QuarterlyReport to Shareholders

TransCanada Reports 26 Per Cent Increase in Third Quarter Earnings Energy East Increases Growth Portfolio to $38 Billion

CALGARY, Alberta – **November 5, 2013** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced comparable earnings for third quarter 2013 of $447 million or $0.63 per share compared to $349 million or $0.50 per share for the same period in 2012, a 26 per cent increase on a per share basis. Net income attributable to common shares for third quarter 2013 was $481 million or $0.68 per share. Funds generated from operations for third quarter 2013 were $1.046 billion, a 21 per cent increase compared to $866 million for the same period in 2012. TransCanada's Board of Directors also declared a quarterly dividend of $0.46 per common share for the quarter ending December 31, 2013, equivalent to $1.84 per common share on an annualized basis.

"We generated another strong quarter of earnings and cash flow from our portfolio of critical energy infrastructure assets, despite challenges in U.S. natural gas pipelines and cyclical lows in our gas storage business," said Russ Girling, TransCanada's president and chief executive officer. "Comparable earnings for the first nine months of 2013 were $1.66 per share, a 15 per cent increase over the same period last year and reflects the return to an eight unit site at Bruce Power, higher Alberta power prices, an increase in New York capacity prices and a higher Canadian Mainline allowed return on equity. Our strong earnings performance has also led to $2.9 billion of cash flow from existing operations year-to-date, an 18 per cent increase compared to the same period last year."

We are currently in the midst of an unprecedented capital program that will see a significant expansion of our three core businesses. With Energy East, we now have over $38 billion of commercially secured capital projects, which are backed by long-term contracts or cost of service business models. Our portfolio includes approximately $23 billion of crude oil pipelines, $13 billion of natural gas pipelines, and $2 billion of power generation facilities. Over the remainder of the decade, subject to required approvals, our blue-chip portfolio of contracted projects is expected to generate significant growth in earnings and cash flow.

Highlights

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

- Third quarter financial results
  - Net income attributable to common shares of $481 million or $0.68 per share
  - Comparable earnings of $447 million or $0.63 per share
  - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.257 billion
  - Funds generated from operations of $1.046 billion
- Declared a quarterly dividend of $0.46 per common share for the quarter ending December 31
- Secured commercial support for the $12 billion Energy East Pipeline project that will transport crude oil from western receipt points to eastern Canadian markets and export terminals
- Construction on the US$2.3 billion Gulf Coast Project, excluding the Houston Lateral, is now 95 per cent complete
- Finalized agreements for the North Montney Project, an approximate $1.7 billion extension of the NGTL System that will also include an interconnection with our proposed Prince Rupert Gas Transmission (PRGT) project
- Received National Energy Board (NEB) approval of settlement with shippers on the NGTL System for 2013 and 2014 on November 1
- Reached a long-term settlement with local distribution companies on the Canadian Mainline
- Sundance A Unit 1 returned to service in September 2013, followed by Unit 2 in October 2013
- Acquired two additional Ontario Solar projects for $99 million on September 30
- Closed the sale of a 45 per cent interest in each of GTN and Bison to TC PipeLines, LP for US$1.05 billion on July 1

Comparable earnings for third quarter 2013 were $447 million or $0.63 per share compared to $349 million or $0.50 per share for the same period in 2012. Higher earnings from the Canadian Mainline, Western Power, Bruce Power and U.S. Power were partially offset by lower contributions from U.S. Natural Gas Pipelines.

Net income attributable to common shares for third quarter 2013 was $481 million or $0.68 per share compared to $369 million or $0.52 per share in third quarter 2012.

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

Oil Pipelines:

- *Energy East Pipeline:* On August 1, 2013, we announced we are moving forward with the 1.1 million barrels per day (bbl/d) Energy East Pipeline project after receiving approximately 900,000 bbl/d of firm, long-term contracts during an open season to transport crude oil from western Canada to eastern refineries and export terminals. The project is estimated to cost approximately $12 billion excluding the transfer value of Canadian Mainline natural gas assets and, subject to regulatory approvals, is anticipated to be in service by late 2017 for deliveries in Québec and 2018 for deliveries in New Brunswick. We intend to file the necessary regulatory applications for approvals to construct and operate the pipeline project and terminal facilities in the first half of 2014.

- *Gulf Coast Project*: We are constructing a US$2.3 billion, 36-inch pipeline from Cushing, Oklahoma to the U.S. Gulf Coast and expect to begin delivering crude oil to Port Arthur, Texas near the end of 2013. Construction is approximately 95 per cent complete.

  We have commenced construction of the US$300 million 76 kilometre (km) (47 mile) Houston Lateral pipeline to transport crude oil to Houston, Texas refineries, which is expected to be complete in 2014.

  The Gulf Coast Project will have a capacity of up to 700,000 bbl/d.

- *Keystone XL:* On March 1, 2013, the U.S. Department of State (DOS) released its Draft Supplemental Environmental Impact Statement for the Keystone XL Pipeline. The impact statement reaffirmed that construction of the proposed pipeline from the U.S./Canada border in Montana to Steele City, Nebraska would not result in any significant impact to the environment. The DOS continues to review comments on the impact statement that it received during a public comment period that ended on April 22, 2013. Once the DOS has completed its review, it is anticipated it will issue a Final Supplemental Environmental Impact Statement and then consult with other governmental agencies and provide an additional opportunity for public comment during a National Interest Determination period of up to 90 days, before making a decision on our Presidential Permit application.

  We anticipate the pipeline to be in service approximately two years following the receipt of the Presidential Permit. The US$5.3 billion cost estimate will increase depending on the timing of the permit. As of September 30, 2013, we had invested US$2.0 billion in the project.

- *Northern Courier Pipeline:* In April 2013, we filed a permit application with the Alberta regulator after completing the required Aboriginal and stakeholder engagement and associated field work.

  On October 30, 2013, Suncor Energy announced that the Fort Hills Energy Limited Partnership is proceeding with the Fort Hills oil sands mining project and expects to begin producing crude oil as early as late 2017. Our Northern Courier Pipeline project is expected to be completed in 2017 and will transport crude oil from the Fort Hills mine site to Suncor's tank facilities located north of Fort McMurray.

- *Heartland Pipeline and TC Terminals*: We filed a permit application for the terminal facility with the Alberta regulator on May 30, 2013 and filed an application for the pipeline on October 25, 2013. The proposed projects will include a 200 km (125 mile) crude oil pipeline connecting the Edmonton region to facilities in Hardisty, Alberta, and a terminal facility in the Heartland industrial area north of Edmonton. The pipeline will be capable of transporting up to 900,000 bbl/d, while the terminal is expected to have storage capacity for up to 1.9 million barrels of crude oil. These projects together have a combined cost estimated at $900 million and are expected to come into service during the second half of 2015.

Natural Gas Pipelines:

- *Canadian Mainline:* On July 1, 2013, we implemented the NEB decision on our application to change the business structure and the terms and conditions of service for the Canadian Mainline. Since implementation of the decision, an additional 1.3 billion cubic feet per day (Bcf/d) of firm service originating at Empress has been contracted for, more than doubling the contracted capacity at this location.

  Certain additional changes to the Canadian Mainline's tariff were considered as a separate application that was heard in an oral hearing that concluded on September 23, 2013. The changes requested included provisions to diversions and alternate receipt points and modifying renewal notification for firm Mainline service. The NEB denied the material changes in its decision issued on October 10, 2013, with reasons to follow.

In September 2013, we reached a settlement with local natural gas distribution companies in Ontario and Québec on long-term tolls that will allow us to provide customers with the flexibility to source gas from various geographic locations within the eastern triangle segment of the system while ensuring that the tolls for the Canadian Mainline are set at levels that recover the costs of providing that flexibility. We expect to file an application for approval of the settlement with the NEB by the end of 2013 that includes a January 1, 2015 implementation date.

- *NGTL System Expansion:* We continue to expand the NGTL System and have placed approximately $700 million of new facilities into service in 2013. We have received NEB approval to construct approximately $300 million of additional facilities.

  In August 2013, we signed agreements with Progress Energy Canada Ltd. (Progress) for approximately 2 Bcf/d of firm gas transportation services to underpin the development of a major pipeline extension of the NGTL System. The proposed North Montney Project, which is expected to cost approximately $1.7 billion, will also include an interconnection with our proposed PRGT project to provide natural gas supply to the proposed Pacific NorthWest LNG export facility near Prince Rupert, British Columbia (B.C.). Under the commercial arrangements with Progress, receipt volumes are expected to increase between 2016 and 2019 to an aggregate volume of approximately 2.0 Bcf/d and delivery volumes to the PRGT project are expected to be approximately 2.1 Bcf/d beginning in 2019. We are also in discussions with other parties that have expressed interest in obtaining transportation services that would utilize the North Montney facilities. We plan to file an application with the NEB for approval to construct and operate the North Montney Project in fourth quarter 2013.

  We also expect to begin a notification process to potential shippers in fourth quarter 2013 for a proposal to provide export delivery service to Vanderhoof, B.C. through the use of capacity arrangements on the proposed Coastal GasLink pipeline.

- *NGTL System Rate Settlement:* A settlement on the NGTL System annual revenue requirement for the years 2013 and 2014 was reached with shippers and other interested parties in August 2013. The settlement fixes the allowed return on equity at 10.10 per cent on 40 per cent deemed common equity, establishes an increase in the composite depreciation rate to 3.05 per cent and 3.12 per cent for 2013 and 2014, respectively, and fixes the operations, maintenance and administration costs for 2013 at $190 million and 2014 at $198 million with any variance to our account. We filed an application with the NEB for approval of the settlement and final 2013 rates. We requested and received approval for changes to existing interim rates to reflect the settlement, effective September 1, 2013, pending a decision on the settlement application. On November 1, 2013, the NEB approved the settlement and 2013 final tolls, as filed. Third quarter 2013 results do not reflect the impact of this decision.

- *ANR Lebanon Lateral Reversal Project:* Following a successful binding open season which concluded in October 2013, we have executed firm transportation contracts for 350 million cubic feet per day at maximum tariff rates for 10 years on the ANR Lebanon Lateral Reversal project. The project will require modification to existing facilities at relatively minor capital expenditures, which are expected to be completed in first quarter 2014. Contracted volumes will increase over the course of 2014 generating incremental earnings. The project will substantially increase our ability to receive gas on ANR's southeast mainline from the Utica/Marcellus shale plays.

- *Great Lakes:* On September 27, 2013, we filed with the Federal Energy Regulatory Commission (FERC) a settlement with our customers to modify the transportation rates beginning on November 1, 2013. The settlement is expected to be approved by FERC before the end of the year. The settlement establishes maximum recourse transportation rates on the Great Lakes system. Commencing November 2013, rates will increase, compared to current rates, by approximately 21 per cent. This will result in a modest increase in the portion of Great Lakes' revenue derived from its recourse rate contracts. The settlement includes a moratorium on filing rate cases or challenging the settlement rates between November 1, 2013 and March 31, 2015 and requires that we file to have new rates in effect no later than January 1, 2018.

- *Mexican Pipelines:* The construction of the Tamazunchale Pipeline Extension project and related compression facilities is proceeding. Although the end of first quarter 2014 continues to be the target in-service date, the construction schedule has been challenged with various issues including the discovery of several archaeological finds. The project team continues to monitor and evaluate impacts of related schedule delays. The Topolobampo and Mazatlan projects in northwest Mexico are advancing as planned with engineering and permitting activities.

Energy:

- *Sundance A:* Unit 1 returned to service in early September 2013 and we have realized earnings from production since that time for the unit. Unit 2 returned to service in early October 2013. TransAlta shut down both units in December 2010 and was ordered by an arbitration panel in July 2012 to rebuild the units. Combined, Units 1 and 2 are capable of generating 560 megawatts (MW).

- *Ontario Solar:* In late 2011, we agreed to buy nine Ontario solar projects (combined capacity of 86 MW) from Canadian Solar Solutions Inc. for approximately $470 million. On June 28, 2013, we completed the acquisition of the first project for $55 million which has a capacity of 10 MW. On September 30, 2013, we completed the acquisition of two additional projects for $99 million which have a combined capacity of 16 MW. We expect the acquisition of the remaining projects to close in various stages throughout late 2013 and 2014, all subject to satisfactory completion of the related construction activities and regulatory approvals. All power produced will be sold under 20-year power purchase arrangements with the Ontario Power Authority.

Corporate:

- Our Board of Directors declared a quarterly dividend of $0.46 per share for the quarter ending December 31, 2013 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $1.84 per common share on an annual basis.

- On July 1, 2013, we completed the sale of a 45 per cent interest in each of Gas Transmission Northwest LLC (GTN) and Bison Pipeline LLC (Bison) to our master limited partnership, TC PipeLines, LP, for an aggregate purchase price of US$1.05 billion which includes US$146 million for 45 per cent of GTN's debt, plus normal closing adjustments. The proceeds from the sale will contribute to funding a portion of our capital program. We continue to hold a 30 per cent ownership interest in both pipelines. We also hold a 28.9 per cent interest in TC PipeLines, LP. The transaction demonstrates one of the many financing options available to us as we execute on our unprecedented growth portfolio.

  In July 2013, TC PipeLines, LP entered into a five-year, US$500 million term loan, maturing July 2018. The proceeds from the term loan were used to partially finance the acquisition of the 45 per cent interest in GTN and Bison.

- In July 2013, we issued US$500 million of three-year LIBOR-based floating rate notes maturing on June 30, 2016, bearing interest at an initial annual rate of 0.95 per cent.

  Also in July 2013, we issued $450 million and $300 million of medium term notes maturing on July 19, 2023 and November 15, 2041, respectively, and bearing interest at 3.69 and 4.55 per cent per annum, respectively.

  In October 2013, we issued US$625 million of senior notes maturing on October 16, 2023, bearing interest at 3.75 per cent, and US$625 million of senior notes maturing on October 16, 2043, bearing interest at 5.00 per cent.

  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 our capital program and for general corporate purposes.

- In October 2013, we redeemed all four million outstanding 5.60 per cent Cumulative Redeemable First Preferred Shares Series U at a price of $50 per share plus $0.5907 of accrued and unpaid dividends. The total face value of the outstanding Series U Shares was $200 million and they carried an aggregate of $11.2 million in annualized dividends.

Teleconference – Audio and Slide Presentation:

We will hold a teleconference and webcast on Tuesday, November 5, 2013 to discuss our third quarter 2013 financial results. Russ Girling, TransCanada president and chief executive officer and Don Marchand, executive vice-president and chief financial officer, along with other members of the TransCanada executive leadership team, will discuss the financial results and Company developments at 9 a.m. (MST) / 11 a.m. (EST).

Analysts, members of the media and other interested parties are invited to participate by calling 866.226.1792 or 416.340.2216 (Toronto area). Please dial in 10 minutes prior to the start of the call. No pass code is required. A live webcast of the teleconference will be available at **www.transcanada.com**.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (EST) on November 12, 2013. Please call 800.408.3053 or 905.694.9451 and enter pass code 6573719.

The unaudited interim Consolidated Financial Statements and Management's Discussion and Analysis (MD&A) are available 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 68,500 kilometres (42,500 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 400 billion cubic feet of storage capacity. A growing independent power producer, TransCanada owns or has interests in over 11,800 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 November 4, 2013 and 2012 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, 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 November 4, 2013.

- 30 -

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Quarterly report to shareholders

Third quarter 2013

Financial highlights

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

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $, except per share amounts)	**2013**	**2012**	**2013**	**2012**
Income				
Revenue	**2,204**	2,126	**6,465**	5,918
Comparable EBITDA	**1,257**	1,083	**3,568**	3,193
Net income attributable to common shares	**481**	369	**1,292**	993
per common share - basic	**$0.68**	$0.52	**$1.83**	$1.41
Comparable earnings	**447**	349	**1,174**	1,012
per common share	**$0.63**	$0.50	**$1.66**	$1.44
Operating cash flow				
Funds generated from operations	**1,046**	866	**2,917**	2,466
Decrease/(increase) in operating working capital	**72**	235	**(252)**	80
Net cash provided by operations	**1,118**	1,101	**2,665**	2,546
Investing activities				
Capital expenditures	**992**	694	**3,030**	1,555
Equity investments	**30**	144	**101**	557
Acquisitions	**99**	—	**154**	—
Dividends				
Per common share	**$0.46**	$0.44	**$1.38**	$1.32
Basic common shares outstanding (millions)				
Average for the period	**707**	705	**707**	704
End of period	**707**	705	**707**	705

Management's discussion and analysis

November 4, 2013

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TransCanada Corporation. It discusses our business, operations, financial position, risks and other factors for the three and nine months ended September 30, 2013, and should be read with the accompanying unaudited condensed consolidated financial statements for the three and nine months ended September 30, 2013 which have been prepared in accordance with U.S. GAAP.

This MD&A should also be read in conjunction with our December 31, 2012 audited consolidated financial statements and notes and the MD&A in our 2012 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 2012 Annual Report.

All information is as of November 4, 2013 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
- 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
- performance of our counterparties
- 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
- labour, equipment and material costs
- access to capital markets
- interest and foreign exchange rates
- weather
- cybersecurity
- 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 2012 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
- comparable income taxes expense.

These measures 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 entities.

EBITDA and EBIT

We use EBITDA as an approximate measure of our pre-tax operating cash flow. It measures our earnings before deducting interest and other financial charges, income taxes, 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 an effective measure of our performance and an effective tool for evaluating trends in each segment. 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 an effective 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. See 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	EBIT
comparable depreciation and amortization	depreciation and amortization
comparable interest expense	interest expense
comparable interest income and other	interest income and other
comparable income taxes expense	income taxes expense/(recovery)

Our decision not to include a specific item is subjective and made after careful consideration. These may include:

- certain fair value adjustments relating to risk management activities
- income tax refunds and adjustments
- gains or losses on sales of assets
- legal and bankruptcy settlements, and
- write-downs of assets and investments.

In our calculation of comparable earnings, we exclude 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 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.

Reconciliation of non-GAAP measures

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $, except per share amounts)	**2013**	**2012**	**2013**	**2012**
Comparable EBITDA	**1,257**	1,083	**3,568**	3,193
Comparable depreciation and amortization	**(366)**	(342)	**(1,076)**	(1,032)
Comparable EBIT	**891**	741	**2,492**	2,161
Other income statement items				
Comparable interest expense	**(235)**	(249)	**(744)**	(730)
Comparable interest income and other	**16**	22	**32**	66
Comparable income taxes expense	**(172)**	(123)	**(464)**	(354)
Net income attributable to non-controlling interests	**(33)**	(29)	**(87)**	(90)
Preferred share dividends	**(20)**	(13)	**(55)**	(41)
Comparable earnings	**447**	349	**1,174**	1,012
Specific items (net of tax):				
Canadian restructuring proposal - 2012	**—**	—	**84**	—
Part VI.I income tax adjustment	**—**	—	**25**	—
Sundance A PPA arbitration decision - 2011	**—**	—	**—**	(15)
Risk management activities[1]	**34**	20	**9**	(4)
Net income attributable to common shares	**481**	369	**1,292**	993
Comparable depreciation and amortization	**(366)**	(342)	**(1,076)**	(1,032)
Specific item:				
Canadian restructuring proposal - 2012	**—**	—	**(13)**	—
Depreciation and amortization	**(366)**	(342)	**(1,089)**	(1,032)
Comparable interest expense	**(235)**	(249)	**(744)**	(730)
Specific item:				
Canadian restructuring proposal - 2012	**—**	—	**(1)**	—
Interest expense	**(235)**	(249)	**(745)**	(730)
Comparable interest income and other	**16**	22	**32**	66
Specific items:				
Canadian restructuring proposal - 2012	**—**	—	**1**	—
Risk management activities[1]	**15**	12	**—**	4
Interest income and other	**31**	34	**33**	70
Comparable income taxes expense	**(172)**	(123)	**(464)**	(354)
Specific items:				
Canadian restructuring proposal - 2012	**—**	—	**42**	—
Part VI.I income tax adjustment	**—**	—	**25**	—
Income taxes attributable to Sundance A PPA arbitration decision - 2011	**—**	—	**—**	5
Risk management activities[1]	**(18)**	(11)	**(6)**	1
Income taxes expense	**(190)**	(134)	**(403)**	(348)
Comparable earnings per common share	**$0.63**	$0.50	**$1.66**	$1.44
Specific items (net of tax):				
Canadian restructuring proposal - 2012	**—**	—	**0.12**	—
Part VI.I income tax adjustment	**—**	—	**0.04**	—
Sundance A PPA arbitration decision - 2011	**—**	—	**—**	(0.02)
Risk management activities[1]	**0.05**	0.02	**0.01**	(0.01)
Net income per common share	**$0.68**	$0.52	**$1.83**	$1.41

1	(unaudited - millions of $)	three months ended September 30 2013	three months ended September 30 2012	nine months ended September 30 2013	nine months ended September 30 2012
	Canadian Power	**4**	11	**(2)**	10
	U.S. Power	**31**	20	**14**	4
	Natural Gas Storage	**2**	(12)	**3**	(23)
	Foreign exchange	**15**	12	**—**	4
	Income taxes attributable to risk management activities	**(18)**	(11)	**(6)**	1
	Total gains/(losses) from risk management activities	**34**	20	**9**	(4)

EBITDA and EBIT by business segment

three months ended September 30, 2013 (unaudited - millions of $)	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	**684**	**189**	**410**	**(26)**	**1,257**
Comparable depreciation and amortization	**(248)**	**(37)**	**(77)**	**(4)**	**(366)**
Comparable EBIT	**436**	**152**	**333**	**(30)**	**891**

three months ended September 30, 2012 (unaudited - millions of $)	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	660	177	267	(21)	1,083
Comparable depreciation and amortization	(231)	(37)	(70)	(4)	(342)
Comparable EBIT	429	140	197	(25)	741

nine months ended September 30, 2013 (unaudited - millions of $)	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	**2,074**	**554**	**1,017**	**(77)**	**3,568**
Comparable depreciation and amortization	**(733)**	**(111)**	**(220)**	**(12)**	**(1,076)**
Comparable EBIT	**1,341**	**443**	**797**	**(89)**	**2,492**

nine months ended September 30, 2012 (unaudited - millions of $)	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	2,051	526	681	(65)	3,193
Comparable depreciation and amortization	(697)	(109)	(215)	(11)	(1,032)
Comparable EBIT	1,354	417	466	(76)	2,161

Results - Third quarter 2013

Net income attributable to common shares was $481 million this quarter compared to $369 million in third quarter 2012.

Net income attributable to common shares was $1,292 million for the nine months ended September 30, 2013 compared to $993 million for the same period in 2012 . The 2013 results included $84 million of net income related to 2012 from the NEB decision on the Canadian Restructuring Proposal. Also included in net income was a $25 million favourable income tax adjustment due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax. These amounts were excluded from comparable earnings. The 2012 results included an after-tax charge of $15 million ($20 million pre-tax) relating to the Sundance A PPA arbitration decision that was excluded from 2012 comparable earnings as it related to 2011.

Comparable earnings this quarter were $447 million and $0.63 per share, or $98 million and $0.13 per share higher than third quarter 2012.

This was primarily the result of:
- higher equity income from Bruce Power reflecting incremental earnings from Units 1 and 2, which were returned to service in October 2012, and higher incremental earnings from Unit 4 due to the planned life extension outage which began in third quarter 2012 and was completed in April 2013
- higher earnings from Western Power because of lower PPA costs, increased utilization of the Sundance B PPA as well as the return to service of Sundance A Unit 1 in early September 2013
- higher capacity prices in New York and increased generation at the U.S. hydro facilities
- higher earnings from the Canadian Mainline due to the higher ROE of 11.50 per cent in 2013 compared to 8.08 per cent in 2012.

These increases were partly offset by:
- lower contribution from U.S. natural gas pipelines
- higher comparable income taxes because of higher pre-tax earnings.

Comparable earnings for the nine months ended September 30, 2013 were $1,174 million and $1.66 per share, or $162 million and $0.22 per share higher than the same period in 2012.

This was primarily the result of:
- higher equity income from Bruce Power reflecting incremental earnings from Units 1, 2 and 3, partly offset by the impact of the Unit 4 life extension outage which began in August 2012 and was completed in April 2013 and an increase in planned outage days at Bruce B
- higher earnings from U.S. Power because of higher realized power and capacity prices in New York
- higher earnings from Western Power due to higher realized power prices, increased utilization of the Sundance B PPA and lower PPA costs.
- higher earnings from the Canadian Mainline reflecting the higher ROE of 11.50 per cent in 2013 compared to 8.08 per cent in 2012
- higher earnings from the Keystone Pipeline System primarily due to higher contracted volumes.

These increases were partly offset by:
- lower contribution from U.S. natural gas pipelines
- lower comparable interest income and other due to realized losses in 2013 compared to realized gains in 2012 on derivatives used to manage our exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- higher comparable income taxes because of higher pre-tax earnings.

Comparable earnings do not include net unrealized after-tax gains resulting from changes in the fair value of certain risk management activities:
- $34 million ($52 million before tax) for the three months ended September 30, 2013 compared to $20 million ($31 million before tax) for the same period in 2012
- $9 million ($15 million before tax) for the nine months ended September 30, 2013 compared to losses of $4 million (losses of $5 million before tax) for the same period in 2012.

Outlook

While the NEB's March 27, 2013 decision on the Canadian Restructuring Proposal for tolls and services on the Canadian Mainline may result in increased variability and seasonality of cash flow, we expect it to have a positive impact on the earnings outlook for 2013 previously included in our 2012 Annual Report. The NEB approved an allowed ROE of 11.50 per cent on 40 per cent deemed common equity, fixed multi-year firm tolls through 2017 and a new incentive mechanism. In addition, we expect the increase in 2013 power prices in Western Power to also have a positive impact on our previously disclosed earnings outlook for 2013. See the MD&A in our 2012 Annual Report for further information about our outlook.

Natural Gas Pipelines

Comparable EBITDA and comparable EBIT are non-GAAP measures. See non-GAAP measures section for more information.

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2013**	**2012**	**2013**	**2012**
Canadian Pipelines				
Canadian Mainline	**273**	247	**816**	744
NGTL System	**210**	194	**585**	554
Foothills	**29**	29	**86**	90
Other Canadian (TQM[1], Ventures LP)	**7**	7	**20**	22
Canadian Pipelines - comparable EBITDA	**519**	477	**1,507**	1,410
Comparable depreciation and amortization[2]	**(191)**	(179)	**(565)**	(533)
Canadian Pipelines - comparable EBIT	**328**	298	**942**	877
U.S. and International (US$)				
ANR	**33**	41	**155**	191
GTN[3]	**11**	28	**65**	84
Great Lakes[4]	**6**	16	**24**	51
TC PipeLines, LP[1,5]	**21**	19	**51**	57
Other U.S. pipelines (Iroquois[1], Bison[3], Portland[6])	**15**	22	**81**	79
International (Gas Pacifico/INNERGY[1], Guadalajara, Tamazunchale, TransGas[1])	**30**	27	**81**	85
General, administrative and support costs	**(2)**	—	**(7)**	(4)
Non-controlling interests[7]	**52**	39	**126**	122
U.S. Pipelines and International - comparable EBITDA	**166**	192	**576**	665
Comparable depreciation and amortization[2]	**(55)**	(53)	**(164)**	(164)
U.S. Pipelines and International - comparable EBIT	**111**	139	**412**	501
Foreign exchange	**4**	(1)	**8**	1
U.S. Pipelines and International - comparable EBIT (Cdn$)	**115**	138	**420**	502
Business Development comparable EBITDA and EBIT	**(7)**	(7)	**(21)**	(25)
Natural Gas Pipelines - comparable EBIT	**436**	429	**1,341**	1,354

Summary				
Natural Gas Pipelines - comparable EBITDA	**684**	660	**2,074**	2,051
Comparable depreciation and amortization[2]	**(248)**	(231)	**(733)**	(697)
Natural Gas Pipelines - comparable EBIT	**436**	429	**1,341**	1,354

1 Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect our share of equity income from these investments.
2 Does not include depreciation and amortization from equity investments.
3 Effective July 1, 2013, represents our 30 per cent direct ownership interest. Prior to July 1, 2013, our direct ownership interest was 75 per cent.
4 Represents our 53.6 per cent direct ownership interest.
5 Effective May 22, 2013, our ownership interest in TC PipeLines, LP decreased from 33.3 per cent to 28.9 per cent. On July 1, 2013, we sold 45 per cent of GTN and Bison to TC PipeLines, LP. The following shows our ownership interest in TC PipeLines,LP and our effective ownership of GTN, Bison, and Great Lakes through our ownership interest in TC PipeLines, LP for the periods presented.

	Effective Ownership Percentage as of		
	July 1, 2013	**May 22, 2013**	**January 1, 2012**
TC PipeLines, LP	28.9	28.9	33.3
GTN/Bison	20.2	7.2	8.3
Great Lakes	13.4	13.4	15.4

6 Represents our 61.7 per cent ownership interest.
7 Comparable EBITDA for the portions of TC PipeLines, LP and Portland we do not own.

NET INCOME - WHOLLY OWNED CANADIAN PIPELINES

(unaudited - millions of $)	three months ended September 30		nine months ended September 30	
	2013	**2012**	**2013**	**2012**
Canadian Mainline - net income	**67**	47	**285**	140
Canadian Mainline - comparable earnings	**67**	47	**201**	140
NGTL System	**57**	53	**171**	153
Foothills	**4**	4	**13**	14

OPERATING STATISTICS - WHOLLY OWNED PIPELINES

nine months ended September 30, 2013 (unaudited)	Canadian Mainline[1]		NGTL System[2]		ANR[3]	
	2013	**2012**	**2013**	**2012**	**2013**	**2012**
Average investment base (millions of $)	**5,855**	5,748	**5,913**	5,426	**n/a**	n/a
Delivery volumes (Bcf)						
Total	**992**	1,167	**2,658**	2,697	**1,182**	1,199
Average per day	**3.6**	4.3	**9.7**	9.8	**4.3**	4.4

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 nine months ended September 30, 2013 were 547 Bcf (2012 – 659 Bcf). Average per day was 2.0 Bcf (2012 – 2.4 Bcf).
2 Field receipt volumes for the NGTL System for the nine months ended September 30, 2013 were 2,748 Bcf (2012 – 2,747 Bcf). Average per day was 10.1 Bcf (2012 – 10.0 Bcf).
3 Under its current rates, which are approved by the FERC, changes in average investment base do not affect results.

CANADIAN PIPELINES

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

Canadian Mainline's comparable earnings increased by $20 million for the three months ended September 30, 2013 and $61 million for the nine months ended September 30, 2013 compared to the same periods in 2012 because of the impact of the NEB's March 2013 decision (the NEB decision) on the Canadian Restructuring Proposal. Among other items, the NEB approved an ROE of 11.50 per cent on a 40 per cent deemed common equity for the years 2012 through to 2017 compared to the last approved ROE of 8.08 per cent on a deemed common equity of 40 per cent that was used to record earnings in 2012. Net income of $285 million for the nine months ended September 30, 2013 included $84 million related to the 2012 impact of the NEB decision.

Net income for the NGTL System (formerly known as the Alberta System) increased by $4 million for the three months ended September 30, 2013 and $18 million for the nine months ended September 30, 2013 compared to the same periods in 2012 because of a higher average investment base and termination of the annual fixed OM&A costs component included in the 2010 - 2012 Revenue Requirement Settlement which expired at the end of 2012. Results for 2013 reflect the last approved ROE of 9.70 per cent on deemed common equity of 40 per cent and no incentive earnings.

U.S. PIPELINES AND INTERNATIONAL

EBITDA for our U.S. operations is 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 the U.S. and international pipelines was US$166 million for the three months ended September 30, 2013 and US$576 million for the nine months ended September 30, 2013 compared to US$192 million and US$665 million for the same periods in 2012. This was the net effect of:

- lower contributions from GTN and Bison due to the reduction of our direct ownership in each pipeline from 75 per cent to 30 per cent, effective July 1, 2013
- lower revenues at Great Lakes because of lower rates and uncontracted capacity
- higher costs at ANR relating to services provided by other pipelines as well as lower revenues.

COMPARABLE DEPRECIATION AND AMORTIZATION

Comparable depreciation and amortization was $248 million for the three months ended September 30, 2013 and $733 million for the nine months ended September 30, 2013 compared to $231 million and $697 million for the same periods in 2012 mainly because of a higher investment base on the NGTL System and the impact of the NEB decision on the Canadian Mainline.

Oil Pipelines

Comparable EBITDA and comparable EBIT are non-GAAP measures. See non-GAAP measures section for more information.

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2013**	**2012**	**2013**	**2012**
Keystone Pipeline System	**193**	180	**566**	532
Oil Pipelines Business Development	**(4)**	(3)	**(12)**	(6)
Oil Pipelines - comparable EBITDA	**189**	177	**554**	526
Comparable depreciation and amortization	**(37)**	(37)	**(111)**	(109)
Oil Pipelines - comparable EBIT	**152**	140	**443**	417

Comparable EBIT denominated as follows:				
Canadian dollars	**50**	48	**149**	147
U.S. dollars	**98**	92	**287**	269
Foreign exchange	**4**	—	**7**	1
	152	140	**443**	417

Comparable EBITDA from our Keystone Pipeline System is generated primarily by providing pipeline capacity to shippers on a take-or-pay basis in exchange 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 $13 million for the three months ended September 30, 2013 and $34 million for the nine months ended September 30, 2013 compared to the same periods in 2012. These increases reflected higher revenues primarily resulting from:

- higher contracted volumes
- higher final fixed tolls on committed pipeline capacity to Cushing, Oklahoma, which came into effect in July 2012.

BUSINESS DEVELOPMENT

Business development expenses in the first nine months of 2013 were $6 million higher than the same period in 2012 because of increased activity on various oil pipeline development projects.

Energy

Comparable EBITDA and comparable EBIT are non-GAAP measures. See non-GAAP measures section for more information.

(unaudited - millions of $)	three months ended September 30 2013	three months ended September 30 2012	nine months ended September 30 2013	nine months ended September 30 2012
Canadian Power				
Western Power[1]	**118**	93	**320**	251
Eastern Power[1,2]	**78**	85	**248**	251
Bruce Power[1]	**105**	4	**195**	22
General, administrative and support costs	**(11)**	(12)	**(33)**	(34)
Canadian Power - comparable EBITDA	**290**	170	**730**	490
Comparable depreciation and amortization[3]	**(43)**	(38)	**(129)**	(117)
Canadian Power - comparable EBIT	**247**	132	**601**	373
U.S. Power (US$)				
Northeast Power	**122**	100	**291**	195
General, administrative and support costs	**(11)**	(13)	**(33)**	(34)
U.S. Power - comparable EBITDA	**111**	87	**258**	161
Comparable depreciation and amortization	**(29)**	(30)	**(80)**	(90)
U.S. Power - comparable EBIT	**82**	57	**178**	71
Foreign exchange	**3**	(1)	**5**	—
U.S. Power - comparable EBIT (Cdn$)	**85**	56	**183**	71
Natural Gas Storage				
Alberta Storage[1]	**12**	20	**43**	54
General, administrative and support costs	**(3)**	(3)	**(7)**	(7)
Natural Gas Storage - comparable EBITDA	**9**	17	**36**	47
Comparable depreciation and amortization[3]	**(4)**	(2)	**(9)**	(8)
Natural Gas Storage - comparable EBIT	**5**	15	**27**	39
Business Development comparable EBITDA and EBIT	**(4)**	(6)	**(14)**	(17)
Energy - comparable EBIT	**333**	197	**797**	466

Summary				
Energy - comparable EBITDA	**410**	267	**1,017**	681
Comparable depreciation and amortization[3]	**(77)**	(70)	**(220)**	(215)
Energy - comparable EBIT	**333**	197	**797**	466

1 Includes our share of equity income from our investments in ASTC Power Partnership, Portlands Energy, Bruce Power and, in 2012, CrossAlta. In December 2012, we acquired the remaining 40 per cent interest in CrossAlta, bringing our ownership interest to 100 per cent.
2 Includes phase two of Cartier Wind Gros-Morne starting in November 2012 and the acquisition of one Ontario Solar project in June 2013.
3 Does not include depreciation and amortization of equity investments.

Comparable EBITDA for Energy increased by $143 million for the three months ended September 30, 2013 compared to the same period in 2012. The increase was the effect of:

- higher equity income from Bruce Power because of incremental earnings from Units 1 and 2, which were returned to service in October 2012, and higher incremental earnings from Unit 4 due to the planned life extension outage which began in August 2012 and was completed in April 2013
- higher earnings from Western Power mainly because of lower PPA costs, increased utilization of the Sundance B PPA and the return to service of the Sundance A PPA Unit 1 in early September 2013
- higher earnings from U.S. Power mainly because of higher capacity prices in New York and higher generation at the U.S. hydro facilities.

Comparable EBITDA for Energy increased by $336 million for the nine months ended September 30, 2013 compared to the same period in 2012. The increase reflected:

- higher equity income from Bruce Power because of incremental earnings from Units 1 and 2, which were returned to service in October 2012, higher earnings from Unit 3 due to a planned outage during first and second quarter 2012, partially offset by the impact of the Unit 4 life extension planned outage which began in August 2012 and was completed in April 2013 and lower Bruce B volumes due to higher planned outage days
- higher earnings from U.S. Power mainly because of higher realized power and capacity prices in New York
- higher earnings from Western Power mainly because of higher realized power prices, increased utilization of the Sundance B PPA and lower PPA costs.

CANADIAN POWER

Western and Eastern Power[1]

Comparable EBITDA and comparable EBIT are non-GAAP measures. See non-GAAP measures section for more information.

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2013**	**2012**	**2013**	**2012**
Revenue				
Western Power	**138**	152	**441**	482
Eastern Power[1]	**96**	108	**296**	309
Other[2]	**21**	19	**74**	66
	255	279	**811**	857
Income from equity investments[3]	**38**	28	**126**	45
Commodity purchases resold				
Western power	**(38)**	(70)	**(185)**	(207)
Other[4]	**(1)**	(1)	**(4)**	(3)
	(39)	(71)	**(189)**	(210)
Plant operating costs and other	**(58)**	(58)	**(180)**	(160)
Sundance A PPA arbitration decision - 2012	**—**	—	**—**	(30)
General, administrative and support costs	**(11)**	(12)	**(33)**	(34)
Comparable EBITDA	**185**	166	**535**	468
Comparable depreciation and amortization[5]	**(43)**	(38)	**(129)**	(117)
Comparable EBIT	**142**	128	**406**	351

1 Includes phase two of Cartier Wind Gros-Morne starting in November 2012 and the acquisition of one Ontario Solar project in June 2013.
2 Includes sale of excess natural gas purchased for generation and sales of thermal carbon black.
3 Includes our share of equity income from our investments in ASTC Power Partnership, which holds the Sundance B PPA, and Portlands Energy.
4 Includes the cost of excess natural gas not used in operations.
5 Does not include depreciation and amortization of equity investments.

Sales volumes and plant availability

Includes our share of volumes from our equity investments.

(unaudited)	three months ended September 30 2013	three months ended September 30 2012	nine months ended September 30 2013	nine months ended September 30 2012
Sales volumes (GWh)				
Supply				
Generation				
Western Power	**680**	652	**2,037**	1,977
Eastern Power[1]	**872**	1,426	**2,968**	3,476
Purchased				
Sundance A & B and Sheerness PPAs[2]	**1,957**	1,555	**5,452**	4,889
Other purchases	**1**	—	**1**	46
	3,510	3,633	**10,458**	10,388
Sales				
Contracted				
Western Power	**1,846**	2,012	**5,492**	6,048
Eastern Power[1]	**872**	1,426	**2,968**	3,476
Spot				
Western Power	**792**	195	**1,998**	864
	3,510	3,633	**10,458**	10,388
Plant availability[3]				
Western Power[4]	**94%**	91%	**94%**	96%
Eastern Power[1,5]	**94%**	97%	**90%**	89%

1 Includes phase two of Cartier Wind Gros-Morne starting in November 2012 and the acquisition of one Ontario Solar project in June 2013.
2 Includes our 50 per cent ownership interest of Sundance B volumes through the ASTC Power Partnership. Sundance A Unit 1 returned to service in September 2013. Prior to third quarter 2013, no volumes were delivered under the Sundance A PPA in 2012 and 2013.
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 TransCanada under PPAs.
5 Does not include Bécancour because power generation has been suspended since 2008.

Western Power's comparable EBITDA increased by $25 million for the three months ended September 30, 2013 compared to the same period in 2012. The increase was mainly due to lower PPA costs, increased utilization of the Sundance B PPA and the return to service of the Sundance A PPA Unit 1 in early September 2013.

Western Power's comparable EBITDA increased by $69 million for the nine months ended September 30, 2013 compared to the same period 2012. The increase was mainly due to higher realized power prices, increased utilization of the Sundance B PPA and lower PPA costs.

In first quarter 2012, we recorded revenues and costs related to the Sundance A PPA as though the outages of Units 1 and 2 were interruptions of supply in accordance with the terms of the PPA. In July 2012, we received the Sundance A PPA arbitration decision which determined the units were in force majeure in first quarter 2012. In response, we recorded a charge of $30 million in second quarter 2012 equivalent to the pre-tax income we had recorded in first quarter 2012. Sundance A Unit 1 returned to service in early September 2013 and third quarter 2013 revenues and costs included these volumes.

Average spot market power prices in Alberta increased by eight per cent to $84 per MWh for the three months ended September 30, 2013 and 53 per cent to $90 per MWh for the nine months ended September 30, 2013, compared to the same periods in 2012. These increases were mainly the result of plant outages and increased power demand.

Western Power's revenue decreased by $14 million for the three months ended September 30, 2013 compared to the same period in 2012 because of lower purchased volumes under the Sheerness PPA primarily due to higher planned outage days, partially offset by the return to service of Sundance A Unit 1 in early September 2013 and higher generation volumes.

Western Power's revenue decreased by $41 million for the nine months ended September 30, 2013 compared to the same period in 2012 because of the Sundance A PPA revenue recorded in first quarter 2012 partially offset by the return to service of Sundance A Unit 1 in early September 2013 and higher generation volumes.

Western Power's commodity purchases resold decreased by $32 million for the three months ended September 30, 2013 compared to the same period in 2012 because of lower purchased volumes and costs under the Sheerness PPA partially offset by the return to service of Sundance A Unit 1 in September 2013. Western Power's commodity purchases resold decreased by $22 million for the nine months ended September 30, 2013 compared to the same period in 2012 due to the Sundance A PPA costs recorded in first quarter 2012 and lower PPA costs partially offset by the return to service of Sundance A Unit 1 in early September 2013.

Eastern Power's comparable EBITDA and revenue decreased by $7 million and $12 million, respectively, for the three months ended September 30, 2013 compared to the same period in 2012. Eastern Power's comparable EBITDA and revenue decreased by $3 million and $13 million for the nine months ended September 30, 2013 compared to the same period in 2012, respectively. The decreases were mainly due to:

- lower contractual earnings at Bécancour
- lower earnings from Halton Hills
- offset by incremental earnings from Cartier Gros-Morne, which was placed in service in November 2012, and the acquisition of the first Ontario Solar project in June 2013.

Income from equity investments increased by $10 million for the three months ended September 30, 2013 compared to the same period in 2012 due to higher earnings under the Sundance B PPA, because of higher utilization. Income from equity investments increased by $81 million for the nine months ended September 30, 2013 compared to the same period in 2012 because of higher earnings under the Sundance B PPA which reflected higher realized power prices and higher utilization, as well as higher earnings from Portlands Energy which were the result of an unplanned outage in second quarter 2012.

Approximately 70 per cent of Western Power sales volumes were sold under contract this quarter compared to 91 per cent in third quarter 2012. To reduce exposure to spot market prices in Alberta, Western Power enters into fixed price forward sales to secure future revenue and a portion of our power is retained to be sold in the spot market or under shorter-term forward arrangements. The amount sold forward will vary depending on market conditions and market liquidity and has historically ranged between 25 to 75 per cent of expected future production with a higher proportion being hedged in the near term periods. Such forward sales may be completed with medium and large industrial and commercial companies and other market participants and will affect our average realized price (versus spot price) in future periods.

BRUCE POWER

Our proportionate share

(unaudited - millions of $ unless noted otherwise)	three months ended September 30		nine months ended September 30	
	2013	**2012**	**2013**	**2012**
Income/(loss) from equity investments[1]				
Bruce A	**45**	(39)	**132**	(95)
Bruce B	**60**	43	**63**	117
	105	4	**195**	22
Comprised of:				
Revenues	**322**	188	**916**	535
Operating expenses	**(129)**	(142)	**(473)**	(402)
Depreciation and other	**(88)**	(42)	**(248)**	(111)
	105	4	**195**	22
Bruce Power - Other information				
Plant availability[2]				
Bruce A[3]	**81%**	59%	**78%**	55%
Bruce B	**99%**	99%	**85%**	94%
Combined Bruce Power	**91%**	87%	**82%**	76%
Planned outage days				
Bruce A	**—**	60	**123**	213
Bruce B	**—**	—	**140**	46
Unplanned outage days				
Bruce A	**37**	7	**45**	7
Bruce B	**1**	2	**13**	25
Sales volumes (GWh)[1]				
Bruce A[3]	**2,566**	943	**7,127**	2,585
Bruce B	**2,187**	2,241	**5,647**	6,197
	4,753	3,184	**12,774**	8,782
Realized sales price per MWh[4]				
Bruce A	**$71**	$68	**$70**	$68
Bruce B	**$55**	$54	**$54**	$55
Combined Bruce Power	**$62**	$57	**$61**	$57

1 Represents our 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B. Sales volumes exclude deemed generation.
2 The percentage of time the plant was available to generate power, regardless of whether it was running.
3 Plant availability and sales volumes for 2013 include the incremental impact of Units 1 and 2 which were returned to service in October 2012.
4 Calculated 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 $84 million for the three months ended September 30, 2013 compared to the same period in 2012. The increase was mainly due to:

- incremental earnings from Units 1 and 2 which returned to service in October 2012
- higher incremental earnings from Unit 4 due to the planned life extension outage which began in third quarter 2012 and was completed in April 2013.

Equity income from Bruce A increased by $227 million for the nine months ended September 30, 2013 compared to the same period in 2012. The increase was mainly due to:

- incremental earnings from Units 1 and 2 which returned to service in October 2012
- higher earnings from Unit 3 due to the West Shift Plus planned outage during first and second quarter 2012
- recognition in first quarter 2013 of an insurance recovery of approximately $40 million related to the May 2012 Unit 2 electrical generator failure that impacted Bruce A in 2012 and 2013.

The increase for the nine months ended September 30, 2013 was partially offset by the impact of the Unit 4 life extension planned outage which began in August 2012 and was completed in April 2013.

Equity income from Bruce B increased by $17 million for the three months ended September 30, 2013 compared to the same period in 2012. The increase was primarily due to lower lease expense recognized in third quarter 2013 based on the terms of the lease agreement with Ontario Power Generation. A similar lease expense adjustment was recognized in second quarter 2012.

Equity income from Bruce B decreased by $54 million for the nine months ended September 30, 2013 compared to the same period in 2012. The decrease was mainly due to lower volumes and higher operating costs resulting from higher planned outage days.

Under the contract with the OPA, all of the output from Bruce A is sold at a fixed price per MWh. The fixed price is adjusted annually on April 1 for inflation and other provisions under the OPA contract. Bruce A also recovers fuel costs from the OPA.

Bruce A Fixed price	Per MWh
April 1, 2013 - March 31, 2014	$70.99
April 1, 2012 - March 31, 2013	$68.23
April 1, 2011 - March 31, 2012	$66.33

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, 2013 - March 31, 2014	$52.34
April 1, 2012 - March 31, 2013	$51.62
April 1, 2011 - March 31, 2012	$50.18

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. We currently expect 2013 spot prices to be less than the floor price for the year and therefore no amounts received under the floor price mechanism in 2013 are expected to be repaid.

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 overall plant availability percentage in 2013 is expected to be in the mid 80s for Bruce A and the high 80s for Bruce B. No further planned maintenance is scheduled for the remainder of 2013.

U.S. POWER

Comparable EBITDA and comparable EBIT are non-GAAP measures. See non-GAAP measures section for more information.

	three months ended September 30		nine months ended September 30	
(unaudited - millions of US $)	**2013**	**2012**	**2013**	**2012**
Revenue				
Power[1]	**401**	408	**1,151**	836
Capacity	**93**	75	**217**	181
Other[2]	**5**	5	**51**	29
	499	488	**1,419**	1,046
Commodity purchases resold	**(249)**	(268)	**(752)**	(548)
Plant operating costs and other[2]	**(128)**	(120)	**(376)**	(303)
General, administrative and support costs	**(11)**	(13)	**(33)**	(34)
Comparable EBITDA	**111**	87	**258**	161
Comparable depreciation and amortization	**(29)**	(30)	**(80)**	(90)
Comparable EBIT	**82**	57	**178**	71

1 The realized gains and losses from financial derivatives used to buy and sell power, natural gas and fuel oil to manage U.S. Power's assets are presented on a net basis in power revenues.
2 Includes revenues and costs related to a third party service agreement at Ravenswood, the activity level of which increased in 2013.

Sales volumes and plant availability

(unaudited)	three months ended September 30		nine months ended September 30	
	2013	**2012**	**2013**	**2012**
Physical sales volumes (GWh)				
Supply				
Generation	**2,209**	2,350	**5,021**	5,291
Purchased	**2,385**	3,601	**6,742**	6,858
	4,594	5,951	**11,763**	12,149
Plant availability[1]	**94%**	96%	**88%**	86%

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

U.S. Power's comparable EBITDA was US$111 million for the three months ended September 30, 2013 compared to US$87 million for the same period in 2012. The increase was the net effect of:

- higher realized capacity prices in New York
- higher generation at the U.S. hydro facilities
- lower sales volumes to wholesale, commercial and industrial customers
- lower generation at the Ravenswood facility offset by higher realized power and fuel prices.

U.S. Power's comparable EBITDA was US$258 million for the nine months ended September 30, 2013 compared to US$161 million for the same period in 2012. The increase was the net effect of:

- higher realized capacity prices in New York
- higher revenues on sales to wholesale, commercial and industrial customers
- higher realized power prices offset by higher operating costs due to higher fuel prices.

Commodity prices were higher for the three and nine months ended September 30, 2013 compared to the same periods in 2012. In 2013, natural gas prices recovered from low levels in 2012 back to the five year average while gas production levels remained flat. The higher gas prices along with hot weather in July resulted in higher spot power prices in the predominantly gas-fired New England and New York power markets for the nine months ended September 30, 2013.

Physical sales volumes for the three and nine months ended September 30, 2013 were lower than the same periods in 2012 due to lower purchased volumes sold to wholesale, commercial and industrial customers in New England partially offset by increased volumes in our PJM markets. Generation volumes were lower, mainly due to lower generation at our Ravenswood natural gas fueled facility in New York partially offset by higher output at our hydro facilities.

Power revenue of US$401 million for the three months ended September 30, 2013 has decreased compared to US$408 million for the same period in 2012 mainly due to lower sales to wholesale, commercial and industrial customers in New England, offset by higher realized power prices. Power revenue of US$1,151 million for the nine months ended September 30, 2013 increased compared to US$836 million for the same period in 2012 mainly due to higher realized power prices, partially offset by lower volumes.

Capacity revenue was US$93 million for the three months ended September 30, 2013 and US$217 million for the nine months ended September 30, 2013 compared to US$75 million and US$181 million for the same periods in 2012. New York Zone J spot capacity prices were approximately 25 per cent higher than last year on a year to date basis. This increase in spot capacity prices and the impact of hedging activities resulted in higher realized prices in New York, partially offset by lower capacity prices in New England.

Commodity purchases resold were US$249 million for the three months ended September 30, 2013 compared to US$268 million for the same period in 2012. The decrease was due to lower volumes of purchases as sales to wholesale, commercial and industrial customers in New England offset by higher prices to purchase the power to fulfill sales commitments. Commodity purchases resold were US$752 million for the nine months ended September 30, 2013 compared to US$548 million for the same period in 2012 as the increase in prices to fulfill power sales commitments to wholesale, commercial and industrial customers more than offset the lower purchased volumes.

Plant operating costs and other, which includes fuel gas consumed in generation, increased by US$73 million for the nine months ended September 30, 2013 compared to the same period in 2012 because of higher natural gas fuel prices.

As at September 30, 2013, approximately 1,400 GWh or 36 per cent of U.S. Power's planned generation is contracted for the remainder of 2013, and 2,900 GWh or 30 per cent for 2014. 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

Comparable EBITDA and comparable EBIT are non-GAAP measures. See non-GAAP measures section for more information.

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2013**	**2012**	**2013**	**2012**
Alberta Storage[1]	**12**	20	**43**	54
General, administrative and support costs	**(3)**	(3)	**(7)**	(7)
Comparable EBITDA	**9**	17	**36**	47
Comparable depreciation and amortization	**(4)**	(2)	**(9)**	(8)
Comparable EBIT	**5**	15	**27**	39

1 Includes our share of equity income from our investment in CrossAlta up to December 18, 2012. On December 18, 2012, we acquired the remaining 40 per cent interest in CrossAlta, bringing our ownership interest to 100 per cent.

Comparable EBITDA decreased by $8 million for the three months ended September 30, 2013 and $11 million for the nine months ended September 30, 2013 compared to the same periods in 2012 because of lower realized natural gas storage spreads partially offset by incremental earnings from CrossAlta resulting from the acquisition of the remaining 40 per cent interest in December 2012.

Recent developments

NATURAL GAS PIPELINES

Canadian Mainline

On March 27, 2013, the NEB issued its decision on our application to change the business structure and the terms and conditions of service for the Canadian Mainline. Since implementation of the decision on July 1, 2013, an additional 1.3 Bcf/d of firm service originating at Empress has been contracted for, more than doubling the contracted capacity at this location.

Certain additional changes to the Canadian Mainline's tariff were considered as a separate application which was heard in an oral hearing that concluded on September 23, 2013. The changes requested included provisions to diversions and alternate receipt points as well as modifying renewal notification for firm Mainline service. The NEB denied the material changes in its decision issued on October 10, 2013, with reasons to follow.

In September 2013, we reached a settlement with local natural gas distribution companies in Ontario and Québec on long-term tolls that will allow us to provide customers with the flexibility to source gas from various geographic locations within the eastern triangle segment of the system while ensuring that the tolls for the Canadian Mainline are set at levels that recover the costs of providing that flexibility. We expect to file an application for approval of the settlement with the NEB by the end of 2013 that includes a proposed January 1, 2015 implementation date.

NGTL System expansion projects

We continued to expand the NGTL System and have placed approximately $700 million of new facilities in service to date in 2013. We also received NEB approval to construct and operate an additional approximately $300 million of new facilities.

In August 2013, we signed agreements with Progress Energy Canada Ltd. (Progress) for approximately two Bcf/d of firm gas transportation services to underpin the development of a major pipeline extension of the NGTL System. The proposed North Montney 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 LNG export facility near Prince Rupert, B.C. and is expected to cost approximately $1.7 billion, which includes $100 million for downstream facilities. Under the commercial arrangements with Progress, receipt volumes are expected to increase between 2016 and 2019 to an aggregate volume of approximately two Bcf/d and delivery volumes to the PRGT project are expected to be approximately 2.1 Bcf/d beginning in 2019. We are also in discussions with other parties that have expressed interest in obtaining transportation services that would utilize the North Montney facilities. We plan to file an application for approval to construct and operate the North Montney Project in fourth quarter 2013.

Also in fourth quarter 2013, we expect to begin a notification process to potential shippers for a proposal to provide export delivery service to Vanderhoof, B.C. through the use of capacity arrangements on the Coastal GasLink pipeline.

A settlement of the NGTL System annual revenue requirement for the years 2013 and 2014 was reached with shippers and other interested parties in August 2013. The settlement fixes return at 10.1 per cent on a 40 per cent deemed common equity, establishes an increase in the composite depreciation rate to 3.05 per cent and 3.12 per cent for 2013 and 2014, respectively, and fixes the OM&A for 2013 at $190 million and 2014 at $198 million with any variance to our account. In August 2013, we requested and received approval for changes to existing interim rates to reflect the settlement, effective September 1, 2013, pending a decision on the settlement application. On November 1, 2013, the NEB approved the settlement and 2013 final tolls, as filed. Third quarter 2013 results do not reflect the impact of this decision.

Coastal GasLink Pipeline Project

We are currently focused on community, landowner, government and First Nations engagement as the Coastal GasLink pipeline project advances through the regulatory process with the B.C. Environmental Assessment Office and the Canadian Environmental Assessment Agency. We will solicit shipper interest in the provision of delivery service near Vanderhoof, B.C. in fourth quarter 2013.

ANR Lebanon Lateral Reversal Project

Following a successful binding open season which concluded in October 2013, we have executed firm transportation contracts for 350 MMcf/d at maximum tariff rates for 10 years on the ANR Lebanon Lateral Reversal project. The project will require modification to existing facilities at relatively minor capital expenditures, which are expected to be completed in first quarter 2014. Contracted volumes will increase throughout 2014 generating incremental earnings. The project will substantially increase our ability to receive gas on ANR's southeast mainline from the Utica/Marcellus shale plays.

Great Lakes

On September 27, 2013, we filed with FERC a settlement with our customers to modify the transportation rates beginning on November 1, 2013. The settlement is expected to be approved by FERC before the end of the year. The settlement establishes maximum recourse transportation rates on the Great Lakes system. Commencing November 2013, rates will increase, compared to current rates, by approximately 21 percent. This will result in a modest increase in the portion of revenue derived from the recourse rate contracts. The settlement includes a moratorium on filing rate cases or challenging the settlement rates between November 1, 2013 and March 31, 2015 and requires that we file to have new rates in effect no later than January 1, 2018.

Sale of U.S. Pipeline assets to TC PipeLines, LP

In July 2013, we closed the sale of a 45 per cent interest in each of Gas Transmission Northwest LLC (GTN LLC) and Bison Pipeline LLC (Bison LLC) to TC PipeLines, LP for an aggregate purchase price of US$1.05 billion, which included US$146 million representing 45 per cent of GTN's debt, plus normal closing adjustments.

We continue to hold a 30 per cent ownership interest in both pipelines. We also hold a 28.9 per cent interest in TC PipeLines, LP for which we are the General Partner.

Mexican Pipelines

The construction of the Tamazunchale Pipeline Extension project and related compression facilities is proceeding. Although the end of first quarter 2014 continues to be the target in-service date, the construction schedule has been challenged with various issues including the discovery of several archeological finds. The project team continues to monitor and evaluate impacts of related schedule delays. The Topolobampo and Mazatlan projects in northwest Mexico are advancing as planned with engineering and permitting activities.

OIL PIPELINES

Gulf Coast Project

We are constructing a US$2.3 billion 36-inch pipeline from Cushing, Oklahoma to the U.S. Gulf Coast and expect to begin delivering crude oil to Port Arthur, Texas near the end of 2013. Construction is approximately 95 per cent complete.

We have commenced construction of the US$300 million 76 km (47 mile) Houston Lateral pipeline to transport crude oil to Houston, Texas refineries, which is expected to be complete in 2014.

The Gulf Coast Project will have a capacity of up to 700,000 Bbl/d.

Keystone XL Pipeline

On March 1, 2013, the U.S. DOS released its Draft Supplemental Environmental Impact Statement for the Keystone XL Pipeline. The impact statement reaffirmed that construction of the proposed pipeline from the U.S./Canada border in Montana to Steele City, Nebraska would not result in any significant impact to the environment. The DOS continues to review comments on the impact statement that it received during a public comment period that ended on April 22, 2013. Once the DOS has completed its review, it is anticipated it will issue a Final Supplemental Environmental Impact Statement and then consult with other governmental agencies and provide an additional opportunity for public comment during a National Interest Determination period of up to 90 days, before making a decision on our Presidential Permit application.

We anticipate the pipeline to be in service approximately two years following the receipt of the Presidential Permit. The US$5.3 billion cost estimate will increase depending on the timing of the permit. As of September 30, 2013, we have invested US$2.0 billion in the project.

Energy East Pipeline

On August 1, 2013, we announced we are moving forward with the 1.1 million Bbl/d Energy East Pipeline project as it received approximately 900,000 Bbl/d of firm, long-term contracts in its open season to transport crude oil from Western Canada to Eastern refineries and export terminals. The project is estimated to cost approximately $12 billion, excluding the transfer value of Canadian Mainline natural gas assets and, subject to regulatory approvals, is anticipated to be in service by late 2017 for deliveries in Québec and 2018 for deliveries in New Brunswick. We intend to file the necessary regulatory applications for approvals to construct and operate the pipeline project and terminal facilities in the first half of 2014.

Northern Courier Pipeline

In April 2013, we filed a permit application with the Alberta regulator after completing the required Aboriginal and stakeholder engagement and associated field work.

On October 30, 2013, Suncor Energy announced that the Fort Hills Energy Limited Partnership is proceeding with the Fort Hills oil sands mining project and expects to begin producing crude oil as early as late 2017. Our Northern Courier Pipeline project is expected to be completed in 2017 and will transport crude oil from the Fort Hills mine site to Suncor's tank facilities located north of Fort McMurray.

Heartland Pipeline and TC Terminals

In May 2013, we announced we had reached binding long-term shipping agreements to build, own and operate the proposed Heartland Pipeline and TC Terminals projects.

The proposed projects will include a 200 km (125 mile) crude oil pipeline connecting the Edmonton region to facilities in Hardisty, Alberta, and a terminal facility in the Heartland industrial area north of Edmonton. We anticipate the pipeline could transport up to 900,000 Bbl/d, while the terminal is expected to have storage capacity for up to 1.9 million barrels of crude oil. These projects together have a combined cost estimated at $900 million and are expected to come into service during the second half of 2015.

We filed a permit application for the terminal facility with the Alberta regulator in May 2013 and filed an application for the pipeline on October 25, 2013.

Grand Rapids Pipeline

In May 2013, we filed a permit application with the Alberta regulator after completing the required Aboriginal and stakeholder engagement and associated field work.

ENERGY

Ontario Solar

In late 2011, we agreed to buy nine Ontario solar projects (combined capacity of 86 MW) from Canadian Solar Solutions Inc. for approximately $470 million. On June 28, 2013 we completed the acquisition of the first project for $55 million and on September 30, 2013 we completed the acquisition of two additional projects for $99 million. We expect the acquisition of the remaining projects to close between late 2013 and 2014, all subject to satisfactory completion of the related construction activities and regulatory approvals. All power produced will be sold under 20-year PPAs with the OPA.

Sundance A

Sundance A Unit 1 returned to service in early September 2013. Sundance B Unit 2 returned to service in October 2013. TransAlta shut down both units in December 2010 and was ordered by an arbitration panel in July 2012 to rebuild these units.

Bruce Power

On April 5, 2013, Bruce Power announced that it had reached an agreement with the OPA to extend the Bruce B floor price through to the end of the decade which is expected to coincide with the 2019 and 2020 end of life dates for the Bruce B units.

Bruce Power returned Unit 4 to service on April 13, 2013 after completing an expanded life extension outage investment program which began in August 2012. It is anticipated that this investment will allow Unit 4 to operate until at least 2021.

Bruce Power's fully operational eight unit site is now capable of producing more than 6,200 MW towards Ontario's power supply.

Bécancour

In June 2013, Hydro-Québec notified us that it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant through 2014 and the suspension was approved in August 2013. Under the suspension agreement, Hydro-Québec has the option (subject to certain conditions) to extend the suspension every year until regional electricity demand levels recover. We continue to receive capacity payments while generation is suspended.

Other income statement items

(unaudited - millions of $)	three months ended September 30		nine months ended September 30	
	2013	**2012**	**2013**	**2012**
Comparable interest expense	**(235)**	(249)	**(744)**	(730)
Comparable interest income and other	**16**	22	**32**	66
Comparable income taxes expense	**(172)**	(123)	**(464)**	(354)
Net income attributable to non-controlling interests	**(33)**	(29)	**(87)**	(90)

(unaudited - millions of $)	three months ended September 30		nine months ended September 30	
	2013	**2012**	**2013**	**2012**
Comparable interest on long-term debt (including interest on junior subordinated notes)				
Canadian dollar-denominated	**127**	130	**372**	385
U.S. dollar-denominated (US$)	**188**	185	**561**	554
Foreign exchange	**7**	1	**13**	1
	322	316	**946**	940
Other interest and amortization expense	**(7)**	7	**(7)**	14
Capitalized interest	**(80)**	(74)	**(195)**	(224)
Comparable interest expense	**235**	249	**744**	730

Comparable interest expense was $235 million for the three months ended September 30, 2013 compared to $249 million for the same period in 2012 because of the following:

- higher capitalized interest primarily for the Gulf Coast Project and Mexican projects partially offset by the refurbished units at Bruce Power being placed in service
- higher interest expense due to debt issues of US$500 million in July 2013, $750 million in July 2013, US$750 million in January 2013 and US$1.0 billion in August 2012 and higher foreign exchange on interest expense related to U.S. denominated debt partially offset by Canadian and U.S. dollar-denominated debt maturities.

Comparable interest expense was $744 million for the nine months ended September 30, 2013 compared to $730 million for the same period in 2012 because of the following:

- lower capitalized interest as a result of placing the refurbished units at Bruce Power in service, partially offset by higher capitalized interest for the Gulf Coast Project, Mexican projects and Keystone XL
- higher interest expense due to debt issues of US$500 million in July 2013, $750 million in July 2013, US$750 million in January 2013, US$1.0 billion in August 2012 and US$500 million in March 2012 and higher foreign exchange on interest expense related to U.S. denominated debt, partially offset by Canadian and U.S. dollar-denominated debt maturities.

Comparable interest income and other was $32 million for the nine months ended September 30, 2013, compared to $66 million for the same period in 2012 because we had realized losses in 2013 compared to realized gains in 2012 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Comparable income taxes expense were $172 million and $464 million for the three and nine months ended September 30, 2013, respectively, compared to $123 million and $354 million for the same periods in 2012. The increase was mainly the result of higher pre-tax earnings in 2013 compared to 2012 combined with changes in the proportion of income earned between Canadian and foreign jurisdictions.

Financial condition

We strive to maintain financial strength and flexibility in all parts of an economic cycle, and rely on our operating cash flows to sustain our business, pay dividends and fund a portion of our growth.

We access capital markets to meet our financing needs, manage our capital structure and preserve our credit ratings.

We believe we have the capacity to fund our existing capital program through predictable cash flow from our operations, access to the capital markets, cash on hand and substantial committed credit facilities.

CASH FROM OPERATING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2013**	**2012**	**2013**	**2012**
Funds generated from operations[1]	**1,046**	866	**2,917**	2,466
Decrease/(increase) in operating working capital	**72**	235	**(252)**	80
Net cash provided by operations	**1,118**	1,101	**2,665**	2,546

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

Net cash provided by operations was $1,118 million for the three months ended September 30, 2013 and $2,665 million for the nine months ended September 30, 2013 compared to $1,101 million and $2,546 million for the same periods in 2012, respectively, mainly due to an increase in earnings.

At September 30, 2013, our current assets were $2.4 billion and current liabilities were $4.8 billion, leaving us with a working capital deficit of $2.4 billion compared to $3.1 billion at the end of 2012. This working capital deficiency is considered to be in the normal course of business and is managed through our ability to generate cash flow and our ongoing access to the capital markets.

CASH USED IN INVESTING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2013**	**2012**	**2013**	**2012**
Capital expenditures	**992**	694	**3,030**	1,555
Equity investments	**30**	144	**101**	557
Acquisitions	**99**	—	**154**	—

Our capital expenditures this quarter were primarily related to the Gulf Coast Project, expansion of the NGTL System and construction of the Mexican pipelines.

Our cash used in equity investments decreased this quarter and year to date due to lower capital spending at Bruce Power.

On June 28, 2013, we completed the acquisition of the first Ontario Solar project for $55 million. On September 30, 2013, we completed the acquisition of two additional Ontario Solar projects for $99 million.

CASH PROVIDED BY/(USED IN) FINANCING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(unaudited - millions of $)	**2013**	**2012**	**2013**	**2012**
Long-term debt issued, net of issue costs	**2,173**	995	**2,917**	1,488
Long-term debt repaid	**(521)**	(12)	**(1,230)**	(782)
Notes payable repaid, net	**(1,177)**	(930)	**(618)**	(341)
Dividends and distributions paid	**(390)**	(355)	**(1,126)**	(1,057)
Equity financing activities	**4**	17	**1,028**	35

In January 2013, we issued US$750 million of senior notes, maturing on January 15, 2016 and bearing interest at 0.75 per cent per annum.

In March 2013, we completed a public offering of 24 million Series 7 cumulative redeemable first preferred shares at a price of $25 per share for aggregate gross proceeds of $600 million. Investors will be entitled to receive fixed cumulative dividends at an annual rate of $1.00 per share, payable quarterly. Investors will have the right to convert their shares into cumulative redeemable first preferred shares, Series 8, every fifth year beginning on April 30, 2019. The holders of Series 8 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 plus 2.38 per cent.

In June 2013, we retired US$350 million of 4.00 per cent senior notes.

In July 2013, we issued US$500 million of three-year London Interbank Offered Rate-based floating rate notes maturing on June 30, 2016, bearing interest at an initial annual rate of 0.95 per cent.

Also in July 2013, we issued $450 million of ten-year and $300 million of 30-year medium term notes maturing on July 19, 2023 and November 15, 2041, bearing interest at rates of 3.69 and 4.55 per cent per annum, respectively.

In August 2013, we retired US$500 million of 5.05 per cent senior notes.

In October 2013, we issued US$625 million of senior notes, maturing on October 16, 2023 and bearing interest at 3.75 per cent per annum and US$625 million of senior notes, maturing on October 16, 2043 and bearing interest at 5.0 per cent per annum.

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.

Also in October 2013, we redeemed four million outstanding 5.60 per cent Cumulative Redeemable First Preferred Shares Series U. The Series U Shares were redeemed at a price of $50 per share plus $0.5907 of accrued and unpaid dividends. The total face value of the outstanding Series U Shares was $200 million and carried an aggregate of $11.2 million in annualized dividends.

In May 2013, TC PipeLines, LP completed a public offering of 8,855,000 common units at US$43.85 per common unit for gross proceeds of US$388 million. We contributed an additional approximate US$8 million to maintain our general partnership interest and did not purchase any other units. Upon completion of this offering, our ownership interest in TC PipeLines, LP decreased from 33.3 per cent to 28.9 per cent.

In July 2013, TC PipeLines, LP entered into a five-year, US$500 million term loan, maturing July 2018. The proceeds from the public offering, term loan and partner contribution were used to finance the acquisition of the 45 per cent interest in GTN and Bison from us.

DIVIDENDS

On November 4, 2013 we declared quarterly dividends as follows:

Quarterly dividend on our common shares
$0.46 per share (for the quarter ending December 31, 2013)
Payable on January 31, 2014 to shareholders of record at the close of business on December 31, 2013

Quarterly dividends on our preferred shares
Series 1 $0.2875 (for the quarter ending December 31, 2013)
Series 3 $0.25 (for the quarter ending December 31, 2013)
Payable on December 31, 2013 to shareholders of record at the close of business on December 2, 2013
Series 5 $0.275 (for the three month period ending January 30, 2014)
Series 7 $0.25 (for the three month period ending January 30, 2014)
Payable on January 30, 2014 to shareholders of record at the close of business on December 31, 2013

SHARE INFORMATION

October 30, 2013		
Common shares	**Issued and outstanding**	
	707 million	
Preferred shares	**Issued and outstanding**	**Convertible to**
Series 1	22 million	22 million Series 2 preferred shares
Series 3	14 million	14 million Series 4 preferred shares
Series 5	14 million	14 million Series 6 preferred shares
Series 7	24 million	24 million Series 8 preferred shares
Options to buy common shares	**Outstanding**	**Exercisable**
	8 million	4 million

CREDIT FACILITIES

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

At September 30, 2013, we had $5 billion in unsecured credit facilities, including:

Amount	Unused capacity	Subsidiary	For	Matures
$2.0 billion	$2.0 billion	TransCanada PipeLines Limited (TCPL)	Committed, revolving, extendible credit facility that supports TCPL's Canadian commercial paper program	October 2017
US$1.0 billion	US$1.0 billion	TransCanada PipeLine USA Ltd. (TCPL USA)	Committed, revolving, extendible credit facility that supports a TCPL USA U.S. dollar commercial paper program in the U.S.	November 2013
US$1.0 billion	US$1.0 billion	TransCanada Keystone Pipeline, LP	Committed, revolving, extendible credit facility that supports a U.S. dollar commercial paper program in Canada dedicated to funding a portion of Keystone	November 2013
$0.9 billion, US$0.1 billion	$350 million	TCPL, TCPL USA	Demand lines for issuing letters of credit and as a source of additional liquidity. At September 30, 2013, we had outstanding $650 million in letters of credit under these lines	Demand

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

CONTRACTUAL OBLIGATIONS

Our capital commitments have decreased by $436 million primarily due to the completion or advancement of capital projects. Our other purchase commitments decreased by $292 million. There were no other material changes to our contractual obligations in third quarter 2013 or to payments due in the next five years or after. See the MD&A in our 2012 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.

Please see our 2012 Annual Report for more information about the risks we face in our business. In addition to those disclosed risks, in the NEB's March 2013 decision on our Canadian Restructuring Proposal, the NEB found that the fundamental business risk facing the Canadian Mainline has increased. The tolling framework created by the NEB decision results in higher variability in cash flows and greater uncertainty about the ultimate recovery of the Canadian Mainline's cost of service. Otherwise, our risks have not changed substantially since December 31, 2012.

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
- notes, loans and advances receivable.

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At September 30, 2013, we had not incurred any significant credit losses and had no significant amounts past due or impaired. We had a credit risk concentration of $228 million with one counterparty at September 30, 2013 (December 31, 2012 - $259 million). This amount is secured by a guarantee from the counterparty's parent company and we anticipate collecting the full amount.

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 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. operations continue to grow, our exposure to changes in currency rates increases. Some of this risk is offset by interest expense on U.S. dollar-denominated debt and by using foreign exchange derivatives.

We use foreign exchange derivatives to manage other foreign exchange exposures, including those that arise on some of our regulated assets. We defer some of the realized gains and losses on these derivatives as regulatory assets and liabilities until we recover from or pay them to shippers according to the terms of the shipping agreements.

AVERAGE EXCHANGE RATE - U.S. TO CANADIAN DOLLARS

Third quarter 2013	1.03
Third quarter 2012	0.98

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

SIGNIFICANT U.S. DOLLAR-DENOMINATED AMOUNTS

	three months ended September 30		nine months ended September 30	
(unaudited - millions of US$)	2013	2012	2013	2012
U.S. and International Natural Gas Pipelines comparable EBIT	**111**	139	**412**	501
U.S. Oil Pipelines comparable EBIT	**98**	92	**287**	269
U.S. Power comparable EBIT	**82**	57	**178**	71
Interest expense on U.S. dollar-denominated long-term debt	**(188)**	(185)	**(561)**	(554)
Capitalized interest on U.S. capital expenditures	**59**	28	**152**	81
U.S. non-controlling interests and other	**(49)**	(44)	**(136)**	(140)
	113	87	**332**	228

NET INVESTMENT IN FOREIGN OPERATIONS

We hedge our net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, foreign exchange forward contracts and foreign exchange options. The fair values and notional amounts for the derivatives designated as a net investment hedge were as follows:

	September 30, 2013		December 31, 2012	
(unaudited - millions of $)	Fair value[1]	Notional or principal amount	Fair value[1]	Notional or principal amount
Asset/(liability)				
U.S. dollar cross-currency swaps				
(maturing 2013 to 2019)[2]	**(56)**	**US 3,950**	82	US 3,800
U.S. dollar forward foreign exchange contracts				
(maturing 2013 to 2014)	**—**	**US 875**	—	US 250
	(56)	**US 4,825**	82	US 4,050

1 Fair values equal carrying values.
2 Net Income in the three and nine months ended September 30, 2013 included net realized gains of $8 million and $22 million, respectively, (2012 - gains of $8 million and $22 million, respectively) related to the interest component of cross-currency swap settlements.

U.S. DOLLAR-DENOMINATED DEBT DESIGNATED AS A NET INVESTMENT HEDGE

(unaudited - billions of $)	September 30, 2013	December 31, 2012
Carrying value	**12.5 (US 12.2)**	11.1 (US 11.2)
Fair value	**14.5 (US 14.1)**	14.3 (US 14.4)

FAIR VALUE OF DERIVATIVES USED TO HEDGE OUR U.S. DOLLAR INVESTMENT IN FOREIGN OPERATIONS

The classification of the fair value of derivatives to hedge our net investments on the balance sheet.

(unaudited - millions of $)	September 30, 2013	December 31, 2012
Other current assets	**32**	71
Intangible and other assets	**7**	47
Accounts payable and other	**(14)**	(6)
Other long-term liabilities	**(81)**	(30)
	(56)	82

NON-DERIVATIVE FINANCIAL INSTRUMENTS SUMMARY

	September 30, 2013		December 31, 2012	
(unaudited - millions of $)	Carrying amount[1]	Fair value[2]	Carrying amount[1]	Fair value[2]
Financial assets				
Cash and cash equivalents	**645**	**645**	551	551
Accounts receivable and other[3]	**1,127**	**1,176**	1,288	1,337
Available for sale assets	**61**	**61**	44	44
	1,833	**1,882**	1,883	1,932
Financial liabilities[4]				
Notes payable	**1,688**	**1,688**	2,275	2,275
Accounts payable and other long-term liabilities[5]	**1,125**	**1,125**	1,535	1,535
Accrued interest	**330**	**330**	368	368
Long-term debt	**21,037**	**24,720**	18,913	24,573
Junior subordinated notes	**1,028**	**1,054**	994	1,054
	25,208	**28,917**	24,085	29,805

1 Recorded at amortized cost, except for US$200 million (December 31, 2012 - US$350 million) of long-term debt that is attributed to hedged risk and recorded at fair value. This debt, which is recorded at fair value on a recurring basis, is classified in Level II of the fair value hierarchy using the income approach based on interest rates from external data service providers.

2 The fair value measurement of financial assets and liabilities recorded at amortized cost for which the fair value is not equal to the carrying value would be included in Level II of the fair value hierarchy using the income approach based on interest rates from external data service providers.

3 At September 30, 2013, financial assets of $913 million (December 31, 2012 - $1.1 billion) are included in accounts receivable, $41 million (December 31, 2012 - $40 million) in other current assets and $234 million (December 31, 2012 - $240 million) in intangible and other assets.

4 Condensed consolidated statement of income in the three and nine months ended September 30, 2013 included losses of nil and $7 million, respectively, (2012 - losses of $2 million and $14 million, respectively) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$200 million of long-term debt at September 30, 2013 (December 31, 2012 - US$350 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

5 At September 30, 2013, financial liabilities of $1.1 billion (December 31, 2012 - $1.5 billion) are included in accounts payable and $33 million (December 31, 2012 - $38 million) in other long-term liabilities.

DERIVATIVE INSTRUMENTS SUMMARY

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

2013 (unaudited - millions of $ unless noted otherwise)	Power	Natural gas	Foreign exchange	Interest
Derivative instruments held for trading[1]				
Fair values[2]				
Assets	**$140**	**$65**	**$—**	**$9**
Liabilities	**($164)**	**($80)**	**($2)**	**($9)**
Notional values				
Volumes[3]				
Sales	**31,548**	**64**	**—**	**—**
Purchases	**31,705**	**93**	**—**	**—**
Canadian dollars	**—**	**—**	**—**	**462**
U.S. dollars	**—**	**—**	**US 978**	**US 150**
Net unrealized gains/(losses) in the period[4]				
three months ended September 30, 2013	**$18**	**$13**	**$16**	**$—**
nine months ended September 30, 2013	**$15**	**$1**	**($1)**	**$—**
Net realized (losses)/gains in the period[4]				
three months ended September 30, 2013	**($10)**	**($14)**	**$3**	**$—**
nine months ended September 30, 2013	**($46)**	**($21)**	**($5)**	**$—**
Maturity dates	**2013-2017**	**2013-2016**	**2013-2014**	**2013-2016**
Derivative instruments in hedging relationships[5, 6]				
Fair values[2]				
Assets	**$46**	**$—**	**$—**	**$7**
Liabilities	**($42)**	**$—**	**($1)**	**($1)**
Notional values				
Volumes[3]				
Sales	**6,300**	**—**	**—**	**—**
Purchases	**11,264**	**—**	**—**	**—**
U.S. dollars	**—**	**—**	**US 15**	**US 350**
Cross-currency	**—**	**—**	**—**	**—**
Net realized (losses)/gains in the period[4]				
three months ended September 30, 2013	**($18)**	**$—**	**$—**	**$1**
nine months ended September 30, 2013	**($29)**	**($1)**	**$—**	**$5**
Maturity dates	**2013-2018**	**2013**	**2014**	**2015-2018**

1. All derivative instruments held for trading have been entered into for risk management purposes and are subject to our 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 our exposure to market risk.
2. Fair values equal carrying values.
3. Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.
4. 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 revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in interest expense and interest income and other, respectively. The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to revenues, interest expense and interest income and other, as appropriate, as the original hedged item settles.
5. All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $7 million and a notional amount of US$200 million. For the three and nine months ended September 30, 2013, net realized gains on fair value hedges were $1 million and $5 million, respectively, and were included in interest expense. For the three and nine months ended September 30, 2013, we did not record any amounts in net income related to ineffectiveness for fair value hedges.
6. For the three and nine months ended September 30, 2013, 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.

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

2012 (unaudited - millions of $ unless noted otherwise)	Power	Natural gas	Foreign exchange	Interest
Derivative instruments held for trading[1]				
Fair values[2,3]				
Assets	$139	$88	$1	$14
Liabilities	($176)	($104)	($2)	($14)
Notional values[3]				
Volumes[4]				
Sales	31,066	65	—	—
Purchases	31,135	83	—	—
Canadian dollars	—	—	—	620
U.S. dollars	—	—	US 1,408	US 200
Net unrealized gains/(losses) in the period[5]				
three months ended September 30, 2012	$1	$12	$13	$—
nine months ended September 30, 2012	($17)	$2	$5	$—
Net realized gains/(losses) in the period[5]				
three months ended September 30, 2012	$4	($4)	$6	$—
nine months ended September 30, 2012	$8	($19)	$21	$—
Maturity dates	2013 -2017	2013-2016	2013	2013-2016
Derivative instruments in hedging relationships [6,7]				
Fair values[2,3]				
Assets	$76	$—	$—	$10
Liabilities	($97)	($2)	($38)	$—
Notional values[3]				
Volumes[4]				
Sales	7,200	1	—	—
Purchases	15,184	—	—	—
U.S. dollars	—	—	US 12	US 350
Cross-currency	—	—	136/ US 100	—
Net realized (losses)/gains in the period[5]				
three months ended September 30, 2012	($49)	($7)	$—	$2
nine months ended September 30, 2012	($101)	($21)	$—	$5
Maturity dates	2013-2018	2013	2013-2014	2013-2015

1 All derivative instruments held for trading have been entered into for risk management purposes and are subject to our risk management strategies, policies and limits. This includes 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 our exposure to market risk.
2 Fair values equal carrying values.
3 As at December 31, 2012.
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 revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in interest expense and interest income and other, respectively. The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to revenues, interest expense and interest income and other, as appropriate, as the original hedged item settles.
6 All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $10 million and a notional amount of US$350 million. Net realized gains on fair value hedges for the three and nine months ended September 30, 2012 were $2 million and $6 million, respectively, and were included in Interest expense. In the three and nine months ended September 30, 2012, we did not record any amounts in net income related to ineffectiveness for fair value hedges.
7 For the three and nine months ended September 30, 2012, 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.

BALANCE SHEET PRESENTATION OF DERIVATIVE INSTRUMENTS

The fair value of the derivative instruments on the balance sheet.

(unaudited - millions of $)	September 30, 2013	December 31, 2012
Current		
Other current assets	**194**	259
Accounts payable and other	**(208)**	(283)
Long term		
Intangible and other assets	**112**	187
Other long-term liabilities	**(186)**	(186)

DERIVATIVES IN CASH FLOW HEDGING RELATIONSHIPS

The components of other comprehensive income (OCI) related to derivatives in cash flow hedging relationships.

Cash flow hedges[1]	Power		Natural gas		Foreign exchange		Interest	
three months ended September 30 (unaudited - millions of $, pre-tax)	2013	2012	2013	2012	2013	2012	2013	2012
Change in fair value of derivative instruments recognized in OCI (effective portion)	**28**	96	**(1)**	(3)	**1**	(5)	**(1)**	—
Reclassification of gains and losses on derivative instruments from AOCI to net income (effective portion)	**33**	54	**1**	15	**—**	—	**4**	4
Gains and losses on derivative instruments recognized in earnings (ineffective portion)	**6**	5	**—**	1	**—**	—	**—**	—

1 No amounts have been excluded from the assessment of hedge effectiveness.

Cash flow hedges[1]	Power		Natural gas		Foreign exchange		Interest	
nine months ended September 30 (unaudited - millions of $, pre-tax)	2013	2012	2013	2012	2013	2012	2013	2012
Change in fair value of derivative instruments recognized in OCI (effective portion)	**(6)**	74	**(1)**	(17)	**5**	(5)	**(1)**	—
Reclassification of gains and losses on derivative instruments from AOCI to net income (effective portion)	**34**	129	**3**	43	**—**	—	**12**	14
Gains and losses on derivative instruments recognized in earnings (ineffective portion)	**(1)**	6	**—**	—	**—**	—	**—**	—

1 No amounts have been excluded from the assessment of hedge effectiveness.

CREDIT RISK RELATED CONTINGENT FEATURES

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 September 30, 2013, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $18 million (December 31, 2012 - $37 million), with collateral provided in the normal course of business of nil (December 31, 2012 – nil). If the credit-risk-related contingent features in these agreements had been triggered on September 30, 2013, we would have been required to provide collateral of $18 million (December 31, 2012 - $37 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 feel we have sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

FAIR VALUE HIERARCHY

Assets and liabilities that are recorded at fair value are required to be categorized into three levels based on the fair value hierarchy.

Levels	How fair value has been determined
Level I	Quoted prices in active markets for identical assets and liabilities that we have 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.
Level III	Valuation of assets and liabilities measured on a recurring basis using a market approach based on inputs that are unobservable and significant to the overall fair value measurement. This category includes long-dated commodity transactions in certain markets where liquidity is low. Long-term electricity prices are estimated using a third-party modeling tool which takes into account physical operating characteristics of generation facilities in the markets in which we operate. 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 are based 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 is expected to or may result in a lower fair value measurement of contracts included in Level III.

The fair value of our assets and liabilities measured on a recurring basis, including both current and non-current positions.

	Quoted prices in active markets (Level I)[1]		Significant other observable inputs (Level II)[1]		Significant unobservable inputs (Level III)[1]		Total	
(unaudited – millions of $, pre-tax)	**Sep 30, 2013**	**Dec 31, 2012**	**Sep 30, 2013**	**Dec 31, 2012**	**Sep 30, 2013**	**Dec 31, 2012**	**Sep 30, 2013**	**Dec 31, 2012**
Derivative instrument assets:								
Power commodity contracts	**—**	—	**179**	213	**7**	2	**186**	215
Natural gas commodity contracts	**56**	75	**9**	13	**—**	—	**65**	88
Foreign exchange contracts	**—**	—	**39**	119	**—**	—	**39**	119
Interest rate contracts	**—**	—	**16**	24	**—**	—	**16**	24
Derivative instrument liabilities:								
Power commodity contracts	**—**	—	**(198)**	(269)	**(8)**	(4)	**(206)**	(273)
Natural gas commodity contracts	**(71)**	(95)	**(9)**	(11)	**—**	—	**(80)**	(106)
Foreign exchange contracts	**—**	—	**(98)**	(76)	**—**	—	**(98)**	(76)
Interest rate contracts	**—**	—	**(10)**	(14)	**—**	—	**(10)**	(14)
Non-derivative financial instruments:								
Available for sale assets	**—**	—	**61**	44	**—**	—	**61**	44
	(15)	(20)	**(11)**	43	**(1)**	(2)	**(27)**	21

1 There were no transfers from Level I to Level II or from Level II to Level III for the nine months ended September 30, 2013 and 2012.

The following table presents the net change in the Level III fair value category.

	Derivatives[1]			
	three months ended September 30		nine months ended September 30	
(unaudited - millions of $, pre-tax)	2013	2012	2013	2012
Balance at beginning of period	**—**	7	**(2)**	(15)
Settlements	**—**	—	**1**	(1)
Transfers out of Level III	**—**	(12)	**(1)**	(10)
Total gains and losses included in net income	**(1)**	7	**(1)**	8
Total gain and losses included in OCI	**—**	2	**2**	22
Balance at end of period	**(1)**	4	**(1)**	4

1 For the three and nine months ended September 30, 2013, the unrealized gains or losses included in net income attributed to derivatives in the Level III category that were still held at the reporting date was nil (2012 - nil).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $3 million decrease or increase, respectively, in the fair value of outstanding derivative instruments included in Level III at September 30, 2013.

Other information

CONTROLS AND PROCEDURES

Management, including our President and CEO and our CFO, evaluated the effectiveness of our disclosure controls and procedures as at September 30, 2013, as required by the Canadian securities regulatory authorities and by the SEC, and concluded that our disclosure controls and procedures are effective at a reasonable assurance level.

There were no changes in third quarter 2013 that had or are likely to have a material impact on our internal control over financial reporting.

Management continues to implement an Enterprise Resource Planning (ERP) system that will likely affect some processes supporting internal control over financial reporting. The implementation is expected to begin January 1, 2014.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, AND ACCOUNTING 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 judgment. We also regularly assess the assets and liabilities themselves.

Our significant accounting policies and critical accounting estimates have remained unchanged since December 31, 2012 other than described below. You can find a summary of our significant accounting policies and critical accounting estimates in our 2012 Annual Report.

Changes in accounting policies for 2013

Balance sheet offsetting/netting

Effective January 1, 2013, we adopted the ASU on disclosures about balance sheet offsetting as issued by the FASB to enable understanding of the effects of netting arrangements on our financial position. Adoption of the ASU has resulted in increased qualitative and quantitative disclosures about certain derivative instruments that are either offset in accordance with current U.S. GAAP or are subject to a master netting arrangement or similar agreement.

Accumulated other comprehensive income

Effective January 1, 2013, we adopted the ASU on reporting of amounts reclassified out of AOCI as issued by the FASB. Adoption of the ASU has resulted in providing additional qualitative and quantitative disclosures about significant amounts reclassified out of AOCI into net income.

Future accounting changes

Obligations resulting from joint and several liability arrangements

In February 2013, the FASB issued guidance for recognizing, measuring, and disclosing obligations resulting from joint and several liability arrangements when the total amount of the obligation is fixed at the reporting date. Debt arrangements, other contractual obligations, and settled litigation and judicial rulings are examples of these obligations. This ASU is effective retrospectively for fiscal years, and interim reporting periods within those years, beginning after December 15, 2013. We are evaluating the impact that adopting the ASU would have on our consolidated financial statements, but do not expect it to have a material impact.

Foreign currency matters - cumulative translation adjustment

In March 2013, the FASB issued amended guidance related to the release of the cumulative translation adjustment into net income when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets that is a business. This ASU is effective prospectively for fiscal years, and interim reporting periods within those years, beginning after December 15, 2013. Early adoption is allowed as of the beginning of the entity's fiscal year. We are evaluating the impact that adopting this ASU would have on our consolidated financial statements, but do not expect it to have a material impact.

Unrecognized tax benefit

In July 2013, the FASB issued amended guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. This ASU is effective prospectively for fiscal years and interim reporting periods within those years, beginning after December 15, 2014. Early adoption is permitted. We are evaluating the impact that adopting the ASU would have on our consolidated financial statements, but do not expect it to have a material impact.

QUARTERLY RESULTS

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

(unaudited - millions of $, except per share amounts)	2013			2012				2011
	Third	Second	First	Fourth	Third	Second	First	Fourth
Revenues	**2,204**	2,009	2,252	2,089	2,126	1,847	1,945	2,015
Net income attributable to common shares	**481**	365	446	306	369	272	352	376
Share Statistics								
Net Income per common share - basic and diluted	**$0.68**	$0.52	$0.63	$0.43	$0.52	$0.39	$0.50	$0.53
Dividend declared per common share	**$0.46**	$0.46	$0.46	$0.44	$0.44	$0.44	$0.44	$0.42

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 generally remain relatively stable during any fiscal year. Over the long term, however, they fluctuate because of:

- regulators' decisions
- negotiated settlements with shippers
- seasonal fluctuations in short-term throughput volumes on U.S. pipelines
- acquisitions and divestitures
- developments outside of the normal course of operations
- newly constructed assets being placed in service.

In Oil Pipelines, annual revenues and net income are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income during any particular fiscal year remain relatively stable.

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

- weather
- customer demand
- market prices
- 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

Third quarter 2013

- EBIT included net unrealized gains of $52 million pre-tax ($34 million after-tax) from certain risk management activities.

Second quarter 2013

- EBIT included net unrealized losses of $27 million pre-tax ($17 million after-tax) from certain risk management activities.

First quarter 2013

- EBIT included $42 million of pre-tax income ($84 million after-tax) from the NEB Canadian Mainline decision relating to 2012 and net unrealized losses of $10 million pre-tax ($8 million after-tax) from certain risk management activities.

Fourth quarter 2012

- EBIT included net unrealized losses of $17 million pre-tax ($12 million after-tax) from certain risk management activities.

Third quarter 2012

- EBIT included net unrealized gains of $31 million pre-tax ($20 million after-tax) from certain risk management activities.

Second quarter 2012

- EBIT included a $20 million pre-tax charge ($15 million after-tax) related to 2011 from the Sundance A PPA arbitration decision and net unrealized losses of $14 million pre-tax ($13 million after-tax) from certain risk management activities.

First quarter 2012

- EBIT included net unrealized losses of $22 million pre-tax ($11 million after-tax) from certain risk management activities.

Fourth quarter 2011

- EBIT included net unrealized gains of $13 million pre-tax ($11 million after-tax) from certain risk management activities.

Condensed consolidated statement of income

(unaudited - millions of Canadian $ except per share amounts)	three months ended September 30 2013	three months ended September 30 2012	nine months ended September 30 2013	nine months ended September 30 2012
Revenues				
Natural gas pipelines	**1,083**	1,058	**3,271**	3,177
Oil pipelines	**281**	259	**830**	769
Energy	**840**	809	**2,364**	1,972
	2,204	2,126	**6,465**	5,918
Income from Equity Investments	**177**	71	**423**	196
Operating and Other Expenses				
Plant operating costs and other	**650**	627	**1,939**	1,846
Commodity purchases resold	**299**	337	**958**	758
Property taxes	**138**	131	**353**	346
Depreciation and amortization	**366**	342	**1,089**	1,032
	1,453	1,437	**4,339**	3,982
Financial Charges/(Income)				
Interest expense	**235**	249	**745**	730
Interest income and other	**(31)**	(34)	**(33)**	(70)
	204	215	**712**	660
Income before Income Taxes	**724**	545	**1,837**	1,472
Income Taxes (Recovery)/Expense				
Current	**(3)**	6	**40**	101
Deferred	**193**	128	**363**	247
	190	134	**403**	348
Net Income	**534**	411	**1,434**	1,124
Net income attributable to non-controlling interests	**33**	29	**87**	90
Net Income Attributable to Controlling Interests	**501**	382	**1,347**	1,034
Preferred share dividends	**20**	13	**55**	41
Net Income Attributable to Common Shares	**481**	369	**1,292**	993
Net Income per Common Share				
Basic and diluted	**$0.68**	$0.52	**$1.83**	$1.41
Dividends Declared per Common Share	**$0.46**	$0.44	**$1.38**	$1.32
Weighted Average Number of Common Shares (millions)				
Basic	**707**	705	**707**	704
Diluted	**708**	706	**708**	705

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian $)	**2013**	**2012**	**2013**	**2012**
Net Income	**534**	411	**1,434**	1,124
Other Comprehensive (Loss)/Income, Net of Income Taxes				
Foreign currency translation gains and losses on net investments in foreign operations	**(140)**	(196)	**196**	(189)
Change in fair value of net investment hedges	**62**	99	**(122)**	76
Change in fair value of cash flow hedges	**14**	60	**(9)**	43
Reclassification to net income of gains on cash flow hedges	**27**	47	**34**	119
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**1**	—	**1**	—
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**5**	4	**17**	18
Other comprehensive loss on equity investments	**(1)**	(3)	**(4)**	(1)
Other comprehensive (loss)/income (Note 7)	**(32)**	11	**113**	66
Comprehensive Income	**502**	422	**1,547**	1,190
Comprehensive income/(loss) attributable to non-controlling interests	**5**	(5)	**116**	59
Comprehensive Income Attributable to Controlling Interests	**497**	427	**1,431**	1,131
Preferred share dividends	**20**	13	**55**	41
Comprehensive Income Attributable to Common Shares	**477**	414	**1,376**	1,090

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of cash flows

	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian $)	**2013**	**2012**	**2013**	**2012**
Cash Generated from Operations				
Net income	**534**	411	**1,434**	1,124
Depreciation and amortization	**366**	342	**1,089**	1,032
Deferred income taxes	**193**	128	**363**	247
Income from equity investments	**(177)**	(71)	**(423)**	(196)
Distributed earnings received from equity investments	**163**	95	**427**	252
Employee post-retirement benefits funding lower/(higher) than expense	**7**	(23)	**33**	(11)
Other	**(40)**	(16)	**(6)**	18
Decrease/(increase) in operating working capital	**72**	235	**(252)**	80
Net cash provided by operations	**1,118**	1,101	**2,665**	2,546
Investing Activities				
Capital expenditures	**(992)**	(694)	**(3,030)**	(1,555)
Equity investments	**(30)**	(144)	**(101)**	(557)
Acquisitions	**(99)**	—	**(154)**	—
Deferred amounts and other	**(103)**	40	**(267)**	82
Net cash used in investing activities	**(1,224)**	(798)	**(3,552)**	(2,030)
Financing Activities				
Dividends on common and preferred shares	**(346)**	(322)	**(1,012)**	(956)
Distributions paid to non-controlling interests	**(44)**	(33)	**(114)**	(101)
Notes payable repaid, net	**(1,177)**	(930)	**(618)**	(341)
Long-term debt issued, net of issue costs	**2,173**	995	**2,917**	1,488
Repayment of long-term debt	**(521)**	(12)	**(1,230)**	(782)
Common shares issued, net of issue costs	**4**	17	**59**	35
Partnership units of subsidiary issued, net of issue costs	**—**	—	**384**	—
Preferred shares issued, net of issue costs	**—**	—	**585**	—
Net cash provided by/(used in) financing activities	**89**	(285)	**971**	(657)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(12)**	(14)	**10**	(19)
(Decrease)/increase in Cash and Cash Equivalents	**(29)**	4	**94**	(160)
Cash and Cash Equivalents				
Beginning of period	**674**	490	**551**	654
Cash and Cash Equivalents				
End of period	**645**	494	**645**	494

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)	September 30 2013	December 31 2012
ASSETS		
Current Assets		
Cash and cash equivalents	**645**	551
Accounts receivable	**913**	1,052
Inventories	**238**	224
Other	**636**	997
	2,432	2,824
Plant, Property and Equipment, net of accumulated depreciation of $17,598 and $16,540, respectively	**35,985**	33,713
Equity Investments	**5,395**	5,366
Goodwill	**3,575**	3,458
Regulatory Assets	**1,924**	1,629
Intangible and Other Assets	**1,518**	1,343
	50,829	48,333
LIABILITIES		
Current Liabilities		
Notes payable	**1,688**	2,275
Accounts payable and other	**1,771**	2,344
Accrued interest	**330**	368
Current portion of long-term debt	**971**	894
	4,760	5,881
Regulatory Liabilities	**238**	268
Other Long-Term Liabilities	**811**	882
Deferred Income Tax Liabilities	**4,163**	3,953
Long-Term Debt	**20,066**	18,019
Junior Subordinated Notes	**1,028**	994
	31,066	29,997
EQUITY		
Common shares, no par value	**12,136**	12,069
Issued and outstanding: September 30, 2013 - 707 million shares		
December 31, 2012 - 705 million shares		
Preferred shares	**1,813**	1,224
Additional paid-in capital	**406**	379
Retained earnings	**5,001**	4,687
Accumulated other comprehensive loss (Note 7)	**(1,364)**	(1,448)
Controlling Interests	**17,992**	16,911
Non-controlling interests	**1,771**	1,425
	19,763	18,336
	50,829	48,333

Contingencies and Guarantees (Note 11)

Subsequent Events (Note 12)

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of equity

	nine months ended September 30	
(unaudited - millions of Canadian $)	2013	2012
Common Shares		
Balance at beginning of period	**12,069**	12,011
Shares issued on exercise of stock options	**67**	38
Balance at end of period	**12,136**	12,049
Preferred Shares		
Balance at beginning of period	**1,224**	1,224
Shares issued, net of issue costs	**589**	—
Balance at end of period	**1,813**	1,224
Additional Paid-In Capital		
Balance at beginning of period	**379**	380
Exercise of stock options, net of issuances	**(2)**	—
Dilution impact from TC PipeLines, LP units issued	**29**	—
Balance at end of period	**406**	380
Retained Earnings		
Balance at beginning of period	**4,687**	4,628
Net income attributable to controlling interests	**1,347**	1,034
Common share dividends	**(976)**	(930)
Preferred share dividends	**(57)**	(41)
Balance at end of period	**5,001**	4,691
Accumulated Other Comprehensive Loss		
Balance at beginning of period	**(1,448)**	(1,449)
Other comprehensive income	**84**	97
Balance at end of period	**(1,364)**	(1,352)
Equity Attributable to Controlling Interests	**17,992**	16,992
Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	**1,425**	1,465
Net income attributable to non-controlling interests		
TC PipeLines, LP	**63**	70
Preferred share dividends of TCPL	**17**	17
Portland	**7**	3
Other comprehensive income/(loss) attributable to non-controlling interests	**29**	(31)
Sale of TC PipeLines, LP units		
Proceeds, net of issue costs	**384**	—
Decrease in TransCanada's ownership	**(47)**	—
Distributions to non-controlling interests	**(114)**	(101)
Foreign exchange and other	**7**	(4)
Balance at end of period	**1,771**	1,419
Total Equity	**19,763**	18,411

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, 2012. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in TransCanada's 2012 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 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 2012 audited consolidated financial statements included in TransCanada's 2012 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, 2012, except as described in Note 2, Changes in accounting policies.

2. Changes in Accounting Policies

CHANGES IN ACCOUNTING POLICIES FOR 2013

Balance Sheet Offsetting/Netting

Effective January 1, 2013, the Company adopted the ASU on disclosures about balance sheet offsetting as issued by the FASB to enable understanding of the effects of netting arrangements on the Company's financial position. Adoption of the ASU has resulted in increased qualitative and quantitative disclosures regarding certain derivative instruments that are either offset in accordance with current U.S. GAAP or are subject to a master netting arrangement or similar agreement.

Accumulated Other Comprehensive Income

Effective January 1, 2013, the Company adopted the ASU on reporting of amounts reclassified out of AOCI as issued by the FASB. Adoption of the ASU has resulted in providing additional qualitative and quantitative disclosures regarding significant amounts reclassified out of accumulated other comprehensive income into net income.

FUTURE ACCOUNTING CHANGES

Obligations Resulting from Joint and Several Liability Arrangements

In February 2013, the FASB issued guidance for the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. Examples of obligations within the scope of this ASU include debt arrangements, other contractual obligations, and settled litigation and judicial rulings. This ASU is effective retrospectively for fiscal years, and interim reporting periods within those years, beginning after December 15, 2013. The Company is currently evaluating the impact of the adoption of this ASU on its consolidated financial statements, but does not expect it to have a material impact.

Foreign Currency Matters - Cumulative Translation Adjustment

In March 2013, the FASB issued amended guidance related to the release of the cumulative translation adjustment into net income when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets that is a business. This ASU is effective prospectively for fiscal years, and interim reporting periods within those years, beginning after December 15, 2013. Early adoption is permitted as of the beginning of the entity's fiscal year. The Company is currently evaluating the impact of the adoption of this ASU on its consolidated financial statements, but does not expect it to have a material impact.

Unrecognized Tax Benefit

In July 2013, the FASB issued amended guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. This ASU is effective prospectively for fiscal years and interim reporting periods within those years, beginning after December 15, 2014. Early adoption is permitted. We are evaluating the impact that adopting the ASU would have on our consolidated financial statements, but do not expect it to have a material impact.

3. Segmented Information

three months ended September 30	**Natural gas pipelines**		**Oil pipelines**		**Energy**		**Corporate**		**Total**	
(unaudited - millions of Canadian $)	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Revenues	**1,083**	1,058	**281**	259	**840**	809	**—**	—	**2,204**	2,126
Income from equity investments	**36**	37	**—**	—	**141**	34	**—**	—	**177**	71
Plant operating costs and other	**(326)**	(331)	**(81)**	(72)	**(217)**	(203)	**(26)**	(21)	**(650)**	(627)
Commodity purchases resold	**—**	—	**—**	—	**(299)**	(337)	**—**	—	**(299)**	(337)
Property taxes	**(109)**	(104)	**(11)**	(10)	**(18)**	(17)	**—**	—	**(138)**	(131)
Depreciation and amortization	**(248)**	(231)	**(37)**	(37)	**(77)**	(70)	**(4)**	(4)	**(366)**	(342)
	436	429	**152**	140	**370**	216	**(30)**	(25)	**928**	760
Interest expense									**(235)**	(249)
Interest income and other									**31**	34
Income before Income Taxes									**724**	545
Income taxes expense									**(190)**	(134)
Net Income									**534**	411
Net Income Attributable to Non-Controlling Interests									**(33)**	(29)
Net Income Attributable to Controlling Interests									**501**	382
Preferred Share Dividends									**(20)**	(13)
Net Income Attributable to Common Shares									**481**	369

nine months ended September 30 (unaudited - millions of Canadian $)	Natural gas pipelines 2013	Natural gas pipelines 2012	Oil pipelines 2013	Oil pipelines 2012	Energy 2013	Energy 2012	Corporate 2013	Corporate 2012	Total 2013	Total 2012
Revenues	**3,271**	3,177	**830**	769	**2,364**	1,972	**—**	—	**6,465**	5,918
Income from equity investments	**105**	120	**—**	—	**318**	76	**—**	—	**423**	196
Plant operating costs and other	**(983)**	(989)	**(242)**	(209)	**(637)**	(583)	**(77)**	(65)	**(1,939)**	(1,846)
Commodity purchases resold	**—**	—	**—**	—	**(958)**	(758)	**—**	—	**(958)**	(758)
Property taxes	**(264)**	(257)	**(34)**	(34)	**(55)**	(55)	**—**	—	**(353)**	(346)
Depreciation and amortization	**(746)**	(697)	**(111)**	(109)	**(220)**	(215)	**(12)**	(11)	**(1,089)**	(1,032)
	1,383	1,354	**443**	417	**812**	437	**(89)**	(76)	**2,549**	2,132
Interest expense									**(745)**	(730)
Interest income and other									**33**	70
Income before Income Taxes									**1,837**	1,472
Income taxes expense									**(403)**	(348)
Net Income									**1,434**	1,124
Net Income Attributable to Non-Controlling Interests									**(87)**	(90)
Net Income Attributable to Controlling Interests									**1,347**	1,034
Preferred Share Dividends									**(55)**	(41)
Net Income Attributable to Common Shares									**1,292**	993

TOTAL ASSETS

(unaudited - millions of Canadian $)	September 30, 2013	December 31, 2012
Natural Gas Pipelines	**24,206**	23,210
Oil Pipelines	**12,065**	10,485
Energy	**13,116**	13,157
Corporate	**1,442**	1,481
	50,829	48,333

4. Income Taxes

At September 30, 2013, the total unrecognized tax benefit of uncertain tax positions was approximately $24 million (December 31, 2012 - $49 million). TransCanada recognizes interest and penalties related to income tax uncertainties in income tax expense. There is no interest expense or penalties included in net tax expense for the three and nine months ended September 30, 2013 (September 30, 2012 - a reversal of $2 and $1 million, for three and nine months ended of interest expense, respectively, and nil for penalties). At September 30, 2013, the Company had $5 million accrued for interest expense and nil accrued for penalties (December 31, 2012 - $5 million accrued for interest expense and nil for penalties).

The effective tax rates for the nine-month periods ended September 30, 2013 and 2012 were 22 per cent and 23.6 per cent, respectively. The lower effective tax rate in 2013 was a result of the impact of the NEB's decision on the Canadian Restructuring Proposal and the enactment of certain Canadian Federal tax legislation.

TransCanada recognized a favourable income tax adjustment of approximately $25 million due to the enactment of certain Canadian Federal tax legislation in June 2013. Subject to the results of audit examinations by taxing authorities and other legislative amendments, TransCanada does not anticipate further adjustments to the unrecognized tax benefits during the next twelve months that would have a material impact on its financial statements.

5. Long-Term Debt

In the three and nine months ended September 30, 2013, TransCanada capitalized interest related to capital projects of $80 million and $195 million, respectively (September 30, 2012 - $74 million and $224 million, respectively).

In January 2013, TransCanada PipeLines Limited issued US$750 million of 0.75 per cent per annum senior notes due in 2016.

In July 2013, TransCanada PipeLines Limited issued US$500 million of three-year London Interbank Offered Rate-based (LIBOR) floating rate notes maturing in 2016, bearing interest at an initial annual rate of 0.95 per cent.

Also in July 2013, TransCanada PipeLines Limited issued $450 million of ten-year and $300 million of 30-year senior notes maturing in July 2023 and November 2041, bearing interest rates of 3.69 and 4.55 per cent, respectively.

In July 2013, TC PipeLines, LP entered into a five-year, US$500 million term loan maturing in July 2018. Borrowings under the term loan facility bear interest based on LIBOR, or the base rate, plus an applicable margin. The applicable margin for the term loans is based on TC PipeLines, LP's senior debt rating and ranges between 1.125 per cent and 2.00 per cent for LIBOR borrowings and 0.125 per cent and 1.00 per cent for base rate borrowings. The LIBOR based interest rate on TC PipeLines, LP term loan facility averaged 1.44 per cent for the three months ended September 30, 2013.

In June 2013, TransCanada PipeLines Limited retired US$350 million of 4.00 per cent senior notes.

In August 2013, TransCanada PipeLines Limited retired US$500 million of 5.05 per cent senior notes.

6. Equity and Share Capital

On May 22, 2013, TC PipeLines, LP completed a public offering of 8,855,000 common units at a price of $43.85 per unit, resulting in gross proceeds of approximately US$388 million. TransCanada contributed an additional approximate US$8 million to maintain its general partnership interest and did not purchase any other units. Upon completion of this offering, TransCanada's ownership interest in TC PipeLines, LP decreased from 33.3 per cent to 28.9 per cent and an after-tax dilution impact of $29 million ($47 million pre-tax) was recorded in Additional Paid-In Capital.

PREFERRED SHARE ISSUE

In March 2013, TransCanada completed a public offering of 24 million Series 7 cumulative redeemable first preferred shares. The Series 7 preferred shares were issued at $25 per share resulting in gross proceeds of $600 million. The holders of the Series 7 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.00 per share, payable quarterly. The dividend rate will reset on April 30, 2019 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 2.38 per cent. The preferred shares are redeemable by TransCanada on or after April 30, 2019 and on April 30 of every fifth year thereafter at a price of $25 per share plus accrued and unpaid dividends.

The Series 7 preferred shareholders will have the right to convert their shares into Series 8 cumulative redeemable first preferred shares on April 30, 2019 and on April 30 of every fifth year thereafter. The holders of Series 8 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 and 2.38 per cent.

7. Other Comprehensive Income And Accumulated Other Comprehensive Loss

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

three months ended September 30, 2013 (unaudited - millions of Canadian $)	**Before tax amount**	**Income taxes recovery/ (expense)**	**Net of tax amount**
Foreign currency translation gains and losses on net investments in foreign operations	**(104)**	**(36)**	**(140)**
Change in fair value of net investment hedges	**83**	**(21)**	**62**
Change in fair value of cash flow hedges	**27**	**(13)**	**14**
Reclassification to net income of gains and losses on cash flow hedges	**38**	**(11)**	**27**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**2**	**(1)**	**1**
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**9**	**(4)**	**5**
Other comprehensive loss on equity investments	**(1)**	**—**	**(1)**
Other comprehensive income/(loss)	**54**	**(86)**	**(32)**

three months ended September 30, 2012 (unaudited - millions of Canadian $)	Before tax amount	Income taxes recovery/ (expense)	Net of tax amount
Foreign currency translation gains and losses on net investments in foreign operations	(145)	(51)	(196)
Change in fair value of net investment hedges	133	(34)	99
Change in fair value of cash flow hedges	88	(28)	60
Reclassification to net income of gains and losses on cash flow hedges	73	(26)	47
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 on equity investments	(4)	1	(3)
Other comprehensive income	151	(140)	11

nine months ended September 30, 2013 (unaudited - millions of Canadian $)	**Before tax amount**	**Income taxes recovery/ (expense)**	**Net of tax amount**
Foreign currency translation gains and losses on net investments in foreign operations	**144**	**52**	**196**
Change in fair value of net investment hedges	**(165)**	**43**	**(122)**
Change in fair value of cash flow hedges	**(3)**	**(6)**	**(9)**
Reclassification to net income of gains and losses on cash flow hedges	**49**	**(15)**	**34**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**2**	**(1)**	**1**
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**26**	**(9)**	**17**
Other comprehensive loss on equity investments	**(5)**	**1**	**(4)**
Other comprehensive income	**48**	**65**	**113**

nine months ended September 30, 2012 (unaudited - millions of Canadian $)	Before tax amount	Income taxes recovery/ (expense)	Net of tax amount
Foreign currency translation gains and losses on net investments in foreign operations	(141)	(48)	(189)
Change in fair value of net investment hedges	102	(26)	76
Change in fair value of cash flow hedges	52	(9)	43
Reclassification to net income of gains and losses on cash flow hedges	186	(67)	119
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	17	1	18
Other comprehensive loss on equity investments	(1)	—	(1)
Other comprehensive income	215	(149)	66

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

three months ended September 30, 2013 (unaudited - millions of Canadian $)	**Currency translation adjustments**	**Cash flow hedges**	**Pension and OPEB plan adjustments**	**Total[1]**
AOCI Balance at July 1, 2013	**(612)**	**(129)**	**(619)**	**(1,360)**
Other comprehensive (loss)/income before reclassifications[2]	**(50)**	**14**	**—**	**(36)**
Amounts reclassified from accumulated other comprehensive loss	**—**	**27**	**5**	**32**
Net current period other comprehensive (loss)/income	**(50)**	**41**	**5**	**(4)**
AOCI Balance at September 30, 2013	**(662)**	**(88)**	**(614)**	**(1,364)**

1 All amounts are net of tax. Amounts in parentheses indicate losses.
2 Other comprehensive loss before reclassifications on currency translation adjustments is net of non-controlling interest of $28 million.

nine months ended September 30, 2013 (unaudited - millions of Canadian $)	Currency translation adjustments	Cash flow hedges	Pension and OPEB plan adjustments	Total[1]
AOCI Balance at January 1, 2013	**(707)**	**(110)**	**(631)**	**(1,448)**
Other comprehensive income/(loss) before reclassifications[2]	**45**	**(12)**	**—**	**33**
Amounts reclassified from accumulated other comprehensive loss[3]	**—**	**34**	**17**	**51**
Net current period other comprehensive income	**45**	**22**	**17**	**84**
AOCI Balance at September 30, 2013	**(662)**	**(88)**	**(614)**	**(1,364)**

1 All amounts are net of tax. Amounts in parentheses indicate losses.
2 Other comprehensive income before reclassifications on currency translation adjustments is net of non-controlling interest of $29 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 $26 million ($17 million, net of tax) at September 30, 2013. 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 September 30, 2013	nine months ended September 30, 2013	
Cash flow hedges			
Power & Natural Gas	**(34)**	**(37)**	Revenue (Energy)
Interest	**(4)**	**(12)**	Interest expense
	(38)	**(49)**	Total before tax
	11	**15**	Income taxes expense
	(27)	**(34)**	Net of tax
Pension and other post-retirement plan adjustments			
Amortization of actuarial loss and past service cost[2]	**(9)**	**(26)**	Total before tax
	4	**9**	Income taxes expense
	(5)	**(17)**	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 8 for additional detail.

8. 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 September 30				nine months ended September 30			
	Pension benefit plans		Other post-retirement benefit plans		Pension benefit plans		Other post-retirement benefit plans	
(unaudited - millions of Canadian $)	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Service cost	**21**	16	**1**	1	**62**	49	**2**	2
Interest cost	**24**	24	**2**	2	**71**	71	**6**	6
Expected return on plan assets	**(31)**	(28)	**—**	—	**(89)**	(85)	**(1)**	(1)
Amortization of actuarial loss	**8**	5	**1**	—	**23**	14	**2**	1
Amortization of past service cost	**—**	—	**—**	—	**1**	1	**—**	—
Amortization of regulatory asset	**7**	5	**—**	—	**22**	15	**1**	—
Amortization of transitional obligation related to regulated business	**—**	—	**—**	1	**—**	—	**1**	2
Net benefit cost recognized	**29**	22	**4**	4	**90**	65	**11**	10

9. Risk Management and Financial Instruments

COUNTERPARTY CREDIT RISK

TransCanada's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date, without taking into account security held, consisted of accounts receivable, portfolio investments recorded at fair value, the fair value of derivative assets and notes, and loans and advances receivable. The carrying amounts and fair values of these financial assets, except amounts for derivative assets, are included in accounts receivable and other, and available for sale assets in the Non-Derivative Financial Instruments Summary table below. The majority of counterparty credit exposure is with counterparties that are investment grade or the exposure is supported by financial assurances provided by investment grade parties. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At September 30, 2013, there were no significant amounts past due or impaired, and there were no significant credit losses during the period.

At September 30, 2013, the Company had a credit risk concentration of $228 million (December 31, 2012 - $259 million) due from a counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's 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, foreign exchange forward contracts and foreign exchange options.

U.S. DOLLAR-DENOMINATED DEBT DESIGNATED AS A NET INVESTMENT HEDGE

(unaudited - billions of Canadian $)	September 30, 2013	December 31, 2012
Carrying value	**12.5 (US 12.2)**	11.1 (US 11.2)
Fair value	**14.5 (US 14.1)**	14.3 (US 14.4)

FAIR VALUE OF DERIVATIVES USED TO HEDGE OUR U.S. DOLLAR INVESTMENT IN FOREIGN OPERATIONS

(unaudited - millions of Canadian $)	September 30, 2013	December 31, 2012
Other current assets	**32**	71
Intangible and other assets	**7**	47
Accounts payable and other	**(14)**	(6)
Other long-term liabilities	**(81)**	(30)
	(56)	82

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

	September 30, 2013		December 31, 2012	
(unaudited - millions of Canadian $)	Fair Value[1]	Notional or principal amount	Fair value[1]	Notional or principal amount
Asset/(liability)				
U.S. dollar cross-currency swaps				
(maturing 2013 to 2019)[2]	**(56)**	**US 3,950**	82	US 3,800
U.S. dollar forward foreign exchange contracts				
(maturing 2013 to 2014)	**—**	**US 875**	—	US 250
	(56)	**US 4,825**	82	US 4,050

1 Fair values equal carrying values.
2 Net Income in the three and nine months ended September 30, 2013 included net realized gains of $8 million and $22 million, respectively, (2012 - gains of $8 million and $22 million, respectively) related to the interest component of cross-currency swap settlements.

FINANCIAL INSTRUMENTS

Non-Derivative Financial Instruments Summary

The carrying and fair values of non-derivative financial instruments are as follows:

	September 30, 2013		December 31, 2012	
(unaudited - millions of Canadian $)	Carrying amount[1]	Fair value[2]	Carrying amount[1]	Fair value[2]
Financial assets				
Cash and cash equivalents	**645**	**645**	551	551
Accounts receivable and other[3]	**1,127**	**1,176**	1,288	1,337
Available for sale assets	**61**	**61**	44	44
	1,833	**1,882**	1,883	1,932
Financial liabilities[4]				
Notes payable	**1,688**	**1,688**	2,275	2,275
Accounts payable and other long-term liabilities[5]	**1,125**	**1,125**	1,535	1,535
Accrued interest	**330**	**330**	368	368
Long-term debt	**21,037**	**24,720**	18,913	24,573
Junior subordinated notes	**1,028**	**1,054**	994	1,054
	25,208	**28,917**	24,085	29,805

1 Recorded at amortized cost, except for US$200 million (December 31, 2012 - US$350 million) of long-term debt that is attributed to hedged risk and recorded at fair value. This debt, which is recorded at fair value on a recurring basis, is classified in Level II of the fair value hierarchy using the income approach based on interest rates from external data service providers.
2 The fair value measurement of financial assets and liabilities recorded at amortized cost for which the fair value is not equal to the carrying value would be included in Level II of the fair value hierarchy using the income approach based on interest rates from external data service providers.
3 At September 30, 2013, financial assets of $913 million (December 31, 2012 - $1.1 billion) are included in accounts receivable, $41 million (December 31, 2012 - $40 million) in other current assets and $234 million (December 31, 2012 - $240 million) in intangible and other assets.
4 Condensed consolidated statement of income in the three and nine months ended September 30, 2013 included losses of nil and $7 million, respectively, (2012 - losses of $2 million and $14 million, respectively) for fair value adjustments attributable to the hedged interest rate risk associated with interest

rate swap fair value hedging relationships on US$200 million of long-term debt at September 30, 2013 (December 31, 2012 - US$350 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

5 At September 30, 2013, financial liabilities of $1.1 billion (December 31, 2012 - $1.5 billion) are included in accounts payable and $33 million (December 31, 2012 - $38 million) in other long-term liabilities.

Derivative Instruments Summary

Information for the Company's derivative instruments for 2013, excluding hedges of the Company's net investment in foreign operations, is as follows:

(unaudited - millions of Canadian $ unless noted otherwise)	Power	Natural gas	Foreign exchange	Interest
Derivative instruments held for trading[1]				
Fair values[2]				
Assets	**$140**	**$65**	**$—**	**$9**
Liabilities	**($164)**	**($80)**	**($2)**	**($9)**
Notional values				
Volumes[3]				
Sales	**31,548**	**64**	**—**	**—**
Purchases	**31,705**	**93**	**—**	**—**
Canadian dollars	**—**	**—**	**—**	**462**
U.S. dollars	**—**	**—**	**US 978**	**US 150**
Net unrealized gains/(losses) in the period[4]				
three months ended September 30, 2013	**$18**	**$13**	**$16**	**$—**
nine months ended September 30, 2013	**$15**	**$1**	**($1)**	**$—**
Net realized (losses)/gains in the period[4]				
three months ended September 30, 2013	**($10)**	**($14)**	**$3**	**$—**
nine months ended September 30, 2013	**($46)**	**($21)**	**($5)**	**$—**
Maturity dates	**2013-2017**	**2013-2016**	**2013-2014**	**2013-2016**
Derivative instruments in hedging relationships[5,6]				
Fair values[2]				
Assets	**$46**	**$—**	**$—**	**$7**
Liabilities	**($42)**	**$—**	**($1)**	**($1)**
Notional values				
Volumes[3]				
Sales	**6,300**	**—**	**—**	**—**
Purchases	**11,264**	**—**	**—**	**—**
U.S. dollars	**—**	**—**	**US 15**	**US 350**
Cross-currency	**—**	**—**	**—**	**—**
Net realized (losses)/gains in the period[4]				
three months ended September 30, 2013	**($18)**	**$—**	**$—**	**$1**
nine months ended September 30, 2013	**($29)**	**($1)**	**$—**	**$5**
Maturity dates	**2013-2018**	**2013**	**2014**	**2015-2018**

1 All derivative instruments held for trading have been entered into for risk management purposes and 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 Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

4 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 revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in interest expense and interest income and other, respectively. The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to revenues, interest expense and interest income and other, as appropriate, as the original hedged item settles.

5 All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $7 million and a notional amount of US$200 million. For the three and nine months ended September 30, 2013, net realized gains on fair value hedges were $1 million and $5 million, respectively and were included in interest expense. For the three and nine months ended September 30, 2013, the Company did not record any amounts in net income related to ineffectiveness for fair value hedges.

6 For the three and nine months ended September 30, 2013, 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.

Derivative Instruments Summary

Information for the Company's derivative instruments for 2012, excluding hedges of the Company's net investment in foreign operations, is as follows:

(unaudited – millions of Canadian $ unless noted otherwise)	Power	Natural gas	Foreign exchange	Interest
Derivative instruments held for trading[1]				
Fair values[2,3]				
Assets	$139	$88	$1	$14
Liabilities	($176)	($104)	($2)	($14)
Notional values[3]				
Volumes[4]				
Sales	31,066	65	—	—
Purchases	31,135	83	—	—
Canadian dollars	—	—	—	620
U.S. dollars	—	—	US 1,408	US 200
Net unrealized gains/(losses) in the period[5]				
three months ended September 30, 2012	$1	$12	$13	$—
nine months ended September 30, 2012	($17)	$2	$5	$—
Net realized gains/(losses) in the period[5]				
three months ended September 30, 2012	$4	($4)	$6	$—
nine months ended September 30, 2012	$8	($19)	$21	$—
Maturity dates	2013 -2017	2013-2016	2013	2013-2016
Derivative instruments in hedging relationships [6,7]				
Fair values[2,3]				
Assets	$76	$—	$—	$10
Liabilities	($97)	($2)	($38)	$—
Notional values[3]				
Volumes[4]				
Sales	7,200	1	—	—
Purchases	15,184	—	—	—
U.S. dollars	—	—	US 12	US 350
Cross-currency	—	—	136/ US 100	—
Net realized (losses)/gains in the period[5]				
three months ended September 30, 2012	($49)	($7)	$—	$2
nine months ended September 30, 2012	($101)	($21)	$—	$5
Maturity dates	2013-2018	2013	2013-2014	2013-2015

1 All derivative instruments held for trading have been entered into for risk management purposes and 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, 2012.
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 revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in interest expense and interest income and other, respectively. The effective portion of change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to revenues, interest expense and interest income and other, as appropriate, as the original hedged item settles.
6 All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $10 million and a notional amount of US$350 million. Net realized gains on fair value hedges for the three and nine months ended September 30, 2012 were $2 million and $6 million, respectively, and were included in Interest expense. In the three and nine months ended September 30, 2012, the Company did not record any amounts in net income related to ineffectiveness for fair value hedges.
7 For the three and nine months ended September 30, 2012, 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.

BALANCE SHEET PRESENTATION OF DERIVATIVE INSTRUMENTS

The fair value of the derivative instruments in the Company's balance sheet is as follows:

(unaudited - millions of Canadian $)	September 30, 2013	December 31, 2012
Current		
Other current assets	**194**	259
Accounts payable and other	**(208)**	(283)
Long term		
Intangible and other assets	**112**	187
Other long-term liabilities	**(186)**	(186)

DERIVATIVES IN CASH FLOW HEDGING RELATIONSHIPS

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

Cash flow hedges[1]	Power		Natural gas		Foreign exchange		Interest	
three months ended September 30 (unaudited - millions of Canadian $, pre-tax)	2013	2012	2013	2012	2013	2012	2013	2012
Change in fair value of derivative instruments recognized in OCI (effective portion)	**28**	96	**(1)**	(3)	**1**	(5)	**(1)**	—
Reclassification of gains and losses on derivative instruments from AOCI to net income (effective portion)	**33**	54	**1**	15	**—**	—	**4**	4
Gains and losses on derivative instruments recognized in earnings (ineffective portion)	**6**	5	**—**	1	**—**	—	**—**	—

1 No amounts have been excluded from the assessment of hedge effectiveness.

Cash flow hedges[1]	Power		Natural gas		Foreign exchange		Interest	
nine months ended September 30 (unaudited - millions of Canadian $, pre-tax)	2013	2012	2013	2012	2013	2012	2013	2012
Change in fair value of derivative instruments recognized in OCI (effective portion)	**(6)**	74	**(1)**	(17)	**5**	(5)	**(1)**	—
Reclassification of gains and losses on derivative instruments from AOCI to net income (effective portion)	**34**	129	**3**	43	**—**	—	**12**	14
Gains and losses on derivative instruments recognized in earnings (ineffective portion)	**(1)**	6	**—**	—	**—**	—	**—**	—

1 No amounts have been excluded from the assessment of hedge effectiveness.

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 of 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 September 30, 2013 (unaudited - millions of Canadian $)	Gross derivative instruments presented in the balance sheet	Amounts available for offset[1]	Net amounts
Derivative - Asset			
Power	**186**	**(116)**	**70**
Natural gas	**65**	**(61)**	**4**
Foreign exchange	**39**	**(24)**	**15**
Interest	**16**	**(2)**	**14**
Total	**306**	**(203)**	**103**
Derivative - Liability			
Power	**(206)**	**116**	**(90)**
Natural gas	**(80)**	**61**	**(19)**
Foreign exchange	**(98)**	**24**	**(74)**
Interest	**(10)**	**2**	**(8)**
Total	**(394)**	**203**	**(191)**

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 September 30, 2013, the Company had provided cash collateral of $144 million and letters of credit of $30 million to its counterparties. The Company held $1 million in cash collateral and $4 million in letters of credit on asset exposures at September 30, 2013.

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, 2012:

at December 31, 2012 (unaudited - millions of Canadian $)	Gross derivative instruments presented in the balance sheet	Amounts available for offset[1]	Net amounts
Derivative - Asset			
Power	215	(132)	83
Natural gas	88	(83)	5
Foreign exchange	119	(37)	82
Interest	24	(6)	18
Total	446	(258)	188
Derivative - Liability			
Power	(273)	132	(141)
Natural gas	(106)	83	(23)
Foreign exchange	(76)	37	(39)
Interest	(14)	6	(8)
Total	(469)	258	(211)

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 December 31, 2012, the Company had provided cash collateral of $189 million and letters of credit of $45 million to its counterparties. The Company held $2 million in cash collateral and $5 million in letters of credit on asset exposures at December 31, 2012.

CREDIT RISK RELATED CONTINGENT FEATURES

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 September 30, 2013, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $18 million (December 31, 2012 - $37 million), for which the Company had provided collateral in the normal course of business of nil (December 31, 2012 - nil). If the credit-risk-related contingent features in these agreements were triggered on September 30, 2013, the Company would have been required to provide collateral of $18 million (December 31, 2012 - $37 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 feels it 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 assets and liabilities recorded at fair value have been classified into three categories based on the 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 measured on a recurring basis using a market approach based on inputs that are unobservable and significant to the overall fair value measurement. This category includes long-dated commodity transactions in certain markets where liquidity is low. Long-term electricity prices are estimated using a third-party modeling tool which takes into account physical operating characteristics of generation facilities in the markets in which we operate. 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 are based 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 is 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 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:

	Quoted prices in active markets (Level I)[1]		Significant other observable inputs (Level II)[1]		Significant unobservable inputs (Level III)[1]		Total	
(unaudited - millions of Canadian $, pre-tax)	Sep 30, 2013	Dec 31, 2012	Sep 30, 2013	Dec 31, 2012	Sep 30, 2013	Dec 31, 2012	Sep 30, 2013	Dec 31, 2012
Derivative instrument assets:								
Power commodity contracts	**—**	—	**179**	213	**7**	2	**186**	215
Natural gas commodity contracts	**56**	75	**9**	13	**—**	—	**65**	88
Foreign exchange contracts	**—**	—	**39**	119	**—**	—	**39**	119
Interest rate contracts	**—**	—	**16**	24	**—**	—	**16**	24
Derivative instrument liabilities:								
Power commodity contracts	**—**	—	**(198)**	(269)	**(8)**	(4)	**(206)**	(273)
Natural gas commodity contracts	**(71)**	(95)	**(9)**	(11)	**—**	—	**(80)**	(106)
Foreign exchange contracts	**—**	—	**(98)**	(76)	**—**	—	**(98)**	(76)
Interest rate contracts	**—**	—	**(10)**	(14)	**—**	—	**(10)**	(14)
Non-derivative financial instruments:								
Available for sale assets	**—**	—	**61**	44	**—**	—	**61**	44
	(15)	(20)	**(11)**	43	**(1)**	(2)	**(27)**	21

1 There were no transfers from Level I to Level II or from Level II to Level III for the nine months ended September 30, 2013 and 2012.

The following table presents the net change in the Level III fair value category:

	Derivatives[1]			
	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian $, pre-tax)	2013	2012	2013	2012
Balance at beginning of period	**—**	7	**(2)**	(15)
Settlements	**—**	—	**1**	(1)
Transfers out of Level III	**—**	(12)	**(1)**	(10)
Total gains and losses included in Net Income	**(1)**	7	**(1)**	8
Total gains and losses included in OCI	**—**	2	**2**	22
Balance at end of period	**(1)**	4	**(1)**	4

1 For the three and nine months ended September 30, 2013 the unrealized gains or losses included in net income attributed to derivatives in the level III category that were still held at the reporting date was nil (2012 - nil).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $3 million decrease or increase, respectively, in the fair value of outstanding derivative instruments included in Level III as at September 30, 2013.

10. Acquisitions and Disposition

On June 28, 2013, TransCanada acquired the first of nine Ontario solar power facilities from Canadian Solar Solutions Inc. for $55 million.

On September 30, 2013, TransCanada completed the acquisition of two additional Ontario solar power facilities from Canadian Solar Solutions Inc. for $99 million.

TransCanada measured the assets and liabilities acquired at fair value with substantially all of the purchase price allocated to Plant, Property and Equipment. The combined capacity of the nine projects is 86 MW and the cost of the portfolio will be approximately $470 million. TransCanada anticipates the remaining projects will come into service and be acquired by the end of 2014. The renewable energy produced from these projects will be sold to the Ontario Power Authority under a series of 20-year PPAs.

On July 1, 2013, TransCanada completed the sale of a 45 per cent interest in each of Gas Transmission Northwest LLC (GTN LLC) and Bison Pipeline LLC (Bison LLC) to TC PipeLines, LP for an aggregate purchase price of US$1.05 billion, which included US$146 million of long-term debt for 45 per cent of GTN LLC debt outstanding plus normal closing adjustments. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively.

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.

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. With respect to 2013, TransCanada currently expects spot prices to be less than the floor price for the year, therefore no amounts received under the floor price mechanism in the first nine months of 2013 are expected to be repaid.

GUARANTEES

TransCanada and its joint venture partners on Bruce Power, Cameco Corporation and BPC Generation Infrastructure Trust (BPC), have each severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, a lease agreement and contractor 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 redelivery 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 September 30, 2013 (unaudited - millions of Canadian $)	**Term**	**Potential Exposure[1]**	**Carrying Value**
Bruce Power	ranging to 2019[2]	665	9
Other jointly owned entities	ranging to 2040	41	8
		706	17

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

12. Subsequent Events

In October 2013, TransCanada PipeLines Limited issued US$625 million of senior notes, maturing on October 16, 2023 and bearing interest at 3.75 per cent per annum and US$625 million of senior notes, maturing on October 16, 2043 and bearing interest at 5.0 per cent per annum.

Also in October 2013, TransCanada PipeLines Limited redeemed all of the four million outstanding 5.60 per cent Cumulative Redeemable First Preferred Shares Series U. The Series U Shares were redeemed at a price of $50 per share plus $0.5907 representing accrued and unpaid dividends to the redemption date.