)	US 2,900
U.S. dollar foreign exchange forward contracts				
(maturing 2015)	**(91)**	**US 3,500**	(28)	US 1,400
	(761)	**US 6,200**	(459)	US 4,300

1 Fair values equal carrying values.
2 Net income in the three months ended March 31, 2015 included net realized gains of $3 million (2014 - gains of $6 million) related to the interest component of cross-currency swaps settlements.

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

(unaudited - millions of $)	March 31, 2015	December 31, 2014
Carrying value	**19,500 (US 15,400)**	17,000 (US 14,700)
Fair value	**22,700 (US 17,900)**	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 $)	March 31, 2015	December 31, 2014
Other current assets	**63**	5
Intangible and other assets	**2**	1
Accounts payable and other	**(370)**	(155)
Other long-term liabilities	**(456)**	(310)
	(761)	(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. The fair value of available for sale assets has been calculated using quoted market prices where available. Credit risk has been taken into consideration when calculating the fair value of non-derivative financial instruments.

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 be classified in Level II of the fair value hierarchy.

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 $)	March 31, 2015	December 31, 2014
Other current assets	**543**	409
Intangible and other assets	**153**	93
Accounts payable and other	**(1,039)**	(749)
Other long-term liabilities	**(662)**	(411)
	(1,005)	(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 March 31	
(unaudited - millions of $, pre-tax)	**2015**	**2014**
Derivative instruments held for trading[1]		
Amount of unrealized (losses)/gains in the period		
Power	**(26)**	9
Natural gas	**—**	(7)
Foreign exchange	**(29)**	(2)
Amount of realized (losses)/gains in the period		
Power	**(10)**	(28)
Natural gas	**11**	50
Foreign exchange	**(43)**	(17)
Derivative instruments in hedging relationships[2,3]		
Amount of realized gains in the period		
Power	**16**	192
Interest	**2**	1
Losses on ineffective portion in the period		
Power	**(63)**	(13)

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 months ended March 31, 2015, net realized gains on fair value hedges were $2 million (2014 - $1 million) and were included in interest expense. For the three months ended March 31, 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 months ended March 31, 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 is as follows:

	three months ended March 31	
(unaudited - millions of $, pre-tax)	**2015**	**2014**
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Power	**21**	41
Foreign exchange	**—**	10
	21	51
Reclassification of gains/(losses) on derivative instruments from AOCI to net income (effective portion)[1]		
Power[2]	**69**	(108)
Interest[3]	**4**	5
	73	(103)
Losses on derivative instruments recognized in net income (ineffective portion)		
Power	**(63)**	(13)
	(63)	(13)

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 March 31, 2015, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $31 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 March 31, 2015, we would have been required to provide collateral of $31 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 March 31, 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 first 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 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. This new guidance is effective from January 1, 2017 with 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. Early application is not permitted.

In April 2015, the FASB proposed deferring the effective date to January 1, 2018 and proposed permitting early adoption of the standard but not before the original effective date.

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 March 31	
(unaudited - millions of $, except per share amounts)	**2015**	2014
EBITDA	**1,442**	1,385
Non-comparable risk management activities affecting EBITDA	**89**	11
Comparable EBITDA	**1,531**	1,396
Comparable depreciation and amortization	**(434)**	(393)
Comparable EBIT	**1,097**	1,003
Other income statement items		
Comparable interest expense	**(318)**	(274)
Comparable interest income and other expense	**15**	(6)
Comparable income tax expense	**(247)**	(224)
Net income attributable to non-controlling interests	**(59)**	(54)
Preferred share dividends	**(23)**	(23)
Comparable earnings	**465**	422
Specific items (net of tax):		
Risk management activities[1]	**(78)**	(10)
Net income attributable to common shares	**387**	412
Comparable depreciation and amortization	**(434)**	(393)
Specific items[2]	**—**	—
Depreciation and amortization	**(434)**	(393)
Comparable interest expense	**(318)**	(274)
Specific items[2]	**—**	—
Interest expense	**(318)**	(274)
Comparable interest income and other expense	**15**	(6)
Specific items:		
Risk management activities[1]	**(29)**	(2)
Interest income and other expense	**(14)**	(8)
Comparable income tax expense	**(247)**	(224)
Specific items:		
Risk management activities[1]	**40**	3
Income tax expense	**(207)**	(221)
Comparable earnings per common share	**$0.66**	$0.60
Specific items (net of tax):		
Risk management activities[1]	**(0.11)**	(0.02)
Net income per common share	**$0.55**	$0.58

1

Risk management activities	three months ended March 31	
(unaudited - millions of $)	**2015**	**2014**
Canadian Power	**(22)**	—
U.S. Power	**(68)**	(2)
Natural Gas Storage	**1**	(9)
Foreign exchange	**(29)**	(2)
Income tax attributable to risk management activities	**40**	3
Total losses from risk management activities	**(78)**	(10)

2 There were no specific items in either of these periods.

Comparable EBITDA and EBIT by business segment

three months ended March 31, 2015 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	**874**	**309**	**299**	**(40)**	**1,442**
Non-comparable risk management activities affecting EBITDA	**—**	**—**	**89**	**—**	**89**
Comparable EBITDA	**874**	**309**	**388**	**(40)**	**1,531**
Comparable depreciation and amortization	**(279)**	**(63)**	**(85)**	**(7)**	**(434)**
Comparable EBIT	**595**	**246**	**303**	**(47)**	**1,097**

three months ended March 31, 2014 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	848	241	334	(38)	1,385
Non-comparable risk management activities affecting EBITDA	—	—	11	—	11
Comparable EBITDA	848	241	345	(38)	1,396
Comparable depreciation and amortization	(262)	(49)	(77)	(5)	(393)
Comparable EBIT	586	192	268	(43)	1,003

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

(unaudited - millions of $, except per share amounts)	2015	2014				2013		
	First	Fourth	Third	Second	First	Fourth	Third	Second
Revenues	**2,874**	2,616	2,451	2,234	2,884	2,332	2,204	2,009
Net income attributable to common shares	**387**	458	457	416	412	420	481	365
Comparable earnings	**465**	511	450	332	422	410	447	357
Share statistics								
Net income per common share - basic and diluted	**$0.55**	$0.72	$0.63	$0.59	$0.58	$0.59	$0.68	$0.52
Comparable earnings per share	**$0.66**	$0.65	$0.64	$0.47	$0.60	$0.58	$0.63	$0.51
Dividends declared per common share	**$0.52**	$0.48	$0.48	$0.48	$0.48	$0.46	$0.46	$0.46

FACTORS AFFECTING QUARTERLY FINANCIAL INFORMATION BY BUSINESS SEGMENT

Quarter-over-quarter revenues and net income sometimes fluctuate. The causes of these fluctuations 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 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.

In second quarter 2013, comparable earnings excluded a $25 million favourable income tax adjustment due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax in June 2013.

Condensed consolidated statement of income

(unaudited - millions of Canadian $, except per share amounts)	three months ended March 31 2015	2014
Revenues		
Natural Gas Pipelines	**1,305**	1,215
Liquids Pipelines	**443**	359
Energy	**1,126**	1,310
	2,874	2,884
Income from Equity Investments	**137**	135
Operating and Other Expenses		
Plant operating costs and other	**754**	805
Commodity purchases resold	**681**	706
Property taxes	**134**	123
Depreciation and amortization	**434**	393
	2,003	2,027
Financial Charges		
Interest expense	**318**	274
Interest income and other expense	**14**	8
	332	282
Income before Income Taxes	**676**	710
Income Tax Expense		
Current	**68**	59
Deferred	**139**	162
	207	221
Net Income	**469**	489
Net income attributable to non-controlling interests	**59**	54
Net Income Attributable to Controlling Interests	**410**	435
Preferred share dividends	**23**	23
Net Income Attributable to Common Shares	**387**	412
Net Income per Common Share		
Basic and diluted	**$0.55**	$0.58
Dividends Declared per Common Share	**$0.52**	$0.48
Weighted Average Number of Common Shares (millions)		
Basic	**709**	708
Diluted	**710**	708

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

	three months ended March 31	
(unaudited - millions of Canadian $)	**2015**	**2014**
Net Income	**469**	489
Other Comprehensive Income, Net of Income Taxes		
Foreign currency translation gains on net investment in foreign operations	**469**	240
Change in fair value of net investment hedges	**(266)**	(127)
Change in fair value of cash flow hedges	**15**	31
Reclassification to net income of gains and losses on cash flow hedges	**44**	(62)
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**7**	4
Other comprehensive income on equity investments	**3**	—
Other comprehensive income (Note 8)	**272**	86
Comprehensive Income	**741**	575
Comprehensive income attributable to non-controlling interests	**207**	98
Comprehensive Income Attributable to Controlling Interests	**534**	477
Preferred share dividends	**23**	25
Comprehensive Income Attributable to Common Shares	**511**	452

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of cash flows

(unaudited - millions of Canadian $)	three months ended March 31 2015	2014
Cash Generated from Operations		
Net income	**469**	489
Depreciation and amortization	**434**	393
Deferred income taxes	**139**	162
Income from equity investments	**(137)**	(135)
Distributed earnings received from equity investments	**135**	170
Employee post-retirement benefits expense, net of funding	**15**	10
Equity AFUDC	**(33)**	(5)
Unrealized losses on financial instruments	**118**	13
Other	**13**	5
Increase in operating working capital	**(393)**	(123)
Net cash provided by operations	**760**	979
Investing Activities		
Capital expenditures	**(806)**	(744)
Capital projects under development	**(201)**	(104)
Equity investments	**(93)**	(89)
Deferred amounts and other	**263**	47
Net cash used in investing activities	**(837)**	(890)
Financing Activities		
Dividends on common shares	**(341)**	(325)
Dividends on preferred shares	**(22)**	(20)
Distributions paid to non-controlling interests	**(54)**	(45)
Notes payable issued/(repaid), net	**279**	(747)
Long-term debt issued, net of issue costs	**2,277**	1,364
Repayment of long-term debt	**(1,016)**	(777)
Common shares issued, net of issue costs	**10**	10
Preferred shares issued, net of issue costs	**243**	440
Partnership units of subsidiary issued, net of issue costs	**4**	—
Preferred shares of subsidiary redeemed	**—**	(200)
Net cash provided by/(used in) financing activities	**1,380**	(300)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**29**	33
Increase/(decrease) in Cash and Cash Equivalents	**1,332**	(178)
Cash and Cash Equivalents		
Beginning of period	**489**	927
Cash and Cash Equivalents		
End of period	**1,821**	749

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		March 31, 2015	December 31, 2014
ASSETS			
Current Assets			
Cash and cash equivalents		**1,821**	489
Accounts receivable		**1,419**	1,313
Inventories		**280**	292
Other		**1,589**	1,446
		5,109	3,540
Plant, Property and Equipment,	net of accumulated depreciation of $20,303 and $19,563, respectively	**44,211**	41,774
Equity Investments		**5,735**	5,598
Regulatory Assets		**1,247**	1,297
Goodwill		**4,410**	4,034
Intangible and Other Assets		**3,104**	2,704
		63,816	58,947
LIABILITIES			
Current Liabilities			
Notes payable		**2,818**	2,467
Accounts payable and other		**2,852**	2,896
Accrued interest		**425**	424
Current portion of long-term debt		**2,112**	1,797
		8,207	7,584
Regulatory Liabilities		**529**	263
Other Long-Term Liabilities		**1,309**	1,052
Deferred Income Tax Liabilities		**5,561**	5,275
Long-Term Debt		**25,733**	22,960
Junior Subordinated Notes		**1,268**	1,160
		42,607	38,294
EQUITY			
Common shares, no par value		**12,212**	12,202
Issued and outstanding:	March 31, 2015 - 709 million shares		
	December 31, 2014 - 709 million shares		
Preferred shares		**2,499**	2,255
Additional paid-in capital		**373**	370
Retained earnings		**5,497**	5,478
Accumulated other comprehensive loss (Note 8)		**(1,111)**	(1,235)
Controlling Interests		**19,470**	19,070
Non-controlling interests		**1,739**	1,583
		21,209	20,653
		63,816	58,947

Contingencies and Guarantees (Note 11)

Subsequent Event (Note 12)

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of equity

	three months ended March 31	
(unaudited - millions of Canadian $)	**2015**	**2014**
Common Shares		
Balance at beginning of period	**12,202**	12,149
Shares issued on exercise of stock options	**10**	12
Balance at end of period	**12,212**	12,161
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	**2**	1
Dilution impact from TC PipeLines, LP units issued	**1**	—
Redemption of subsidiary's preferred shares	**—**	(6)
Balance at end of period	**373**	396
Retained Earnings		
Balance at beginning of period	**5,478**	5,096
Net income attributable to controlling interests	**410**	435
Common share dividends	**(369)**	(339)
Preferred share dividends	**(22)**	(25)
Balance at end of period	**5,497**	5,167
Accumulated Other Comprehensive Loss		
Balance at beginning of period	**(1,235)**	(934)
Other comprehensive income	**124**	42
Balance at end of period	**(1,111)**	(892)
Equity Attributable to Controlling Interests	**19,470**	19,087
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	**50**	45
Preferred share dividends of TCPL	**—**	2
Portland	**9**	7
Other comprehensive income attributable to non-controlling interests	**148**	44
Issuance of TC PipeLines, LP units		
Proceeds, net of issue costs	**4**	—
Decrease in TransCanada's ownership of TC Pipelines, LP	**(1)**	—
Distributions declared to non-controlling interests	**(54)**	(51)
Redemption of subsidiary's preferred shares	**—**	(194)
Foreign exchange and other	**—**	10
Balance at end of period	**1,739**	1,474
Total Equity	**21,209**	20,561

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. This new guidance is effective from January 1, 2017 with 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. Early application is not permitted.

In April 2015, the FASB proposed deferring the effective date to January 1, 2018 and proposed permitting early adoption of the standard but not before the original effective date.

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 March 31	**Natural Gas Pipelines**		**Liquids Pipelines**		**Energy**		**Corporate**		**Total**	
(unaudited - millions of Canadian $)	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**
Revenues	**1,305**	1,215	**443**	359	**1,126**	1,310	**—**	—	**2,874**	2,884
Income from equity investments	**54**	52	**—**	—	**83**	83	**—**	—	**137**	135
Plant operating costs and other	**(395)**	(333)	**(111)**	(101)	**(208)**	(333)	**(40)**	(38)	**(754)**	(805)
Commodity purchases resold	**—**	—	**—**	—	**(681)**	(706)	**—**	—	**(681)**	(706)
Property taxes	**(90)**	(86)	**(23)**	(17)	**(21)**	(20)	**—**	—	**(134)**	(123)
Depreciation and amortization	**(279)**	(262)	**(63)**	(49)	**(85)**	(77)	**(7)**	(5)	**(434)**	(393)
Segmented earnings	**595**	586	**246**	192	**214**	257	**(47)**	(43)	**1,008**	992
Interest expense									**(318)**	(274)
Interest income and other expense									**(14)**	(8)
Income before income taxes									**676**	710
Income tax expense									**(207)**	(221)
Net income									**469**	489
Net income attributable to non-controlling interests									**(59)**	(54)
Net income attributable to controlling interests									**410**	435
Preferred share dividends									**(23)**	(23)
Net income attributable to common shares									**387**	412

TOTAL ASSETS

(unaudited - millions of Canadian $)	March 31, 2015	December 31, 2014
Natural Gas Pipelines	**28,499**	27,103
Liquids Pipelines	**17,552**	16,116
Energy	**14,827**	14,197
Corporate	**2,938**	1,531
	63,816	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 March 31, 2015, regulatory liabilities included $50 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 March 31, 2015, intangible and other assets included $50 million (December 31, 2014 - nil) of restricted investments on the condensed consolidated balance sheet. Please refer to Note 10 for information on the fair values of these investments.

5. Income taxes

At March 31, 2015, the total unrecognized tax benefit of uncertain tax positions was approximately $25 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 months ended March 31, 2015 is nil of interest expense and nil for penalties (March 31, 2014 - $1 million of interest expense and nil for penalties). At March 31, 2015, the Company had $4 million accrued for interest expense and nil accrued for penalties (December 31, 2014 - $4 million accrued for interest expense and nil for penalties).

The effective tax rates for the three-month periods ended March 31, 2015 and 2014 were both 31 per cent.

6. Long-term debt

LONG-TERM DEBT ISSUED

The Company issued long-term debt for the three months ended March 31, 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%

LONG-TERM DEBT RETIRED

The Company retired long-term debt for the three months ended March 31, 2015 as follows:

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

In the three months ended March 31, 2015, TransCanada had capitalized interest related to capital projects of $70 million (2014 - $79 million).

7. Equity and share capital

PREFERRED SHARE ISSUANCE

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. Investors are entitled to receive fixed cumulative dividends at an annual rate of $0.95 per share, payable quarterly. The dividend rate will reset on November 30, 2020 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield plus 2.96 per cent. The preferred shares are redeemable by TransCanada on or after November 30, 2020 and on November 30 of every fifth year thereafter at a price of $25 per share plus accrued and unpaid dividends. The Series 11 preferred shareholders will have the right to convert their 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 a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate plus 2.96 per cent.

8. 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 March 31, 2015 (unaudited - millions of Canadian $)	**Before tax amount**	**Income tax recovery/ (expense)**	**Net of tax amount**
Foreign currency translation gains on net investment in foreign operations	**460**	**9**	**469**
Change in fair value of net investment hedges	**(359)**	**93**	**(266)**
Change in fair value of cash flow hedges	**21**	**(6)**	**15**
Reclassification to net income of gains and losses on cash flow hedges	**73**	**(29)**	**44**
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**10**	**(3)**	**7**
Other comprehensive income on equity investments	**4**	**(1)**	**3**
Other comprehensive income	**209**	**63**	**272**

three months ended March 31, 2014 (unaudited - millions of Canadian $)	**Before tax amount**	**Income tax recovery/ (expense)**	**Net of tax amount**
Foreign currency translation gains on net investment in foreign operations	191	49	240
Change in fair value of net investment hedges	(171)	44	(127)
Change in fair value of cash flow hedges	51	(20)	31
Reclassification to net income of gains and losses on cash flow hedges	(103)	41	(62)
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	6	(2)	4
Other comprehensive (loss)/income	(26)	112	86

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

three months ended March 31, 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 before reclassifications[2]	**55**	**15**	**—**	**—**	**70**
Amounts reclassified from accumulated other comprehensive loss[3]	**—**	**44**	**7**	**3**	**54**
Net current period other comprehensive income	**55**	**59**	**7**	**3**	**124**
AOCI balance at March 31, 2015	**(463)**	**(69)**	**(274)**	**(305)**	**(1,111)**

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 gains of $148 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 $12 million ($5 million, net of tax) at March 31, 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**
(unaudited - millions of Canadian $)	**three months ended March 31, 2015**	**three months ended March 31, 2014**	
Cash flow hedges			
Power and Natural Gas	**(69)**	**108**	Revenue (Energy)
Interest	**(4)**	**(5)**	Interest expense
	(73)	**103**	Total before tax
	29	**(41)**	Income tax expense
	(44)	**62**	Net of tax
Pension and OPEB plan adjustments			
Amortization of actuarial loss and past service cost[2]	**(10)**	**(6)**	
	3	**2**	Income tax expense
	(7)	**(4)**	Net of tax
Equity Investments			
Equity income	**(4)**	**—**	Income from equity investments
	1	**—**	Income tax expense
	(3)	**—**	Net of tax

1 All amounts in parentheses indicate expenses to the condensed consolidated statement of income.
2 These accumulated other comprehensive loss components are included in the computation of net benefit cost. Refer to Note 9 for additional detail.

9. Employee post-retirement benefits

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

	three months ended March 31			
	Pension benefit plans		Other post-retirement benefit plans	
(unaudited - millions of Canadian $)	**2015**	2014	**2015**	2014
Service cost	**27**	22	**1**	1
Interest cost	**28**	28	**2**	2
Expected return on plan assets	**(38)**	(35)	**—**	—
Amortization of actuarial loss	**9**	5	**1**	1
Amortization of regulatory asset	**6**	5	**—**	—
Net benefit cost recognized	**32**	25	**4**	4

10. Risk management and financial instruments

RISK MANAGEMENT OVERVIEW

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

COUNTERPARTY CREDIT RISK

TransCanada's maximum counterparty credit exposure with respect to financial instruments at March 31, 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 March 31, 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 $241 million (US$190 million) and $258 million (US$222 million) at March 31, 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)	March 31, 2015	December 31, 2014
Carrying value	**19,500 (US 15,400)**	17,000 (US 14,700)
Fair value	**22,700 (US 17,900)**	19,000 (US 16,400)

Derivatives designated as a net investment hedge

(unaudited - millions of Canadian $, unless noted otherwise)	March 31, 2015 Fair value[1]	March 31, 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]	**(670)**	**US 2,700**	(431)	US 2,900
U.S. dollar foreign exchange forward contracts				
(maturing 2015)	**(91)**	**US 3,500**	(28)	US 1,400
	(761)	**US 6,200**	(459)	US 4,300

1 Fair values equal carrying values.
2 Net income in the three months ended March 31, 2015 included net realized gains of $3 million (2014 - gains of $6 million) related to the interest component of cross-currency swaps which is included 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 $)	March 31, 2015	December 31, 2014
Other current assets	**63**	5
Intangible and other assets	**2**	1
Accounts payable and other	**(370)**	(155)
Other long-term liabilities	**(456)**	(310)
	(761)	(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. The fair value of available for sale assets has been calculated using quoted market prices where available. Credit risk has been taken into consideration when calculating the fair value of non-derivative instruments.

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 be classified in Level II of the fair value hierarchy.

Balance sheet presentation of non-derivative financial instruments

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

(unaudited - millions of Canadian $)	March 31, 2015		December 31, 2014	
	Carrying amount	Fair value	Carrying amount	Fair value
Notes receivable and other[1]	**191**	**240**	213	263
Current and long-term debt[2,3]	**(27,845)**	**(33,385)**	(24,757)	(28,713)
Junior subordinated notes	**(1,268)**	**(1,240)**	(1,160)	(1,157)
	(28,922)	**(34,385)**	(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$500 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 months ended March 31, 2015 included losses of $6 million (2014 - losses of $6 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$500 million of long-term debt at March 31, 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.

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 $)	March 31, 2015	December 31, 2014
Other current assets	**543**	409
Intangible and other assets	**153**	93
Accounts payable and other	**(1,039)**	(749)
Other long-term liabilities	**(662)**	(411)
	(1,005)	(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	**$458**	**$72**	**$3**	**$4**
Liabilities	**($527)**	**($109)**	**($63)**	**($4)**
Notional values[3]				
Volumes[4]				
Purchases	**54,058**	**99**	**—**	**—**
Sales	**42,469**	**54**	**—**	**—**
U.S. dollars	**—**	**—**	**US 1,917**	**US 100**
Net unrealized losses in the period[5]				
three months ended March 31, 2015	**($26)**	**$—**	**($29)**	**$—**
Net realized (losses)/gains in the period[5]				
three months ended March 31, 2015	**($10)**	**$11**	**($43)**	**$—**
Maturity dates[3]	**2015-2019**	**2015-2020**	**2015-2016**	**2015-2016**
Derivative instruments in hedging relationships[6,7]				
Fair values[2,3]				
Assets	**$88**	**$—**	**$—**	**$6**
Liabilities	**($169)**	**$—**	**$—**	**($3)**
Notional values[3]				
Volumes[4]				
Purchases	**11,648**	**—**	**—**	**—**
Sales	**3,972**	**—**	**—**	**—**
U.S. dollars	**—**	**—**	**—**	**US 650**
Net realized gains in the period[5]				
three months ended March 31, 2015	**$16**	**$—**	**$—**	**$2**
Maturity dates[3]	**2015-2019**	**—**	**—**	**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 March 31, 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 $6 million and a notional amount of US$500 million as at March 31, 2015. For the three months ended March 31, 2015, net realized gains on fair value hedges were $2 million and were included in interest expense. For the three months ended March 31, 2015, the Company did not record any amounts in net income related to ineffectiveness for fair value hedges.

7 For the three months ended March 31, 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 March 31, 2014	$9	($7)	($2)	$—
Net realized (losses)/gains in the period[5]				
three months ended March 31, 2014	($28)	$50	($17)	$—
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 unrealized gains in the period[5]				
three months ended March 31, 2014	$192	$—	$—	$1
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 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 months ended March 31, 2014 were $1 million and were included in interest expense. For the three months ended March 31, 2014, the Company did not record any amounts in net income related to ineffectiveness for fair value hedges.

7 For the three months ended March 31, 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 8) related to derivatives in cash flow hedging relationships are as follows:

	three months ended March 31	
(unaudited - millions of Canadian $, pre-tax)	**2015**	2014
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Power	**21**	41
Foreign exchange	**—**	10
	21	51
Reclassification of gains/(losses) on derivative instruments from AOCI to net income (effective portion)[1]		
Power[2]	**69**	(108)
Interest[3]	**4**	5
	73	(103)
Losses on derivative instruments recognized in net income (ineffective portion)		
Power	**(63)**	(13)
	(63)	(13)

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 March 31, 2015 (unaudited - millions of Canadian $)	**Gross derivative instruments presented on the balance sheet**	**Amounts available for offset[1]**	**Net amounts**
Derivative - Asset			
Power	**546**	**(389)**	**157**
Natural gas	**72**	**(60)**	**12**
Foreign exchange	**68**	**(61)**	**7**
Interest	**10**	**(1)**	**9**
Total	**696**	**(511)**	**185**
Derivative - Liability			
Power	**(696)**	**389**	**(307)**
Natural gas	**(109)**	**60**	**(49)**
Foreign exchange	**(889)**	**61**	**(828)**
Interest	**(7)**	**1**	**(6)**
Total	**(1,701)**	**511**	**(1,190)**

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 March 31, 2015, the Company had provided cash collateral of $494 million (December 31, 2014 - $459 million) and letters of credit of $19 million (December 31, 2014 - $26 million) to its counterparties. The Company held nil (December 31, 2014 - $1 million) in cash collateral and $6 million (December 31, 2014 - $1 million) in letters of credit from counterparties on asset exposures at March 31, 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 March 31, 2015, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $31 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 March 31, 2015, the Company would have been required to provide additional collateral of $31 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 assets and liabilities measured on a recurring basis, including both current and non-current portions, are categorized as follows:

at March 31, 2015 (unaudited - millions of Canadian $, pre-tax)	**Quoted prices in active markets (Level I)**[1]	**Significant other observable inputs (Level II)**[1]	**Significant unobservable inputs (Level III)**[1]	**Total**
Derivative instrument assets:				
Power commodity contracts	**—**	**542**	**4**	**546**
Natural gas commodity contracts	**39**	**24**	**9**	**72**
Foreign exchange contracts	**—**	**68**	**—**	**68**
Interest rate contracts	**—**	**10**	**—**	**10**
Derivative instrument liabilities:				
Power commodity contracts	**—**	**(685)**	**(11)**	**(696)**
Natural gas commodity contracts	**(104)**	**(5)**	**—**	**(109)**
Foreign exchange contracts	**—**	**(889)**	**—**	**(889)**
Interest rate contracts	**—**	**(7)**	**—**	**(7)**
Non-derivative financial instruments:				
Available for sale assets[2]	**—**	**117**	**—**	**117**
	(65)	**(825)**	**2**	**(888)**

1 There were no transfers from Level I to Level II or from Level II to Level III for the three months ended March 31, 2015.
2 Available for sale assets (including restricted investments) are included in intangible and other assets on the condensed consolidated balance sheet.

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)
Non-derivative financial instruments:				
Available for sale assets[2]	—	75	—	75
	(46)	(541)	4	(583)

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.
2 Available for sale assets are included in intangible and other assets on the condensed consolidated balance sheet.

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

(unaudited - millions of Canadian $, pre-tax)	**three months ended March 31** **2015**	**2014**
Balance at beginning of period	**4**	1
Total losses included in net income	**(3)**	—
Total gains included in OCI	**1**	—
Balance at end of period	**2**	1

1 For the three months ended March 31, 2015, energy revenues include unrealized losses attributed to derivatives in the Level III category that were still held at March 31, 2015 of $3 million (2014 - nil).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in less than a $1 million decrease or increase, respectively, in the fair value of outstanding derivative instruments included in Level III as at March 31, 2015.

11. 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 March 31, 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]	**604**	**6**	634	6
Other jointly owned entities	ranging to 2040	**108**	**14**	104	14
		712	**20**	738	20

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

12. Subsequent event

Gas Transmission Northwest LLC

On April 1, 2015, TransCanada completed the sale of its remaining 30 per cent interest in Gas Transmission Northwest LLC (GTN) to TC PipeLines, LP for an aggregate purchase price of US$446 million.