**Quarterly**Report to Shareholders

# TransCanada Reports Increase in Second Quarter Results,

## Comparable Earnings to $357 Million or $0.51 Per Share Funds Generated from Operations of $955 Million

CALGARY, Alberta – **July 26, 2013** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced comparable earnings for second quarter 2013 of $357 million or $0.51 per share, compared to $300 million or $0.43 per share for the same period in 2012. Net income attributable to common shares for second quarter 2013 was $365 million or $0.52 per share. TransCanada's Board of Directors also declared a quarterly dividend of $0.46 per common share for the quarter ending September 30, 2013, equivalent to $1.84 per common share on an annualized basis.

"All three of our business segments generated strong results during the second quarter," said Russ Girling, TransCanada's president and chief executive officer. "Higher power prices in Alberta, an increase in capacity prices in New York, the return to an eight unit site at Bruce Power and a higher Canadian Mainline allowed return on equity all contributed to a significant increase in earnings when compared to the same period last year. We were also pleased by the significant shipper interest in our Energy East Pipeline project, which would transport crude oil from western Canada to eastern Canadian markets and add to our existing $26 billion portfolio of commercially secured projects that are targeted for completion by the end of the decade."

Over the next three years, subject to required approvals, we expect to complete $13 billion of projects that are currently in advanced stages of development. They include the Gulf Coast Project, Keystone XL, the Keystone Hardisty Terminal, the initial phase of the Grand Rapids Pipeline, the Heartland Pipeline and TC Terminals projects, the Tamazunchale Pipeline Extension, the acquisition of nine Ontario Solar projects and ongoing expansion of the NGTL System.

We have also commercially secured an additional $13 billion of long-life, contracted energy infrastructure projects that are expected to be placed into service in 2016 and beyond. They include the Coastal GasLink and Prince Rupert Gas Transmission projects that would move natural gas to Canada's West Coast for liquefaction and shipment to Asian markets, the Topolobampo and Mazatlan Gas Pipeline projects in Mexico, completion of the Grand Rapids and Northern Courier oil pipeline projects in Northern Alberta, and the Napanee Generating Station in Eastern Ontario. TransCanada expects these projects to generate predictable, sustained earnings and cash flow.

### Highlights

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

- Second quarter financial results
  - Net income attributable to common shares of $365 million or $0.52 per share
  - Comparable earnings of $357 million or $0.51 per share
  - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.1 billion
  - Funds generated from operations of $955 million
- Declared a quarterly dividend of $0.46 per common share for the quarter ending September 30
- Construction on the US$2.3 billion Gulf Coast Project, excluding the Houston Lateral, is now 85 per cent complete
- Comment period on the U.S. Department of State (DOS) Draft Supplemental Environmental Impact Statement for the Keystone XL Pipeline closed on April 22
- Concluded Energy East open season to obtain firm commitments for a pipeline to transport crude oil from western receipt points to eastern Canadian markets
- For the first time in two decades, Bruce Power is operating as an eight unit site with the return of Unit 4 on April 13 and the recent restart of Units 1 and 2
- Acquired the first of nine Ontario Solar projects for $55 million on June 28
- Sold a 45 per cent interest in each of GTN and Bison to TC PipeLines, LP for US$1.05 billion on July 2

Comparable earnings for second quarter 2013 were $357 million or $0.51 per share compared to $300 million or $0.43 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 second quarter 2013 was $365 million or $0.52 per share compared to $272 million or $0.39 per share in second quarter 2012.

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

**Oil Pipelines:**

- *Gulf Coast Project*: We are constructing a 36-inch pipeline from Cushing, Oklahoma to the U.S. Gulf Coast and expect to begin delivering crude oil to Port Arthur, Texas at the end of 2013. Construction is approximately 85 per cent complete and we estimate the cost of the Cushing to Port Arthur facilities to be US$2.3 billion.

  Construction of the 76 kilometre (km) (47 mile) Houston Lateral pipeline to transport crude oil to Houston refineries is expected to be complete in 2014 at a cost of US$300 million.

  The Gulf Coast Project will have a capacity of up to 700,000 barrels per day (bbl/d).

- *Keystone XL:* On March 1, 2013, the 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 submissions 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 government agencies and provide an additional opportunity for the public to 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 June 30, 2013, we had invested US$1.9 billion in the project.

- *Energy East Pipeline:* On June 17, 2013, we concluded an open season to obtain firm commitments for a pipeline to transport up to 850,000 bbl/d of crude oil from western receipt points to eastern Canadian markets and are currently reviewing the results.

  The Energy East Pipeline project involves converting natural gas pipeline capacity in approximately 3,000 km (1,870 miles) of our existing Canadian Mainline to crude oil service and constructing up to approximately 1,400 km (870 miles) of new pipeline.

  We have begun Aboriginal and stakeholder engagement and associated field work as part of our initial design and planning. If we determine that there is sufficient commercial support for the project, we will apply for regulatory approval to build and operate the facilities, with a potential in-service date of late 2017.

- *Heartland Pipeline and TC Terminals*: On May 2, 2013, we announced we had secured 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.

  On May 30, 2013, we filed a permit application for the terminal facility with the Alberta Energy Regulator and we expect to file an application for the pipeline later in 2013.

- *Northern Courier Pipeline:* On April 25, 2013, we filed a permit application with the Alberta Energy Regulator after completing the required Aboriginal and stakeholder engagement and associated field work. We continue to work with the Fort Hills Energy Limited Partnership on the development of this project.

- *Grand Rapids Pipeline:* On May 23, 2013, we filed a permit application with the Alberta Energy Regulator after completing the required Aboriginal and stakeholder engagement and associated field work. The Grand Rapids Pipeline system will be the first pipeline to connect the growing oil sands region west of the Athabasca River to the Edmonton/Heartland region and will be capable of moving up to 900,000 bbl/d of crude oil and 330,000 bbl/d of diluent.

**Natural Gas Pipelines:**

- *National Energy Board (NEB) decision on the Canadian Restructuring Proposal:* 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. The decision significantly alters the regulatory framework that has formed the basis for more than $10 billion of regulated pipeline investment over the last sixty years.

  On May 1, 2013, we filed an application for a review and variance of the decision and order. The NEB dismissed the review and variance application on June 11, 2013, and released its reasons for dismissal on July 22, 2013. The NEB did, however, recognize that certain changes proposed by TransCanada to the Canadian Mainline's tariff should be considered as a separate application through an oral hearing process that will commence on September 3, 2013.

  We are effectively operating under the new framework set out by the NEB in its decision as of July 1. We have submitted the tariff change application and will manage that process through the oral hearing and await a decision on those changes.

- *NGTL System:* We continue to expand the NGTL System and have placed $700 million of new facilities into service in 2013. We have applied and received approval from the NEB for an additional $130 million of new facilities. To date in 2013, we have applied for an additional $145 million of facilities, which remain subject to NEB approval, and are planning regulatory applications for further expansion into British Columbia (B.C.), which we estimate will cost between $1.0 billion and $1.5 billion, to connect and transport new gas supply that will be delivered to the Prince Rupert Gas Transmission Project as well as other markets served by the NGTL System. In third quarter 2013, we expect to begin an open season to provide delivery service through a transportation by others arrangement on Coastal GasLink to Vanderhoof, B.C.

- *Prince Rupert Gas Transmission Project:* The B.C. Environmental Assessment Office issued its Section 10 Order in June 2013 indicating that the project is reviewable and requires an environmental assessment certificate. The Canadian Environmental Assessment Agency (CEAA) initiated the public comment period with respect to the project in June 2013.

- *Coastal GasLink:* We are currently focused on community, landowner, government and First Nations engagement as the project advances through the regulatory process with the B.C. Environmental Assessment Office and the CEAA.

**Energy:**

- *Bruce Power:* Bruce Power returned Unit 4 to service on April 13, 2013 after completing an expanded life extension outage program which began in August 2012. It is anticipated that this investment will allow Unit 4 to operate until at least 2021. With the return of Unit 4 and the restart of Units 1 and 2, Bruce Power is now operating an eight unit site for the first time in two decades and is capable of generating 6,200 megawatts (MW) of emission-free electricity. No further maintenance outages are planned at Bruce Power for the remainder of 2013.

- *Sundance A:* TransAlta previously announced that it expected Sundance A Units 1 and 2 to be returned to service in the fall of 2013. They subsequently reported an earlier return to service for Unit 1 on July 31, 2013. TransAlta has not announced any change in the return to service date for Unit 2. Combined, Units 1 and 2 are capable of generating 560 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 acquired the first project for $55 million which has a capacity of 10 MW. We expect to close the acquisition of the remaining projects in 2013 and 2014, 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.

- *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. 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.

**Corporate:**

- Our Board of Directors declared a quarterly dividend of $0.46 per share for the quarter ending September 30, 2013 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $1.84 per common share on an annual basis.

- On July 2, 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. The proceeds from the sale will contribute to funding a portion of our capital program. The transaction demonstrates one of the many financing options available to us as we execute on our unprecedented growth portfolio.

  In May 2013, TC PipeLines, LP completed a public offering of 8,855,000 common units at a price of US$43.85 per unit, resulting in gross proceeds of approximately US$388 million. We invested US$8 million to maintain our two per cent general partnership interest and did not purchase any additional common 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 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.

  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.

**Teleconference – Audio and Slide Presentation:**

We will hold a teleconference and webcast on Friday, July 26, 2013 to discuss our second 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 9:00 a.m. (MDT) / 11:00 a.m. (EDT).

Analysts, members of the media and other interested parties are invited to participate by calling 866.507.1212 or 416.695.6616 (Toronto area). Please dial in 10 minutes prior to the start of the call. No pass code is required. A live webcast of the teleconference will be available at www.transcanada.com.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (EDT) on August 2, 2013. Please call 800.408.3053 or 905.694.9451 and enter pass code 1924325.

**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 July 25, 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 July 25, 2013.



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# Quarterly report to shareholders
# Second 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 June 30 | | six months ended June 30 | |
|---|---|---|---|---|
| (unaudited - millions of $, except per share amounts) | **2013** | **2012** | **2013** | **2012** |
| **Income** | | | | |
| Revenue | **2,009** | 1,847 | **4,261** | 3,792 |
| Comparable EBITDA | **1,143** | 997 | **2,311** | 2,110 |
| Net income attributable to common shares | **365** | 272 | **811** | 624 |
| per common share - basic | **$0.52** | $0.39 | **$1.15** | $0.89 |
| Comparable earnings | **357** | 300 | **727** | 663 |
| per common share | **$0.51** | $0.43 | **$1.03** | $0.94 |
| **Operating cash flow** | | | | |
| Funds generated from operations | **955** | 729 | **1,871** | 1,600 |
| (Increase)/decrease in operating working capital | **(114)** | 14 | **(324)** | (155) |
| **Net cash provided by operations** | **841** | 743 | **1,547** | 1,445 |
| **Investing activities** | | | | |
| Capital expenditures | **1,109** | 397 | **2,038** | 861 |
| Equity investments | **39** | 197 | **71** | 413 |
| Acquisition | **55** | - | **55** | - |
| **Dividends** | | | | |
| Per common share | **$0.46** | $0.44 | **$0.92** | $0.88 |
| **Basic common shares outstanding (millions)** | | | | |
| Average for the period | **707** | 704 | **706** | 704 |
| End of period | **707** | 704 | **707** | 704 |

# Management's discussion and analysis

July 25, 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 six months ended June 30, 2013, and should be read with the accompanying unaudited condensed consolidated financial statements for the three and six months ended June 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 July 25, 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 required as a result 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 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
- 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
- funds generated from operations.

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 cashflow 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 | income tax 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 June 30 | | six months ended June 30 | |
|---|---|---|---|---|
| (unaudited - millions of $, except per share amounts) | **2013** | **2012** | **2013** | **2012** |
| **Comparable EBITDA** | **1,143** | 997 | **2,311** | 2,110 |
| Comparable depreciation and amortization | **(356)** | (346) | **(710)** | (690) |
| **Comparable EBIT** | **787** | 651 | **1,601** | 1,420 |
| **Other income statement items** | | | | |
| Comparable interest expense | **(252)** | (239) | **(509)** | (481) |
| Comparable interest income and other | **(2)** | 19 | **16** | 44 |
| Comparable income taxes | **(133)** | (91) | **(292)** | (231) |
| Net income attributable to non-controlling interests | **(23)** | (26) | **(54)** | (61) |
| Preferred share dividends | **(20)** | (14) | **(35)** | (28) |
| **Comparable earnings** | **357** | 300 | **727** | 663 |
| Specific items (net of tax): | | | | |
| Canadian restructuring proposal - 2012 | **-** | - | **84** | - |
| Income tax adjustment | **25** | - | **25** | - |
| Sundance A PPA arbitration decision - 2011 | **-** | (15) | **-** | (15) |
| Risk management activities[1] | **(17)** | (13) | **(25)** | (24) |
| **Net income attributable to common shares** | **365** | 272 | **811** | 624 |
| **Comparable depreciation and amortization** | **(356)** | (346) | **(710)** | (690) |
| Specific item: | | | | |
| Canadian restructuring proposal - 2012 | **-** | - | **(13)** | - |
| **Depreciation and amortization** | **(356)** | (346) | **(723)** | (690) |
| **Comparable interest expense** | **(252)** | (239) | **(509)** | (481) |
| Specific item: | | | | |
| Canadian restructuring proposal - 2012 | **-** | - | **(1)** | - |
| **Interest expense** | **(252)** | (239) | **(510)** | (481) |
| **Comparable interest income and other** | **(2)** | 19 | **16** | 44 |
| Specific items: | | | | |
| Canadian restructuring proposal - 2012 | **-** | - | **1** | - |
| Risk management activities[1] | **(9)** | (14) | **(15)** | (8) |
| **Interest income and other** | **(11)** | 5 | **2** | 36 |
| **Comparable income taxes** | **(133)** | (91) | **(292)** | (231) |
| Specific items: | | | | |
| Canadian restructuring proposal - 2012 | **-** | - | **42** | - |
| Income tax adjustment | **25** | - | **25** | - |
| Income taxes attributable to Sundance A PPA arbitration decision - 2011 | **-** | 5 | **-** | 5 |
| Risk management activities[1] | **10** | 1 | **12** | 12 |
| **Income taxes expense** | **(98)** | (85) | **(213)** | (214) |
| **Comparable earnings per common share** | **$0.51** | $0.43 | **$1.03** | $0.94 |
| Specific items (net of tax): | | | | |
| Canadian restructuring proposal - 2012 | **-** | - | **0.12** | - |
| Income tax adjustment | **0.04** | - | **0.04** | - |
| Sundance A PPA arbitration decision - 2011 | **-** | (0.02) | **-** | (0.02) |
| Risk management activities[1] | **(0.03)** | (0.02) | **(0.04)** | (0.03) |
| **Net income per common share** | **$0.52** | $0.39 | **$1.15** | $0.89 |

| [1] (unaudited - millions of $) | three months ended June 30 2013 | three months ended June 30 2012 | six months ended June 30 2013 | six months ended June 30 2012 |
|---|---|---|---|---|
| Canadian Power | **(4)** | 1 | **(6)** | (1) |
| U.S. Power | **(18)** | 16 | **(17)** | (16) |
| Natural Gas Storage | **4** | (17) | **1** | (11) |
| Foreign exchange | **(9)** | (14) | **(15)** | (8) |
| Income taxes attributable to risk management activities | **10** | 1 | **12** | 12 |
| **Total losses from risk management activities** | **(17)** | (13) | **(25)** | (24) |

## EBITDA and EBIT by business segment

| **three months ended June 30, 2013** (unaudited - millions of $) | Natural Gas Pipelines | Oil Pipelines | Energy | Corporate | Total |
|---|---|---|---|---|---|
| **Comparable EBITDA** | **644** | **186** | **330** | **(17)** | **1,143** |
| Comparable depreciation and amortization | **(245)** | **(37)** | **(69)** | **(5)** | **(356)** |
| **Comparable EBIT** | **399** | **149** | **261** | **(22)** | **787** |

| **three months ended June 30, 2012** (unaudited - millions of $) | Natural Gas Pipelines | Oil Pipelines | Energy | Corporate | Total |
|---|---|---|---|---|---|
| **Comparable EBITDA** | 666 | 176 | 170 | (15) | 997 |
| Comparable depreciation and amortization | (234) | (36) | (72) | (4) | (346) |
| **Comparable EBIT** | 432 | 140 | 98 | (19) | 651 |

| **six months ended June 30, 2013** (unaudited - millions of $) | Natural Gas Pipelines | Oil Pipelines | Energy | Corporate | Total |
|---|---|---|---|---|---|
| **Comparable EBITDA** | **1,390** | **365** | **607** | **(51)** | **2,311** |
| Comparable depreciation and amortization | **(485)** | **(74)** | **(143)** | **(8)** | **(710)** |
| **Comparable EBIT** | **905** | **291** | **464** | **(59)** | **1,601** |

| **six months ended June 30, 2012** (unaudited - millions of $) | Natural Gas Pipelines | Oil Pipelines | Energy | Corporate | Total |
|---|---|---|---|---|---|
| **Comparable EBITDA** | 1,391 | 349 | 414 | (44) | 2,110 |
| Comparable depreciation and amortization | (466) | (72) | (145) | (7) | (690) |
| **Comparable EBIT** | 925 | 277 | 269 | (51) | 1,420 |

# Results - second quarter 2013

Net income attributable to common shares was $365 million this quarter compared to $272 million in second quarter 2012. Second quarter 2013 results included a $25 million favourable income tax adjustment due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax, in June 2013 and was excluded from comparable earnings. Second quarter 2012 included an after-tax charge of $37 million ($50 million pre-tax) related to the impact of the Sundance A PPA arbitration decision. Of this amount, $15 million ($20 million pre-tax) is excluded from 2012 comparable earnings as it related to 2011.

Net income attributable to common shares was $811 million for the six months ended June 30, 2013 compared to $624 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 was the $25 million of net income resulting from the favourable income tax adjustment noted above. These amounts were excluded from comparable earnings. The 2012 results included an after-tax charge of $15 million ($20 million pre-tax) that was excluded from 2012 comparable earnings as it related to 2011.

Comparable earnings this quarter were $357 million and $0.51 per share, $57 million and $0.08 per share higher than second quarter 2012.

This was the result of:
- higher earnings from Western Power because of higher realized power prices, higher purchased PPA volumes as well as the Sundance A PPA charge recorded in second quarter 2012
- higher equity income from Bruce Power because of incremental earnings from Units 1 and 2, which were returned to service in October 2012, and the completion of the Unit 3 West Shift Plus planned outage in June 2012, partially offset by higher planned outage days in second quarter 2013
- higher realized power prices from U.S. Power
- higher earnings from the Canadian Mainline because of 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 interest expense reflecting lower capitalized interest primarily as a result of the return to service of Bruce Power Units 1 and 2
- lower comparable interest income and other because we had 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 for the six months ended June 30, 2013 were $727 million and $1.03 per share, $64 million and $0.09 per share higher than the same period in 2012.

This was the result of:
- higher equity income from Bruce Power because of incremental earnings from Units 1, 2 and 3 and the recognition of an insurance recovery in first quarter 2013 partly offset by an increase in planned outage days
- higher realized power prices in Western Power and U.S. Power
- higher earnings from the Canadian Mainline because of 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
- lower comparable interest income and other because we had 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 losses resulting from changes in the fair value of certain risk management activities:

- $17 million ($27 million before tax) for the three months ended June 30, 2013 compared to $13 million ($14 million before tax) for the same period in 2012
- $25 million ($37 million before tax) for the six months ended June 30, 2013 compared to $24 million ($36 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 ratio, multi-year tolls through 2017 and a new incentive mechanism. In addition, we expect the recent 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 June 30 | | six months ended June 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2013** | **2012** | **2013** | **2012** |
| **Canadian Pipelines** | | | | |
| Canadian Mainline | **263** | 247 | **543** | 497 |
| NGTL System | **193** | 183 | **375** | 360 |
| Foothills | **28** | 30 | **57** | 61 |
| Other Canadian (TQM[1], Ventures LP) | **7** | 7 | **13** | 15 |
| **Canadian Pipelines - comparable EBITDA** | **491** | 467 | **988** | 933 |
| Comparable depreciation and amortization[2] | **(190)** | (177) | **(374)** | (354) |
| **Canadian Pipelines - comparable EBIT** | **301** | 290 | **614** | 579 |
| **U.S. and International** (US$) | | | | |
| ANR | **32** | 53 | **122** | 150 |
| GTN[3] | **26** | 26 | **54** | 56 |
| Great Lakes[4] | **8** | 17 | **18** | 35 |
| TC PipeLines, LP[1,5] | **13** | 18 | **30** | 38 |
| Other U.S. pipelines (Iroquois[1], Bison[3], Portland[6]) | **23** | 23 | **66** | 57 |
| International (Gas Pacifico/INNERGY[1], Guadalajara, Tamazunchale, TransGas[1]) | **25** | 30 | **51** | 58 |
| General, administrative and support costs | **(3)** | (2) | **(5)** | (4) |
| Non-controlling interests[7] | **31** | 38 | **74** | 83 |
| **U.S. Pipelines and International - comparable EBITDA** | **155** | 203 | **410** | 473 |
| Comparable depreciation and amortization[2] | **(54)** | (56) | **(109)** | (111) |
| **U.S. Pipelines and International - comparable EBIT** | **101** | 147 | **301** | 362 |
| Foreign exchange | **2** | 2 | **4** | 2 |
| **U.S. Pipelines and International - comparable EBIT** (Cdn$) | **103** | 149 | **305** | 364 |
| **Business Development comparable EBITDA and EBIT** | **(5)** | (7) | **(14)** | (18) |
| **Natural Gas Pipelines - comparable EBIT** | **399** | 432 | **905** | 925 |
| **Summary** | | | | |
| **Natural Gas Pipelines - comparable EBITDA** | **644** | 666 | **1,390** | 1,391 |
| Comparable depreciation and amortization[2] | **(245)** | (234) | **(485)** | (466) |
| **Natural Gas Pipelines - comparable EBIT** | **399** | 432 | **905** | 925 |

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 Represents our 75 per cent direct ownership interest.
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. Results reflect our 28.9 per cent ownership interest effective May 22, 2013 and 33.3 per cent from January 1 to May 22, 2013. Our effective ownership through TC PipeLines, LP prior to May 22, 2013 was 8.3 per cent of each of GTN and Bison, 16.7 per cent of Northern Border and an additional effective ownership of 15.4 per cent of Great Lakes. Our effective ownership through TC PipeLines, LP effective May 22, 2013 was 7.2 per cent of each of GTN and Bison, 14.4 per cent of Northern Border and an additional effective ownership of 13.4 per cent of Great Lakes.
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

| | three months ended June 30 | | six months ended June 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2013** | **2012** | **2013** | **2012** |
| Canadian Mainline - net income | **67** | 46 | **218** | 93 |
| Canadian Mainline - comparable earnings | **67** | 46 | **134** | 93 |
| NGTL System | **58** | 52 | **114** | 100 |
| Foothills | **5** | 4 | **9** | 9 |

## OPERATING STATISTICS - WHOLLY OWNED PIPELINES

| **six months ended June 30** | Canadian Mainline[1] | | NGTL System[2] | | ANR[3] | |
|---|---|---|---|---|---|---|
| (unaudited) | **2013** | **2012** | **2013** | **2012** | **2013** | **2012** |
| Average investment base (millions of $) | **5,871** | 5,775 | **5,882** | 5,359 | **n/a** | n/a |
| Delivery volumes (Bcf) | | | | | | |
| Total | **704** | 804 | **1,832** | 1,844 | **823** | 844 |
| Average per day | **3.9** | 4.4 | **10.1** | 10.1 | **4.6** | 4.6 |

1 Canadian Mainline's throughput volumes represent physical deliveries to domestic and export markets. Physical receipts originating at the Alberta border and in Saskatchewan for the six months ended June 30, 2013 were 397 Bcf (2012 – 455 Bcf). Average per day was 2.2 Bcf (2012 – 2.5 Bcf).

2 Field receipt volumes for the NGTL System for the six months ended June 30, 2013 were 1,840 Bcf (2012 – 1,856 Bcf). Average per day was 10.2 Bcf (2012 – 10.2 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 $21 million for the three months ended June 30, 2013 and $41 million for the six months ended June 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 $218 million for the six months ended June 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 $6 million for the three months ended June 30, 2013 and $14 million for the six months ended June 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$155 million for the three months ended June 30, 2013 and US$410 million for the six months ended June 30, 2013 compared to US$203 million and US$473 million for the same periods in 2012. This was the net effect of:

- higher costs at ANR relating to services provided by other pipelines as well as lower second quarter revenues
- lower revenues at Great Lakes because of lower rates and uncontracted capacity

- lower contributions from TransGas and Gas Pacifico/INNERGY
- higher short term and interruptible revenues at Portland.

## COMPARABLE DEPRECIATION AND AMORTIZATION

Comparable depreciation and amortization was $245 million for the three months ended June 30, 2013 and $485 million for the six months ended June 30, 2013 compared to $234 million and $466 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 June 30 | | six months ended June 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2013** | **2012** | **2013** | **2012** |
| Keystone Pipeline System | **187** | 178 | **373** | 352 |
| Oil Pipelines Business Development | **(1)** | (2) | **(8)** | (3) |
| **Oil Pipelines - comparable EBITDA** | **186** | 176 | **365** | 349 |
| Comparable depreciation and amortization | **(37)** | (36) | **(74)** | (72) |
| **Oil Pipelines - comparable EBIT** | **149** | 140 | **291** | 277 |
| **Comparable EBIT denominated as follows:** | | | | |
| Canadian dollars | **52** | 51 | **99** | 99 |
| U.S. dollars | **95** | 88 | **189** | 177 |
| Foreign exchange | **2** | 1 | **3** | 1 |
| | **149** | 140 | **291** | 277 |

Comparable EBITDA for the Keystone Pipeline System increased by $9 million for the three months ended June 30, 2013 and $21 million for the six months ended June 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 six months of 2013 were $5 million higher than the same period in 2012 because of increased activity on various development projects.

# Energy

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

| | three months ended June 30 | | six months ended June 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | 2013 | 2012 | 2013 | 2012 |
| **Canadian Power** | | | | |
| Western Power[1] | **123** | 27 | **202** | 158 |
| Eastern Power[1,2] | **75** | 73 | **170** | 166 |
| Bruce Power[1] | **59** | 31 | **90** | 18 |
| General, administrative and support costs | **(12)** | (11) | **(22)** | (22) |
| **Canadian Power - comparable EBITDA**[1] | **245** | 120 | **440** | 320 |
| Comparable depreciation and amortization[3] | **(43)** | (39) | **(86)** | (79) |
| **Canadian Power - comparable EBIT**[1] | **202** | 81 | **354** | 241 |
| **U.S. Power** (US$) | | | | |
| Northeast Power | **92** | 49 | **169** | 95 |
| General, administrative and support costs | **(12)** | (11) | **(22)** | (21) |
| **U.S. Power - comparable EBITDA** | **80** | 38 | **147** | 74 |
| Comparable depreciation and amortization | **(23)** | (30) | **(51)** | (60) |
| **U.S. Power - comparable EBIT** | **57** | 8 | **96** | 14 |
| Foreign exchange | **1** | 1 | **2** | 1 |
| **U.S. Power - comparable EBIT** (Cdn$) | **58** | 9 | **98** | 15 |
| **Natural Gas Storage** | | | | |
| Alberta Storage | **11** | 19 | **31** | 34 |
| General, administrative and support costs | **(2)** | (2) | **(4)** | (4) |
| **Natural Gas Storage - comparable EBITDA**[1] | **9** | 17 | **27** | 30 |
| Comparable depreciation and amortization[3] | **(2)** | (3) | **(5)** | (6) |
| **Natural Gas Storage - comparable EBIT**[1] | **7** | 14 | **22** | 24 |
| **Business Development comparable EBITDA and EBIT** | **(6)** | (6) | **(10)** | (11) |
| **Energy - comparable EBIT**[1] | **261** | 98 | **464** | 269 |
| | | | | |
| **Summary** | | | | |
| **Energy - comparable EBITDA**[1] | **330** | 170 | **607** | 414 |
| Comparable depreciation and amortization[3] | **(69)** | (72) | **(143)** | (145) |
| **Energy - comparable EBIT**[1] | **261** | 98 | **464** | 269 |

1 Includes our share of equity income from our investments in ASTC Power Partnership, which holds the Sundance B PPA, 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 the first Ontario Solar project in June 2013.

3 Does not include depreciation and amortization of equity investments.

Comparable EBITDA for Energy increased by $160 million for the three months ended June 30, 2013 compared to the same period in 2012. The increase was the effect of:

- higher earnings from Western Power primarily due to higher realized power prices, the Sundance A PPA charge recorded in second quarter 2012 earnings and higher purchased PPA volumes
- higher earnings from U.S. Power mainly because of higher realized power and capacity prices in New York
- 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 earnings from Unit 3, due to an outage during first and second quarter 2012, partially offset by lower Bruce B volumes due to higher planned outage days.

Comparable EBITDA for Energy increased by $193 million for the six months ended June 30, 2013 compared to the same period in 2012. The increase was the effect of:

- higher earnings from U.S. Power mainly because of higher realized power prices and higher capacity prices in New York
- higher equity income from Bruce Power because of incremental earnings from Units 1 and 2, which were returned to service in October 2012, the recognition of a business interruption insurance recovery in first quarter 2013, and higher earnings from Unit 3 due to the first and second quarter 2012 outage partially offset by the extended outage of Unit 4 in first quarter 2013 and lower Bruce B volumes due to higher planned outage days
- higher earnings from Western Power primarily due to higher realized power prices and higher purchased PPA volumes.

## 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 June 30 | | six months ended June 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2013** | 2012 | **2013** | 2012 |
| **Revenue** | | | | |
| Western Power | **161** | 106 | **303** | 330 |
| Eastern Power[1] | **91** | 98 | **200** | 201 |
| Other[2] | **22** | 22 | **53** | 47 |
| | **274** | 226 | **556** | 578 |
| **Income from equity investments[3]** | **66** | (6) | **88** | 17 |
| **Commodity purchases resold** | | | | |
| Western power | **(82)** | (43) | **(147)** | (137) |
| Other[4] | **(1)** | - | **(3)** | (2) |
| | **(83)** | (43) | **(150)** | (139) |
| Plant operating costs and other | **(59)** | (47) | **(122)** | (102) |
| Sundance A PPA arbitration decision - 2012 | **-** | (30) | **-** | (30) |
| General, administrative and support costs | **(12)** | (11) | **(22)** | (22) |
| **Comparable EBITDA** | **186** | 89 | **350** | 302 |
| Comparable depreciation and amortization[5] | **(43)** | (39) | **(86)** | (79) |
| **Comparable EBIT** | **143** | 50 | **264** | 223 |

1 Includes phase two of Cartier Wind Gros-Morne starting in November 2012 and the acquisition of the first 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 June 30 2013 | 2012 | six months ended June 30 2013 | 2012 |
|---|---|---|---|---|
| **Sales volumes (GWh)** | | | | |
| Supply | | | | |
| Generation | | | | |
| Western Power | **687** | 654 | **1,357** | 1,325 |
| Eastern Power[1] | **750** | 907 | **2,096** | 2,050 |
| Purchased | | | | |
| Sundance A & B and Sheerness PPAs[2] | **1,788** | 1,295 | **3,495** | 3,334 |
| Other purchases | **-** | 1 | **-** | 46 |
| | **3,225** | 2,857 | **6,948** | 6,755 |
| Sales | | | | |
| Contracted | | | | |
| Western Power | **1,939** | 1,741 | **3,646** | 4,036 |
| Eastern Power[1] | **750** | 907 | **2,096** | 2,050 |
| Spot | | | | |
| Western Power | **536** | 209 | **1,206** | 669 |
| | **3,225** | 2,857 | **6,948** | 6,755 |
| **Plant availability[3]** | | | | |
| Western Power[4] | **92%** | 97% | **94%** | 98% |
| Eastern Power[1,5] | **80%** | 76% | **88%** | 84% |

1 Includes phase two of Cartier Wind Gros-Morne starting in November 2012 and the acquisition of the first Ontario Solar project in June 2013.
2 Includes our 50 per cent ownership interest of Sundance B volumes through the ASTC Power Partnership. 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 $96 million for the three months ended June 30, 2013 compared to the same period in 2012. The increase was mainly due to:

- increased equity income from the ASTC Power Partnership mainly due to higher power prices
- the Sundance A PPA force majeure arbitration charge recorded in second quarter 2012
- higher purchased PPA volumes due to fewer outage days
- higher realized power prices.

Western Power's comparable EBITDA increased by $44 million for the six months ended June 30, 2013 compared to the same period 2012. The increase was mainly due to:

- increased equity income from the ASTC Power Partnership mainly due to higher power prices
- higher purchased PPA volumes due to fewer outage days
- higher realized power prices.

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. Because the plant continues to be in force majeure, we will not record further revenues and costs until the units are returned to service. See Recent Developments - Energy in this MD&A for more information about the expected return to service of Units 1 and 2.

Average spot market power prices in Alberta increased by 207 per cent to $123 per MWh for the three months ended June 30, 2013 and 88 per cent to $94 per MWh for the six months ended June 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 increased by $55 million for the three months ended June 30, 2013 compared to the same period in 2012 because of higher purchased PPA volumes and higher realized power prices.

Western Power's revenue decreased by $27 million for the six months ended June 30, 2013 compared to the same period in 2012 because of the Sundance A PPA revenue recorded in first quarter 2012 offset by higher purchased PPA volumes.

Western Power's commodity purchases resold increased by $39 million for the three months ended June 30, 2013 compared to the same period in 2012 because of higher purchased PPA volumes. Western Power's commodity purchases resold increased by $10 million for the six months ended June 30, 2013 compared to the same period in 2012 due to higher purchased PPA volumes offset by the Sundance A PPA costs recorded in first quarter 2012.

Income from Equity Investments increased by $72 million for the three months ended June 30, 2013 and $71 million for the six months ended June 30, 2013 compared to the same periods in 2012, respectively. Higher earnings from ASTC Power Partnership, which holds the Sundance B PPA, reflected higher Alberta spot power prices and higher earnings from Portlands Energy were the result of an unplanned outage in second quarter 2012.

Plant operating costs and other, which includes natural gas fuel consumed in power generation, increased by $12 million for the three months ended June 30, 2013 and $20 million for the six months ended June 30, 2013 compared to the same periods in 2012, respectively. The increases were mainly due to higher natural gas fuel prices in 2013.

Approximately 78 per cent of Western Power sales volumes were sold under contract this quarter compared to 89 per cent in second 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 June 30 2013 | 2012 | six months ended June 30 2013 | 2012 |
|---|---|---|---|---|
| **Income/(loss) from equity investments**[1] | | | | |
| Bruce A | **51** | (23) | **87** | (56) |
| Bruce B | **8** | 54 | **3** | 74 |
| | **59** | 31 | **90** | 18 |
| Comprised of: | | | | |
| Revenues | **306** | 185 | **593** | 347 |
| Operating expenses | **(172)** | (125) | **(344)** | (260) |
| Depreciation and other | **(75)** | (29) | **(159)** | (69) |
| | **59** | 31 | **90** | 18 |
| **Bruce Power - Other information** | | | | |
| Plant availability[2] | | | | |
| Bruce A[3] | **88%** | 57% | **77%** | 53% |
| Bruce B | **80%** | 95% | **79%** | 91% |
| Combined Bruce Power | **84%** | 84% | **78%** | 72% |
| Planned outage days | | | | |
| Bruce A | **33** | 62 | **123** | 153 |
| Bruce B | **70** | - | **140** | 46 |
| Unplanned outage days | | | | |
| Bruce A | **-** | - | **8** | - |
| Bruce B | **3** | 19 | **12** | 23 |
| Sales volumes (GWh)[1] | | | | |
| Bruce A[3] | **2,464** | 895 | **4,561** | 1,642 |
| Bruce B | **1,726** | 2,047 | **3,460** | 3,956 |
| | **4,190** | 2,942 | **8,021** | 5,598 |
| Realized sales price per MWh[4] | | | | |
| Bruce A | **$71** | $68 | **$70** | $67 |
| Bruce B | **$54** | $56 | **$53** | $55 |
| Combined Bruce Power | **$63** | $58 | **$61** | $58 |

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 $74 million for the three months ended June 30, 2013 and $143 million for the six months ended June 30, 2013 compared to the same periods in 2012. The increases were 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 and the impact the event had on Bruce A in 2012 and 2013.

These increases were 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 decreased by $46 million for the three months ended June 30, 2013 and $71 million for the six months ended June 30, 2013 compared to the same periods in 2012. These decreases were mainly due to lower volumes and higher operating costs resulting from higher planned outage days and higher lease expense.

Provisions in the Bruce B lease agreement with Ontario Power Generation provide for a reduction in annual lease expense if the annual average Ontario spot price for electricity is less than $30 per MWh. Lease expense recognized in the three and six months ended June 30, 2012 reflected an annual average spot price below $30 per MWh. At this time, it is uncertain if the annual average spot price will be below $30 per MWh in 2013 and therefore no reduction to 2013 rent expense was recorded in second quarter 2013.

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 | $70.96 |
| 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 June 30** | | **six months ended June 30** | |
|---|---|---|---|---|
| (unaudited - millions of US $) | **2013** | **2012** | **2013** | **2012** |
| **Revenue** | | | | |
| Power[1] | **317** | 233 | **750** | 428 |
| Capacity | **77** | 66 | **124** | 106 |
| Other[2] | **17** | 5 | **46** | 24 |
| | **411** | 304 | **920** | 558 |
| Commodity purchases resold | **(197)** | (163) | **(503)** | (280) |
| Plant operating costs and other[2] | **(122)** | (92) | **(248)** | (183) |
| General, administrative and support costs | **(12)** | (11) | **(22)** | (21) |
| **Comparable EBITDA** | **80** | 38 | **147** | 74 |
| Comparable depreciation and amortization | **(23)** | (30) | **(51)** | (60) |
| **Comparable EBIT** | **57** | 8 | **96** | 14 |

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

| | three months ended June 30 | | six months ended June 30 | |
|---|---|---|---|---|
| (unaudited) | **2013** | **2012** | **2013** | **2012** |
| **Physical sales volumes (GWh)** | | | | |
| Supply | | | | |
| Generation | **1,761** | 1,787 | **2,812** | 2,941 |
| Purchased | **1,878** | 1,687 | **4,357** | 3,257 |
| | **3,639** | 3,474 | **7,169** | 6,198 |
| **Plant availability**[1] | **91%** | 82% | **85%** | 81% |

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$80 million for the three months ended June 30, 2013 and US$147 million for the six months ended June 30, 2013 compared to US$38 million and US$74 million for the same periods in 2012. These increases included the net effect of:

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

Commodity prices were higher for the three and six months ended June 30, 2013 compared to the same periods in 2012. In 2012, oversupply conditions in the North American natural gas market reduced these prices. In 2013, natural gas prices recovered and storage levels fell primarily due to colder first quarter weather. The increase in gas prices has translated into higher spot power prices in the predominantly gas-fired New England and New York power markets in the first half of 2013.

Physical sales volumes for the three and six months ended June 30, 2013 were higher than the same periods in 2012 due to higher purchased volumes to serve increased sales to wholesale, commercial and industrial customers in the New England and PJM markets. Generation volumes were slightly lower, mainly due to lower generation in our natural gas fueled facilities in both New York and New England partly offset by a higher generation at our hydro facilities.

Power revenue was US$317 million for the three months ended June 30, 2013 and US$750 million for the six months ended June 30, 2013 compared to US$233 million and US$428 million for the same periods in 2012. This was mainly due to the combination of higher realized power prices and higher sales volumes to wholesale, commercial and industrial customers.

Capacity revenue was US$77 million for the three months ended June 30, 2013 and US$124 million for the six months ended June 30, 2013 compared to US$66 million and US$106 million for the same periods in 2012. New York Zone J spot capacity prices are approximately 10 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$197 million for the three months ended June 30, 2013 and US$503 million for the six months ended June 30, 2013 compared to US$163 million and US$280 million for the same periods in 2012 because we purchased higher volumes of power at higher prices to fulfill increased power sales commitments to wholesale, commercial and industrial customers at higher realized power prices.

Plant operating costs and other, which includes fuel gas consumed in generation, increased by US$30 million for the three months ended June 30, 2013 and US$65 million for the six months ended June 30, 2013 compared to the same periods in 2012 because of higher natural gas fuel prices.

As at June 30, 2013, approximately 2,200 GWh or 44 per cent of U.S. Power's planned generation is contracted for the remainder of 2013, and 2,500 GWh or 28 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 June 30 | | six months ended June 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2013** | **2012** | **2013** | **2012** |
| Alberta Storage[1] | **11** | 19 | **31** | 34 |
| General, administrative and support costs | **(2)** | (2) | **(4)** | (4) |
| **Comparable EBITDA** | **9** | 17 | **27** | 30 |
| Comparable depreciation and amortization | **(2)** | (3) | **(5)** | (6) |
| **Comparable EBIT** | **7** | 14 | **22** | 24 |

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 June 30, 2013 and $3 million for the six months ended June 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

### NEB decision on the Canadian Restructuring Proposal

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, including tolls for 2012 and 2013. The decision significantly alters the regulatory framework that has formed the basis for more than $10 billion of regulated pipeline investment over the last sixty years.

On May 1, 2013, we filed an application for a review and variance of the decision and order. The NEB dismissed the review and variance application on June 11, 2013, and released its reasons for the dismissal on July 22, 2013. The NEB did however recognize that changes proposed by us to the Canadian Mainline's Tariff would be considered as a separate application through an oral hearing process to be heard in September.

We are effectively operating under the new decision environment as of July 1. We have submitted the tariff change application and will manage that process through the oral hearing and await a decision on those changes.

### NGTL System expansion projects

We continued to expand the NGTL System (formerly known as the Alberta System) and have placed $700 million of new facilities in service in 2013. We have applied and received approval from the NEB for an additional $130 million of new facilities. To date in 2013, we have applied for an additional $145 million of facilities that remain subject to NEB approval. We are planning regulatory applications for further expansion into B.C. and estimate the cost of the facilities to be between $1.0 billion and $1.5 billion to connect and transport new gas supply that will be delivered to the Prince Rupert Gas Transmission Project (PRGT) as well as other markets served by the NGTL System. In third quarter 2013, we expect to begin an open season to provide delivery service through a transportation by others arrangement on Coastal GasLink to Vanderhoof, B.C.

### Prince Rupert Gas Transmission Project

The British Columbia Environmental Assessment Office issued its Section 10 Order in June 2013 indicating that the project is reviewable and requires an environmental assessment certificate. The Canadian Environmental Assessment Agency (CEAA) initiated the public comment period with respect to the project in June 2013.

### 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 CEAA.

### Portland Natural Gas Transmission System

We concluded an open season in June 2013 with certain markets throughout the Northeast U.S. and Atlantic Canada expressing interest and others indicating an interest in turning back portions of our capacity. The interest generated for incremental capacity did not meet the threshold level required to go forward with an increase in capacity at this time. PNGTS continues to look for market opportunities to further develop growth of the system.

### 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 closing adjustments for working capital of $17 million.

Through our subsidiaries, we continue to hold a 30 per cent direct ownership interest in both pipelines. We also hold 28.9 per cent interest in TC PipeLines, LP and are the General Partner.

### Mexican Pipelines
The construction of the Tamazunchale Pipeline Extension project and related compression facilities is proceeding. 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 36-inch pipeline from Cushing, Oklahoma to the U.S. Gulf Coast and expect to begin delivering crude oil to Port Arthur, Texas at the end of 2013. Construction is approximately 85 per cent complete and we estimate the cost of the Cushing to Port Arthur facilities to be US$2.3 billion.

Construction of the 76 km (47 mile) Houston Lateral pipeline to transport crude oil to Houston refineries is expected to be complete in 2014 at a cost of US$300 million.

The Gulf Coast Project will have a capacity of up to 700,000 barrels per day.

### Keystone XL Pipeline
In January 2013, the Governor of Nebraska approved our proposed re-route after the Nebraska Department of Environmental Quality issued its final evaluation report noting that construction and operation of Keystone XL is expected to have minimal environmental impacts in Nebraska.

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 the public comment during a National Interest Determination period of up to 90 days, before making a decision on our Presidential Permit application.

We now 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 June 30, 2013, we had invested US$1.9 billion in the project.

### Energy East Pipeline
On June 17, 2013, we concluded an open season to obtain firm commitments for a pipeline to transport up to 850,000 Bbl/d of crude oil from western receipt points to eastern Canadian markets and are currently reviewing the results.

The Energy East Pipeline project involves converting natural gas pipeline capacity in approximately 3,000 km (1,870 miles) of our existing Canadian Mainline to crude oil service and constructing up to approximately 1,400 km (870 miles) of new pipeline.

We have begun Aboriginal and stakeholder engagement and associated field work as part of our initial design and planning. If we determine that there is sufficient commercial support for the project, we will apply for regulatory approval to build and operate the facilities, with a potential in-service date of late 2017.

### Northern Courier Pipeline
On April 25, 2013, we filed a permit application with the Alberta Energy Regulator after completing the required Aboriginal and stakeholder engagement and associated field work. We continue to work with the Fort Hills Energy Limited Partnership on the development of this project.

### Heartland Pipeline and TC Terminals
On May 2, 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.

On May 30, 2013, we filed a permit application for the terminal facility with the Alberta Energy Regulator and expect to file an application for the pipeline later in 2013.

### Grand Rapids Pipeline

On May 23, 2013, we filed a permit application with the Alberta Energy 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. We expect to close the acquisition of the remaining projects in 2013 and 2014, 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

TransAlta previously announced that it expected Sundance A Units 1 and 2 to be returned to service in the fall of 2013. They subsequently reported an earlier return to service date for Unit 1 of July 31, 2013. TransAlta has not announced any change in the return to service date for Unit 2.

### Bruce Power

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.

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.

### 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. 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 June 30 2013 | 2012 | six months ended June 30 2013 | 2012 |
|---|---|---|---|---|
| Comparable interest expense | **(252)** | (239) | **(509)** | (481) |
| Comparable interest income and other | **(2)** | 19 | **16** | 44 |
| Comparable income taxes | **(133)** | (91) | **(292)** | (231) |
| Net income attributable to non-controlling interests | **(23)** | (26) | **(54)** | (61) |

| (unaudited - millions of $) | three months ended June 30 2013 | 2012 | six months ended June 30 2013 | 2012 |
|---|---|---|---|---|
| **Comparable interest on long-term debt** | | | | |
| (including interest on junior subordinated notes) | | | | |
| Canadian dollar-denominated | **123** | 127 | **245** | 255 |
| U.S. dollar-denominated (US$) | **185** | 183 | **373** | 369 |
| Foreign exchange | **5** | - | **6** | - |
| | **313** | 310 | **624** | 624 |
| Other interest and amortization expense | **(1)** | 5 | **-** | 7 |
| Capitalized interest | **(60)** | (76) | **(115)** | (150) |
| **Comparable interest expense** | **252** | 239 | **509** | 481 |

Comparable interest expense was $252 million for the three months ended June 30, 2013 and $509 million for the six months ended June 30, 2013 compared to $239 million and $481 million for the same periods 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 increased capitalized interest for the Gulf Coast Project
- lower interest expense due to Canadian and U.S. dollar-denominated debt maturities, partially offset by debt issues of US$750 million in January 2013, US$1 billion in August 2012 and US$500 million in March 2012.

Comparable interest income and other was a loss of $2 million for the three months ended June 30, 2013 and a gain of $16 million for the six months ended June 30, 2013 compared to gains of $19 million and $44 million for the same periods 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 were $133 million for the three months ended June 30, 2013 and $292 million for the six months ended June 30, 2013 compared to $91 million and $231 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 June 30 | | six months ended June 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2013** | **2012** | **2013** | **2012** |
| Funds generated from operations[1] | **955** | 729 | **1,871** | 1,600 |
| (Increase)/decrease in operating working capital | **(114)** | 14 | **(324)** | (155) |
| Net cash provided by operations | **841** | 743 | **1,547** | 1,445 |

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 $841 million for the three months ended June 30, 2013 and $1,547 million for the six months ended June 30, 2013 compared to $743 million and $1,445 million for the same periods in 2012, respectively, as a result of our increase in earnings, partly offset by increases in operating working capital.

At June 30, 2013, our current assets were $2.8 billion and current liabilities were $6.7 billion, leaving us with a working capital deficit of $3.9 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 June 30 | | six months ended June 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2013** | **2012** | **2013** | **2012** |
| Capital expenditures | **1,109** | 397 | **2,038** | 861 |
| Equity investments | **39** | 197 | **71** | 413 |
| Acquisition | **55** | - | **55** | - |

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

On June 28, 2013, we completed the acquisition of the first Ontario Solar project for $55 million.

## CASH PROVIDED BY/(USED IN) FINANCING ACTIVITIES

| | three months ended June 30 | | six months ended June 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2013** | **2012** | **2013** | **2012** |
| Long-term debt issued, net of issue costs | **10** | 1 | **744** | 493 |
| Long-term debt repaid | **(695)** | (222) | **(709)** | (770) |
| Notes payable issued, net | **1,388** | 635 | **559** | 589 |
| Dividends and distributions paid | **(386)** | (359) | **(736)** | (702) |
| Equity financing activities | **406** | 4 | **1,024** | 18 |

In January 2013, we issued US$750 million of senior notes, maturing on January 15, 2016 and bearing interest at 0.75 per cent. These notes were issued under the US$4.0 billion debt shelf prospectus filed in November 2011.

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 $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 rates of 3.69 and 4.55 per cent per annum, respectively.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.

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 July 25, 2013 we declared quarterly dividends as follows:

| Quarterly dividend on our common shares |
|---|
| $0.46 per share (for the quarter ending September 30, 2013) |
| Payable on October 31, 2013 to shareholders of record at the close of business on September 30, 2013 |

| Quarterly dividends on our preferred shares |
|---|
| **Series 1** $0.2875 (for the quarter ending September 30, 2013) |
| **Series 3** $0.25 (for the quarter ending September 30, 2013) |
| Payable on September 30, 2013 to shareholders of record at the close of business on September 3, 2013 |
| **Series 5** $0.275 (for the three month period ending October 30, 2013) |
| **Series 7** $0.25 (for the three month period ending October 30, 2013) |
| Payable on October 30, 2013 to shareholders of record at the close of business on September 30, 2013 |

## SHARE INFORMATION

| at July 22, 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 June 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. | October 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 | $330 million | TCPL, TCPL USA | Demand lines for issuing letters of credit and as a source of additional liquidity. At June 30, 2013, we had outstanding $670 million in letters of credit under these lines | Demand |

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

## CONTRACTUAL OBLIGATIONS

Our capital commitments have decreased by $600 million primarily due to the completion or advancement of capital projects. Our other purchase commitments decreased by $180 million. There were no other material changes to our contractual obligations in second 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 12 month period and making sure we have adequate cash balances, cash flow from operations, committed and demand credit facilities and access to capital markets to meet our operating, financing and capital expenditure obligations under both normal and stressed economic conditions.

### COUNTERPARTY CREDIT RISK

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

- accounts receivable
- portfolio investments
- the fair value of derivative assets
- notes, loans and advances receivable.

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At June 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 $263 million with one counterparty at June 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 transactions, including foreign exchange exposures 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 or pay them to shippers according to the terms of the shipping agreements.

### AVERAGE EXCHANGE RATE - U.S. TO CANADIAN DOLLARS

| | |
|---|---|
| Second quarter 2013 | 1.03 |
| Second quarter 2012 | 1.01 |

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

| (unaudited - millions of US$) | three months ended June 30 2013 | 2012 | six months ended June 30 2013 | 2012 |
|---|---|---|---|---|
| U.S. and International Natural Gas Pipelines comparable EBIT | **101** | 147 | **301** | 362 |
| U.S. Oil Pipelines comparable EBIT | **95** | 88 | **189** | 177 |
| U.S. Power comparable EBIT | **57** | 8 | **96** | 14 |
| Interest expense on U.S. dollar-denominated long-term debt | **(185)** | (183) | **(373)** | (369) |
| Capitalized interest on U.S. capital expenditures | **49** | 27 | **93** | 53 |
| U.S. non-controlling interests and other | **(39)** | (45) | **(87)** | (96) |
| | **78** | 42 | **219** | 141 |

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

| **Asset/(liability)** (unaudited - millions of $) | June 30, 2013 Fair value[1] | Notional amount | December 31, 2012 Fair value[1] | Notional amount |
|---|---|---|---|---|
| U.S. dollar cross-currency swaps (maturing 2013 to 2019)[2] | **(137)** | **US 3,900** | 82 | US 3,800 |
| U.S. dollar forward foreign exchange contracts (maturing 2013 to 2014) | **(29)** | **US 1,050** | - | US 250 |
| | **(166)** | **US 4,950** | 82 | US 4,050 |

1 Fair values equal carrying values.
2 Net Income in the three and six months ended June 30, 2013 included net realized gains of $7 million and $14 million, respectively, (2012 - gains of $7 million and $14 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 $) | June 30, 2013 | December 31, 2012 |
|---|---|---|
| Carrying value | **12.2 (US 11.7)** | 11.1 (US 11.2) |
| Fair value | **14.2 (US 13.5)** | 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 $) | June 30, 2013 | December 31, 2012 |
|---|---|---|
| Other current assets | **30** | 71 |
| Intangible and other assets | **2** | 47 |
| Accounts payable and other | **52** | 6 |
| Other long-term liabilities | **146** | 30 |

## NON-DERIVATIVE FINANCIAL INSTRUMENTS SUMMARY

| | June 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 | **674** | **674** | 551 | 551 |
| Accounts receivable and other[3] | **1,301** | **1,350** | 1,288 | 1,337 |
| Available for sale assets | **47** | **47** | 44 | 44 |
| | **2,022** | **2,071** | 1,883 | 1,932 |
| **Financial liabilities**[4] | | | | |
| Notes payable | **2,900** | **2,900** | 2,275 | 2,275 |
| Accounts payable and other long-term liabilities[5] | **1,114** | **1,114** | 1,535 | 1,535 |
| Accrued interest | **380** | **380** | 368 | 368 |
| Long-term debt | **19,699** | **23,474** | 18,913 | 24,573 |
| Junior subordinated notes | **1,050** | **1,105** | 994 | 1,054 |
| | **25,143** | **28,973** | 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 June 30, 2013, financial assets of $1.1 billion (December 31, 2012 - $1.1 billion) are included in accounts receivable, $72 million (December 31, 2012 - $40 million) in other current assets and $225 million (December 31, 2012 - $240 million) in intangible and other assets.

4 Condensed consolidated statement of income in the three and six months ended June 30, 2013 included gains of $3 million and losses of $7 million, respectively, (2012 - gains of $3 million and losses of $12 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 June 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 June 30, 2013, financial liabilities of $1.1 billion (December 31, 2012 - $1.5 billion) are included in accounts payable and $36 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<br>(unaudited - millions of $ unless noted otherwise) | Power | Natural gas | Foreign exchange | Interest |
|---|---|---|---|---|
| **Derivative instruments held for trading**[1] | | | | |
| Fair values[2] | | | | |
| Assets | **$141** | **$70** | **$-** | **$11** |
| Liabilities | **$(183)** | **$(99)** | **$(17)** | **$(11)** |
| Notional values | | | | |
| Volumes[3] | | | | |
| Sales | **35,445** | **64** | **-** | **-** |
| Purchases | **34,750** | **102** | **-** | **-** |
| Canadian dollars | **-** | **-** | **-** | **620** |
| U.S. dollars | **-** | **-** | **US 1,274** | **US 200** |
| Net unrealized gains/(losses) in the period[4] | | | | |
| three months ended June 30, 2013 | **$5** | **$(21)** | **$(10)** | **$-** |
| six months ended June 30, 2013 | **$(3)** | **$(12)** | **$(16)** | **$-** |
| Net realized losses in the period[4] | | | | |
| three months ended June 30, 2013 | **$(29)** | **$(5)** | **$(6)** | **$-** |
| six months ended June 30, 2013 | **$(36)** | **$(7)** | **$(7)** | **$-** |
| Maturity dates | **2013-2017** | **2013-2016** | **2013-2014** | **2013-2016** |
| **Derivative instruments in hedging relationships**[5,6] | | | | |
| Fair values[2] | | | | |
| Assets | **$37** | **$-** | **$-** | **$7** |
| Liabilities | **$(103)** | **$(1)** | **$(1)** | **$-** |
| Notional values | | | | |
| Volumes[3] | | | | |
| Sales | **6,283** | **-** | **-** | **-** |
| Purchases | **13,206** | **-** | **-** | **-** |
| U.S. dollars | **-** | **-** | **US 15** | **US 200** |
| Cross-currency | **-** | **-** | **-** | **-** |
| Net realized (losses)/gains in the period[4] | | | | |
| three months ended June 30, 2013 | **$(84)** | **$(1)** | **$-** | **$2** |
| six months ended June 30, 2013 | **$(11)** | **$(1)** | **$-** | **$4** |
| Maturity dates | **2013-2018** | **2013** | **2014** | **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. 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 six months ended June 30, 2013, net realized gains on fair value hedges were $2 million and $4 million, respectively, and were included in interest expense. For the three and six months ended June 30, 2013, we did not record any amounts in net income related to ineffectiveness for fair value hedges.

6 For the three and six months ended June 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**<br>(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 (losses)/gains in the period[5] | | | | |
| three months ended June 30, 2012 | $(12) | $4 | $(14) | $- |
| six months ended June 30, 2012 | $(19) | $(10) | $(8) | $- |
| Net realized (losses)/gains in the period[5] | | | | |
| three months ended June 30, 2012 | $(6) | $(5) | $6 | $- |
| six months ended June 30, 2012 | $9 | $(15) | $15 | $- |
| 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 | - | - | - |
| Purchases | 15,184 | 1 | - | - |
| U.S. dollars | - | - | US 12 | US 350 |
| Cross-currency | - | - | 136/US 100 | - |
| Net realized (losses)/gains in the period[5] | | | | |
| three months ended June 30, 2012 | $(26) | $(8) | $- | $2 |
| six months ended June 30, 2012 | $(58) | $(14) | $- | $3 |
| 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 six months ended June 30, 2012 were $2 million and $4 million, respectively, and were included in Interest expense. In the three and six months ended June 30, 2012, we did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

7 For the three and six months ended June 30, 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 $) | June 30, 2013 | December 31, 2012 |
|---|---|---|
| **Current** | | |
| Other current assets | **187** | 259 |
| Accounts payable and other | **(341)** | (283) |
| **Long term** | | |
| Intangible and other assets | **111** | 187 |
| Other long-term liabilities | **(272)** | (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]** **three months ended June 30** (unaudited – millions of $, pre-tax) | **Power** | | **Natural gas** | | **Foreign exchange** | | **Interest** | |
|---|---|---|---|---|---|---|---|---|
| | **2013** | **2012** | **2013** | **2012** | **2013** | **2012** | **2013** | **2012** |
| Change in fair value of derivative instruments recognized in OCI (effective portion) | **(70)** | 44 | **-** | (4) | **2** | 4 | **-** | - |
| Reclassification of gains and losses on derivative instruments from AOCI to net income (effective portion) | **12** | 28 | **2** | 15 | **-** | - | **4** | 4 |
| Gains and losses on derivative instruments recognized in earnings (ineffective portion) | **(2)** | 7 | **-** | 1 | **-** | - | **-** | - |

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

| **Cash flow hedges[1]** **six months ended June 30** (unaudited – millions of $, pre-tax) | **Power** | | **Natural gas** | | **Foreign exchange** | | **Interest** | |
|---|---|---|---|---|---|---|---|---|
| | **2013** | **2012** | **2013** | **2012** | **2013** | **2012** | **2013** | **2012** |
| Change in fair value of derivative instruments recognized in OCI (effective portion) | **(34)** | (22) | **-** | (14) | **4** | 1 | **-** | - |
| Reclassification of gains and losses on derivative instruments from AOCI to net income (effective portion) | **1** | 75 | **2** | 28 | **-** | - | **8** | 10 |
| Gains and losses on derivative instruments recognized in earnings (ineffective portion) | **(7)** | 1 | **-** | (1) | **-** | - | **-** | - |

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 June 30, 2013, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $36 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 June 30, 2013, we would have been required to provide collateral of $36 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.<br><br>Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers.<br><br>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.<br><br>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)[1,2] | | Significant unobservable inputs (Level III)[2] | | Total | |
|---|---|---|---|---|---|---|---|---|
| (unaudited – millions of $, pre-tax) | Jun 30, 2013 | Dec 31, 2012 | Jun 30, 2013 | Dec 31, 2012 | Jun 30, 2013 | Dec 31, 2012 | Jun 30, 2013 | Dec 31, 2012 |
| Derivative instrument assets: | | | | | | | | |
| Power commodity contracts | **-** | - | **171** | 213 | **7** | 2 | **178** | 215 |
| Natural gas commodity contracts | **65** | 75 | **5** | 13 | **-** | - | **70** | 88 |
| Foreign exchange contracts | **-** | - | **32** | 119 | **-** | - | **32** | 119 |
| Interest rate contracts | **-** | - | **18** | 24 | **-** | - | **18** | 24 |
| Derivative instrument liabilities: | | | | | | | | |
| Power commodity contracts | **-** | - | **(279)** | (269) | **(7)** | (4) | **(286)** | (273) |
| Natural gas commodity contracts | **(85)** | (95) | **(15)** | (11) | **-** | - | **(100)** | (106) |
| Foreign exchange contracts | **-** | - | **(216)** | (76) | **-** | - | **(216)** | (76) |
| Interest rate contracts | **-** | - | **(11)** | (14) | **-** | - | **(11)** | (14) |
| Non-derivative financial instruments: | | | | | | | | |
| Available for sale assets | **-** | - | **47** | 44 | **-** | - | **47** | 44 |
| | **(20)** | (20) | **(248)** | 43 | **-** | (2) | **(268)** | 21 |

1 There were no transfers between Level I and Level II for the six months ended June 30, 2013 and 2012.
2 There were no transfers between Level II and Level III for the six months ended June 30, 2013 and 2012.

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

| | Derivatives[1] | | | |
|---|---|---|---|---|
| | three months ended June 30 | | six months ended June 30 | |
| (unaudited - millions of $, pre-tax) | **2013** | 2012 | **2013** | 2012 |
| Balance at beginning of period | **1** | (11) | **(2)** | (15) |
| Settlements | **1** | (1) | **1** | (1) |
| Transfers out of Level III | **(1)** | 1 | **(1)** | 1 |
| Total (losses)/gains included in OCI | **(1)** | 18 | **2** | 22 |
| Balance at end of period | **-** | 7 | **-** | 7 |

1 For the three and six months ended June 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 $5 million decrease or increase, respectively, in the fair value of outstanding derivative instruments included in Level III at June 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 June 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 second quarter 2013 that had or are likely to have a material impact on our internal control over financial reporting.

Management is in the process of implementing an Enterprise Resource Planning (ERP) system that will likely affect some processes supporting internal control over financial reporting. The phased implementation period, originally planned to begin July 1, 2013, has been deferred to January 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 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 be material.

**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 be material.

# QUARTERLY RESULTS

## SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

| (unaudited – millions of $, except per share amounts) | 2013 | | 2012 | | | | 2011 | |
|---|---|---|---|---|---|---|---|---|
| | **Second** | **First** | **Fourth** | **Third** | **Second** | **First** | **Fourth** | **Third** |
| Revenues | **2,009** | 2,252 | 2,089 | 2,126 | 1,847 | 1,945 | 2,015 | 2,043 |
| Net income attributable to common shares | **365** | 446 | 306 | 369 | 272 | 352 | 376 | 386 |
| Share Statistics | | | | | | | | |
| Net Income per common share - basic and diluted | **$0.52** | $0.63 | $0.43 | $0.52 | $0.39 | $0.50 | $0.53 | $0.55 |
| Dividend declared per common share | **$0.46** | $0.46 | $0.44 | $0.44 | $0.44 | $0.44 | $0.42 | $0.42 |

### FACTORS AFFECTING QUARTERLY FINANCIAL INFORMATION BY BUSINESS SEGMENT

Quarter-over-quarter revenues and net incomes 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

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.

Third quarter 2011
- EBIT included net unrealized losses of $43 million pre-tax ($30 million after-tax) from certain risk management activities.

# Condensed consolidated statement of income

| (unaudited - millions of Canadian $ except per share amounts) | three months ended June 30 2013 | three months ended June 30 2012 | six months ended June 30 2013 | six months ended June 30 2012 |
|---|---|---|---|---|
| **Revenues** | | | | |
| Natural gas pipelines | **1,031** | 1,034 | **2,188** | 2,119 |
| Oil pipelines | **278** | 251 | **549** | 510 |
| Energy | **700** | 562 | **1,524** | 1,163 |
| | **2,009** | 1,847 | **4,261** | 3,792 |
| **Income from Equity Investments** | **153** | 65 | **246** | 125 |
| **Operating and Other Expenses** | | | | |
| Plant operating costs and other | **648** | 627 | **1,289** | 1,219 |
| Commodity purchases resold | **283** | 208 | **659** | 421 |
| Property taxes | **106** | 100 | **215** | 215 |
| Depreciation and amortization | **356** | 346 | **723** | 690 |
| | **1,393** | 1,281 | **2,886** | 2,545 |
| **Financial Charges/(Income)** | | | | |
| Interest expense | **252** | 239 | **510** | 481 |
| Interest income and other | **11** | (5) | **(2)** | (36) |
| | **263** | 234 | **508** | 445 |
| **Income before Income Taxes** | **506** | 397 | **1,113** | 927 |
| **Income Taxes (Recovery)/Expense** | | | | |
| Current | **(36)** | 39 | **43** | 95 |
| Deferred | **134** | 46 | **170** | 119 |
| | **98** | 85 | **213** | 214 |
| **Net Income** | **408** | 312 | **900** | 713 |
| Net income attributable to non-controlling interests | **23** | 26 | **54** | 61 |
| **Net Income Attributable to Controlling Interests** | **385** | 286 | **846** | 652 |
| Preferred share dividends | **20** | 14 | **35** | 28 |
| **Net Income Attributable to Common Shares** | **365** | 272 | **811** | 624 |
| **Net Income per Common Share** | | | | |
| Basic and diluted | **$0.52** | $0.39 | **$1.15** | $0.89 |
| **Dividends Declared per Common Share** | **$0.46** | $0.44 | **$0.92** | $0.88 |
| **Weighted Average Number of Common Shares** (millions) | | | | |
| Basic | **707** | 704 | **706** | 704 |
| Diluted | **708** | 705 | **707** | 705 |

See accompanying notes to the condensed consolidated financial statements.

# Condensed consolidated statement of comprehensive income

| (unaudited - millions of Canadian $) | three months ended June 30 2013 | three months ended June 30 2012 | six months ended June 30 2013 | six months ended June 30 2012 |
|---|---|---|---|---|
| **Net Income** | **408** | 312 | **900** | 713 |
| **Other Comprehensive Income, Net of Income Taxes** | | | | |
| Foreign currency translation gains on investments in foreign operations | **225** | 114 | **336** | 7 |
| Change in fair value of net investment hedges | **(135)** | (61) | **(184)** | (23) |
| Change in fair value of cash flow hedges | **(44)** | 28 | **(23)** | (17) |
| Reclassification to net income of gains on cash flow hedges | **11** | 27 | **7** | 72 |
| Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans | **6** | 4 | **12** | 14 |
| Other comprehensive (loss)/income on equity investments | **(2)** | (3) | **(3)** | 2 |
| Other comprehensive income (Note 7) | **61** | 109 | **145** | 55 |
| **Comprehensive Income** | **469** | 421 | **1,045** | 768 |
| Comprehensive income attributable to non-controlling interests | **60** | 46 | **111** | 64 |
| **Comprehensive Income Attributable to Controlling Interests** | **409** | 375 | **934** | 704 |
| Preferred share dividends | **20** | 14 | **35** | 28 |
| **Comprehensive Income Attributable to Common Shares** | **389** | 361 | **899** | 676 |

See accompanying notes to the condensed consolidated financial statements.

# Condensed consolidated statement of cash flows

| (unaudited - millions of Canadian $) | three months ended June 30 2013 | three months ended June 30 2012 | six months ended June 30 2013 | six months ended June 30 2012 |
|---|---|---|---|---|
| **Cash Generated from Operations** | | | | |
| Net income | **408** | 312 | **900** | 713 |
| Depreciation and amortization | **356** | 346 | **723** | 690 |
| Deferred income taxes | **134** | 46 | **170** | 119 |
| Income from equity investments | **(153)** | (65) | **(246)** | (125) |
| Distributed earnings received from equity investments | **180** | 74 | **264** | 157 |
| Employee post-retirement benefits funding lower than expense | **11** | 5 | **26** | 12 |
| Other | **19** | 11 | **34** | 34 |
| (Increase)/decrease in operating working capital | **(114)** | 14 | **(324)** | (155) |
| Net cash provided by operations | **841** | 743 | **1,547** | 1,445 |
| **Investing Activities** | | | | |
| Capital expenditures | **(1,109)** | (397) | **(2,038)** | (861) |
| Equity investments | **(39)** | (197) | **(71)** | (413) |
| Acquisition | **(55)** | - | **(55)** | - |
| Deferred amounts and other | **(144)** | 79 | **(164)** | 42 |
| Net cash used in investing activities | **(1,347)** | (515) | **(2,328)** | (1,232) |
| **Financing Activities** | | | | |
| Dividends on common and preferred shares | **(351)** | (324) | **(666)** | (634) |
| Distributions paid to non-controlling interests | **(35)** | (35) | **(70)** | (68) |
| Notes payable issued, net | **1,388** | 635 | **559** | 589 |
| Long-term debt issued, net of issue costs | **10** | 1 | **744** | 493 |
| Repayment of long-term debt | **(695)** | (222) | **(709)** | (770) |
| Common shares issued, net of issue costs | **23** | 4 | **55** | 18 |
| Partnership units of subsidiary issued, net of issue costs | **384** | - | **384** | - |
| Preferred shares issued, net of issue costs | **(1)** | - | **585** | - |
| Net cash provided by/(used in) financing activities | **723** | 59 | **882** | (372) |
| **Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents** | **14** | 7 | **22** | (5) |
| **Increase/(decrease) in Cash and Cash Equivalents** | **231** | 294 | **123** | (164) |
| **Cash and Cash Equivalents** | | | | |
| Beginning of period | **443** | 196 | **551** | 654 |
| **Cash and Cash Equivalents** | | | | |
| End of period | **674** | 490 | **674** | 490 |

See accompanying notes to the condensed consolidated financial statements.

# Condensed consolidated balance sheet

| (unaudited - millions of Canadian $) | June 30 2013 | December 31 2012 |
|---|---|---|
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | **674** | 551 |
| Accounts receivable | **1,051** | 1,052 |
| Inventories | **224** | 224 |
| Other | **816** | 997 |
| | **2,765** | 2,824 |
| **Plant, Property and Equipment,** net of accumulated depreciation of $17,327 and $16,540, respectively | **35,699** | 33,713 |
| **Equity Investments** | **5,412** | 5,366 |
| **Goodwill** | **3,653** | 3,458 |
| **Regulatory Assets** | **1,921** | 1,629 |
| **Intangible and Other Assets** | **1,433** | 1,343 |
| | **50,883** | 48,333 |
| **LIABILITIES** | | |
| **Current Liabilities** | | |
| Notes payable | **2,900** | 2,275 |
| Accounts payable and other | **1,968** | 2,344 |
| Accrued interest | **380** | 368 |
| Current portion of long-term debt | **1,477** | 894 |
| | **6,725** | 5,881 |
| **Regulatory Liabilities** | **226** | 268 |
| **Other Long-Term Liabilities** | **926** | 882 |
| **Deferred Income Tax Liabilities** | **4,088** | 3,953 |
| **Long-Term Debt** | **18,222** | 18,019 |
| **Junior Subordinated Notes** | **1,050** | 994 |
| | **31,237** | 29,997 |
| **EQUITY** | | |
| Common shares, no par value | **12,131** | 12,069 |
| Issued and outstanding: June 30, 2013 - 707 million shares | | |
| December 31, 2012 - 705 million shares | | |
| Preferred shares | **1,813** | 1,224 |
| Additional paid-in capital | **404** | 379 |
| Retained earnings | **4,846** | 4,687 |
| Accumulated other comprehensive loss (Note 7) | **(1,360)** | (1,448) |
| **Controlling Interests** | **17,834** | 16,911 |
| Non-controlling interests | **1,812** | 1,425 |
| | **19,646** | 18,336 |
| | **50,883** | 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

| (unaudited - millions of Canadian $) | six months ended June 30 2013 | 2012 |
|---|---|---|
| **Common Shares** | | |
| Balance at beginning of period | **12,069** | 12,011 |
| Shares issued on exercise of stock options | **62** | 19 |
| Balance at end of period | **12,131** | 12,030 |
| **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 | **(4)** | - |
| Dilution impact from TC PipeLines, LP units issued | **29** | - |
| Balance at end of period | **404** | 380 |
| **Retained Earnings** | | |
| Balance at beginning of period | **4,687** | 4,628 |
| Net income attributable to controlling interests | **846** | 652 |
| Common share dividends | **(650)** | (620) |
| Preferred share dividends | **(37)** | (28) |
| Balance at end of period | **4,846** | 4,632 |
| **Accumulated Other Comprehensive Loss** | | |
| Balance at beginning of period | **(1,448)** | (1,449) |
| Other comprehensive income | **88** | 52 |
| Balance at end of period | **(1,360)** | (1,397) |
| **Equity Attributable to Controlling Interests** | **17,834** | 16,869 |
| **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 | **36** | 47 |
| Preferred share dividends of TCPL | **11** | 11 |
| Portland | **7** | 3 |
| Other comprehensive income attributable to non-controlling interests | **57** | 3 |
| Sale of TC PipeLines, LP units | | |
| Proceeds, net of issue costs | **384** | - |
| Decrease in TransCanada's ownership | **(47)** | - |
| Distributions to non-controlling interests | **(70)** | (68) |
| Foreign exchange and other | **9** | - |
| Balance at end of period | **1,812** | 1,461 |
| **Total Equity** | **19,646** | 18,330 |

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 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.

## 3. Segmented Information

| **three months ended June 30** | **Natural gas pipelines** | | **Oil pipelines** | | **Energy** | | **Corporate** | | **Total** | |
|---|---|---|---|---|---|---|---|---|---|---|
| (unaudited - millions of Canadian $) | **2013** | **2012** | **2013** | **2012** | **2013** | **2012** | **2013** | **2012** | **2013** | **2012** |
| Revenues | **1,031** | 1,034 | **278** | 251 | **700** | 562 | **-** | - | **2,009** | 1,847 |
| Income from equity investments | **29** | 37 | **-** | - | **124** | 28 | **-** | - | **153** | 65 |
| Plant operating costs and other | **(339)** | (330) | **(82)** | (68) | **(210)** | (214) | **(17)** | (15) | **(648)** | (627) |
| Commodity purchases resold | **-** | - | **-** | - | **(283)** | (208) | **-** | - | **(283)** | (208) |
| Property taxes | **(77)** | (75) | **(10)** | (7) | **(19)** | (18) | **-** | - | **(106)** | (100) |
| Depreciation and amortization | **(245)** | (234) | **(37)** | (36) | **(69)** | (72) | **(5)** | (4) | **(356)** | (346) |
| | **399** | 432 | **149** | 140 | **243** | 78 | **(22)** | (19) | **769** | 631 |
| Interest expense | | | | | | | | | **(252)** | (239) |
| Interest income and other | | | | | | | | | **(11)** | 5 |
| Income before Income Taxes | | | | | | | | | **506** | 397 |
| Income taxes expense | | | | | | | | | **(98)** | (85) |
| Net Income | | | | | | | | | **408** | 312 |
| Net Income Attributable to Non-Controlling Interests | | | | | | | | | **(23)** | (26) |
| **Net Income Attributable to Controlling Interests** | | | | | | | | | **385** | 286 |
| Preferred Share Dividends | | | | | | | | | **(20)** | (14) |
| **Net Income Attributable to Common Shares** | | | | | | | | | **365** | 272 |

| six months ended June 30 | Natural gas pipelines | | Oil pipelines | | Energy | | Corporate | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| (unaudited - millions of Canadian $) | **2013** | **2012** | **2013** | **2012** | **2013** | **2012** | **2013** | **2012** | **2013** | **2012** |
| Revenues | **2,188** | 2,119 | **549** | 510 | **1,524** | 1,163 | **-** | - | **4,261** | 3,792 |
| Income from equity investments | **69** | 83 | **-** | - | **177** | 42 | **-** | - | **246** | 125 |
| Plant operating costs and other | **(657)** | (657) | **(161)** | (137) | **(420)** | (381) | **(51)** | (44) | **(1,289)** | (1,219) |
| Commodity purchases resold | **-** | - | **-** | - | **(659)** | (421) | **-** | - | **(659)** | (421) |
| Property taxes | **(155)** | (154) | **(23)** | (24) | **(37)** | (37) | **-** | - | **(215)** | (215) |
| Depreciation and amortization | **(498)** | (466) | **(74)** | (72) | **(143)** | (145) | **(8)** | (7) | **(723)** | (690) |
| | **947** | 925 | **291** | 277 | **442** | 221 | **(59)** | (51) | **1,621** | 1,372 |
| Interest expense | | | | | | | | | **(510)** | (481) |
| Interest income and other | | | | | | | | | **2** | 36 |
| Income before Income Taxes | | | | | | | | | **1,113** | 927 |
| Income taxes expense | | | | | | | | | **(213)** | (214) |
| Net Income | | | | | | | | | **900** | 713 |
| Net Income Attributable to Non-Controlling Interests | | | | | | | | | **(54)** | (61) |
| Net Income Attributable to Controlling Interests | | | | | | | | | **846** | 652 |
| Preferred Share Dividends | | | | | | | | | **(35)** | (28) |
| **Net Income Attributable to Common Shares** | | | | | | | | | **811** | 624 |

### TOTAL ASSETS

| (unaudited - millions of Canadian $) | June 30, 2013 | December 31, 2012 |
|---|---|---|
| Natural Gas Pipelines | **24,322** | 23,210 |
| Oil Pipelines | **11,667** | 10,485 |
| Energy | **13,400** | 13,157 |
| Corporate | **1,494** | 1,481 |
| | **50,883** | 48,333 |

## 4. Income Taxes

At June 30, 2013, the total unrecognized tax benefit of uncertain tax positions was approximately $25 million (December 31, 2012 - $49 million). TransCanada recognizes interest and penalties related to income tax uncertainties in income tax expense. Included in net tax expense for the three and six months ended June 30, 2013 is nil and $1 million, respectively, of interest expense and nil for penalties (June 30, 2012 – nil and $1 million, respectively, of interest expense and nil for penalties). At June 30, 2013, the Company had $6 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 six-month periods ended June 30, 2013 and 2012 were 19 per cent and 23 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 six months ended June 30, 2013, TransCanada capitalized interest related to capital projects of $60 million and $115 million, respectively (June 30, 2012 - $76 million and $150 million, respectively).

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

In June 2013, TransCanada PipeLines Limited retired US$350 million of 4.00 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 under its November 2011 equity base shelf prospectus. 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 June 30, 2013**<br>(unaudited - millions of Canadian $) | **Before tax amount** | **Income tax recovery/(expense)** | **Net of tax amount** |
|---|---|---|---|
| Foreign currency translation gains and losses on investments in foreign operations | **170** | **55** | **225** |
| Change in fair value of net investment hedges | **(182)** | **47** | **(135)** |
| Change in fair value of cash flow hedges | **(68)** | **24** | **(44)** |
| Reclassification to net income of gains and losses on cash flow hedges | **18** | **(7)** | **11** |
| Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans | **7** | **(1)** | **6** |
| Other comprehensive loss on equity investments | **(3)** | **1** | **(2)** |
| Other comprehensive income | **(58)** | **119** | **61** |

| **three months ended June 30, 2012**<br>(unaudited - millions of Canadian $) | **Before tax amount** | **Income tax recovery/(expense)** | **Net of tax amount** |
|---|---|---|---|
| Foreign currency translation gains and losses on investments in foreign operations | 84 | 30 | 114 |
| Change in fair value of net investment hedges | (80) | 19 | (61) |
| Change in fair value of cash flow hedges | 43 | (15) | 28 |
| Reclassification to net income of gains and losses on cash flow hedges | 47 | (20) | 27 |
| Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans | 5 | (1) | 4 |
| Other comprehensive loss on equity investments | (3) | - | (3) |
| Other comprehensive income | 96 | 13 | 109 |

| **six months ended June 30, 2013**<br>(unaudited - millions of Canadian $) | **Before tax amount** | **Income tax recovery/(expense)** | **Net of tax amount** |
|---|---|---|---|
| Foreign currency translation gains and losses on investments in foreign operations | **247** | **89** | **336** |
| Change in fair value of net investment hedges | **(248)** | **64** | **(184)** |
| Change in fair value of cash flow hedges | **(30)** | **7** | **(23)** |
| Reclassification to net income of gains and losses on cash flow hedges | **11** | **(4)** | **7** |
| Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans | **17** | **(5)** | **12** |
| Other comprehensive loss on equity investments | **(4)** | **1** | **(3)** |
| Other comprehensive income | **(7)** | **152** | **145** |

| **six months ended June 30, 2012**<br>(unaudited - millions of Canadian $) | **Before tax amount** | **Income tax recovery/(expense)** | **Net of tax amount** |
|---|---|---|---|
| Foreign currency translation gains and losses on investments in foreign operations | (1) | 8 | 7 |
| Change in fair value of net investment hedges | (31) | 8 | (23) |
| Change in fair value of cash flow hedges | (36) | 19 | (17) |
| Reclassification to net income of gains and losses on cash flow hedges | 113 | (41) | 72 |
| Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans | 11 | 3 | 14 |
| Other comprehensive income on equity investments | 3 | (1) | 2 |
| Other comprehensive income | 59 | (4) | 55 |

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

| **three months ended June 30, 2013**<br>(unaudited - millions of Canadian $) | **Currency translation adjustments** | **Cash flow hedges** | **Pension and OPEB plan adjustments** | **Total[1]** |
|---|---|---|---|---|
| AOCI Balance at April 1, 2013 | **(665)** | **(95)** | **(624)** | **(1,384)** |
| Other comprehensive income before reclassifications[2] | **53** | **(45)** | **(1)** | **7** |
| Amounts reclassified from accumulated other comprehensive loss[3] | **-** | **11** | **6** | **17** |
| Net current period other comprehensive income/(loss) | **53** | **(34)** | **5** | **24** |
| **AOCI Balance at June 30, 2013** | **(612)** | **(129)** | **(619)** | **(1,360)** |

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 $37 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 $77 million ($50 million, net of tax) at June 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.

| **six months ended June 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 before reclassifications[2] | **95** | **(26)** | **-** | **69** |
| Amounts reclassified from accumulated other comprehensive loss[3] | **-** | **7** | **12** | **19** |
| Net current period other comprehensive income/(loss) | **95** | **(19)** | **12** | **88** |
| **AOCI Balance at June 30, 2013** | **(612)** | **(129)** | **(619)** | **(1,360)** |

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 $57 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 $77 million ($50 million, net of tax) at June 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 June 30, 2013** | **six months ended June 30, 2013** | |
| Cash flow hedges | | | |
| Power | **(14)** | **(3)** | Revenue (Energy) |
| Interest | **(4)** | **(8)** | Interest expense |
| | **(18)** | **(11)** | Total before tax |
| | **7** | **4** | Income tax expense |
| | **(11)** | **(7)** | Net of tax |
| Pension and other post-retirement plan adjustments | | | |
| Amortization of net loss[2] | **(7)** | **(17)** | Total before tax |
| | **1** | **5** | Income tax expense |
| | **(6)** | **(12)** | 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 June 30 | | | | six months ended June 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | Pension benefit plans | | Other post-retirement benefit plans | | Pension benefit plans | | Other post-retirement benefit plans | |
| (unaudited - millions of Canadian $) | **2013** | **2012** | **2013** | **2012** | **2013** | **2012** | **2013** | **2012** |
| Service cost | **22** | 17 | **-** | - | **41** | 33 | **1** | 1 |
| Interest cost | **23** | 24 | **2** | 2 | **47** | 47 | **4** | 4 |
| Expected return on plan assets | **(29)** | (29) | **(1)** | (1) | **(58)** | (57) | **(1)** | (1) |
| Amortization of actuarial loss | **6** | 4 | **-** | 1 | **15** | 9 | **1** | 1 |
| Amortization of past service cost | **1** | 1 | **-** | - | **1** | 1 | **-** | - |
| Amortization of regulatory asset | **8** | 5 | **1** | - | **15** | 10 | **1** | - |
| Amortization of transitional obligation related to regulated business | **-** | - | **1** | 1 | **-** | - | **1** | 1 |
| **Net benefit cost recognized** | **31** | 22 | **3** | 3 | **61** | 43 | **7** | 6 |

## 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 June 30, 2013, there were no significant amounts past due or impaired, and there were no significant credit losses during the year.

At June 30, 2013, the Company had a credit risk concentration of $263 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, forward foreign exchange contracts and foreign exchange options.

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

| (unaudited - billions of Canadian $) | **June 30, 2013** | **December 31, 2012** |
|---|---|---|
| Carrying value | **12.2 (US 11.7)** | 11.1 (US 11.2) |
| Fair value | **14.2 (US 13.5)** | 14.3 (US 14.4) |

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

| (unaudited - millions of Canadian $) | June 30, 2013 | December 31, 2012 |
|---|---|---|
| Other current assets | **30** | 71 |
| Intangible and other assets | **2** | 47 |
| Accounts payable and other | **52** | 6 |
| Other long-term liabilities | **146** | 30 |

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

| Asset/(liability)<br>(unaudited - millions of Canadian $) | June 30, 2013 | | December 31, 2012 | |
|---|---|---|---|---|
| | Fair Value[1] | Notional or principal amount | Fair value[1] | Notional or principal amount |
| U.S. dollar cross-currency swaps | | | | |
| (maturing 2013 to 2019)[2] | **(137)** | **US 3,900** | 82 | US 3,800 |
| U.S. dollar forward foreign exchange contracts | | | | |
| (maturing 2013 to 2014) | **(29)** | **US 1,050** | - | US 250 |
| | **(166)** | **US 4,950** | 82 | US 4,050 |

1 Fair values equal carrying values.
2 Net Income in the three and six months ended June 30, 2013 included net realized gains of $7 million and $14 million, respectively, (2012 - gains of $7 million and $14 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:

| (unaudited - millions of Canadian $) | June 30, 2013 | | December 31, 2012 | |
|---|---|---|---|---|
| | Carrying amount[1] | Fair value[2] | Carrying amount[1] | Fair value[2] |
| **Financial assets** | | | | |
| Cash and cash equivalents | **674** | **674** | 551 | 551 |
| Accounts receivable and other[3] | **1,301** | **1,350** | 1,288 | 1,337 |
| Available for sale assets | **47** | **47** | 44 | 44 |
| | **2,022** | **2,071** | 1,883 | 1,932 |
| **Financial liabilities**[4] | | | | |
| Notes payable | **2,900** | **2,900** | 2,275 | 2,275 |
| Accounts payable and other long-term liabilities[5] | **1,114** | **1,114** | 1,535 | 1,535 |
| Accrued interest | **380** | **380** | 368 | 368 |
| Long-term debt | **19,699** | **23,474** | 18,913 | 24,573 |
| Junior subordinated notes | **1,050** | **1,105** | 994 | 1,054 |
| | **25,143** | **28,973** | 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 June 30, 2013, financial assets of $1.1 billion (December 31, 2012 - $1.1 billion) are included in accounts receivable, $72 million (December 31, 2012 - $40 million) in other current assets and $225 million (December 31, 2012 - $240 million) in intangible and other assets.
4 Condensed consolidated statement of income in the three and six months ended June 30, 2013 included gains of $3 million and losses of $7 million, respectively, (2012 - gains of $3 million and losses of $12 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 June 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 June 30, 2013, financial liabilities of $1.1 billion (December 31, 2012 - $1.5 billion) are included in accounts payable and $36 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 | **$141** | **$70** | **$-** | **$11** |
| Liabilities | **$(183)** | **$(99)** | **$(17)** | **$(11)** |
| Notional values | | | | |
| Volumes[3] | | | | |
| Sales | **35,445** | **64** | **-** | **-** |
| Purchases | **34,750** | **102** | **-** | **-** |
| Canadian dollars | **-** | **-** | **-** | **620** |
| U.S. dollars | **-** | **-** | **US 1,274** | **US 200** |
| Net unrealized gains/(losses) in the period[4] | | | | |
| three months ended June 30, 2013 | **$5** | **$(21)** | **$(10)** | **$-** |
| six months ended June 30, 2013 | **$(3)** | **$(12)** | **$(16)** | **$-** |
| Net realized losses in the period[4] | | | | |
| three months ended June 30, 2013 | **$(29)** | **$(5)** | **$(6)** | **$-** |
| six months ended June 30, 2013 | **$(36)** | **$(7)** | **$(7)** | **$-** |
| Maturity dates | **2013-2017** | **2013-2016** | **2013-2014** | **2013-2016** |
| **Derivative instruments in hedging relationships**[5,6] | | | | |
| Fair values[2] | | | | |
| Assets | **$37** | **$-** | **$-** | **$7** |
| Liabilities | **$(103)** | **$(1)** | **$(1)** | **$-** |
| Notional values | | | | |
| Volumes[3] | | | | |
| Sales | **6,283** | **-** | **-** | **-** |
| Purchases | **13,206** | **-** | **-** | **-** |
| U.S. dollars | **-** | **-** | **US 15** | **US 200** |
| Cross-currency | **-** | **-** | **-** | **-** |
| Net realized (losses)/gains in the period[4] | | | | |
| three months ended June 30, 2013 | **$(84)** | **$(1)** | **$-** | **$2** |
| six months ended June 30, 2013 | **$(11)** | **$(1)** | **$-** | **$4** |
| Maturity dates | **2013-2018** | **2013** | **2014** | **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 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 six months ended June 30, 2013, net realized gains on fair value hedges were $2 million and $4 million, respectively and were included in interest expense. For the three and six months ended June 30, 2013, the Company did not record any amounts in net income related to ineffectiveness for fair value hedges.

6 For the three and six months ended June 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 (losses)/gains in the period[5] | | | | |
| three months ended June 30, 2012 | $(12) | $4 | $(14) | $- |
| six months ended June 30, 2012 | $(19) | $(10) | $(8) | $- |
| Net realized (losses)/gains in the period[5] | | | | |
| three months ended June 30, 2012 | $(6) | $(5) | $6 | $- |
| six months ended June 30, 2012 | $9 | $(15) | $15 | $- |
| 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 | - | - | - |
| Purchases | 15,184 | 1 | - | - |
| U.S. dollars | - | - | US 12 | US 350 |
| Cross-currency | - | - | 136/US 100 | - |
| Net realized (losses)/gains in the period[5] | | | | |
| three months ended June 30, 2012 | $(26) | $(8) | $- | $2 |
| six months ended June 30, 2012 | $(58) | $(14) | $- | $3 |
| 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 six months ended June 30, 2012 were $2 million and $4 million, respectively, and were included in Interest expense. In the three and six months ended June 30, 2012, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

7 For the three and six months ended June 30, 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 $) | June 30, 2013 | December 31, 2012 |
|---|---|---|
| **Current** | | |
| Other current assets | **187** | 259 |
| Accounts payable and other | **(341)** | (283) |
| **Long term** | | |
| Intangible and other assets | **111** | 187 |
| Other long-term liabilities | **(272)** | (186) |

## DERIVATIVES IN CASH FLOW HEDGING RELATIONSHIPS

The components of other comprehensive income (OCI) related to derivatives in cash flow hedging relationships are as follows:

| **Cash flow hedges[1]** **three months ended June 30** (unaudited – millions of Canadian $, pre-tax) | **Power** | | **Natural gas** | | **Foreign exchange** | | **Interest** | |
|---|---|---|---|---|---|---|---|---|
| | **2013** | **2012** | **2013** | **2012** | **2013** | **2012** | **2013** | **2012** |
| Change in fair value of derivative instruments recognized in OCI (effective portion) | **(70)** | 44 | **-** | (4) | **2** | 4 | **-** | - |
| Reclassification of gains and losses on derivative instruments from AOCI to net income (effective portion) | **12** | 28 | **2** | 15 | **-** | - | **4** | 4 |
| Gains and losses on derivative instruments recognized in earnings (ineffective portion) | **(2)** | 7 | **-** | 1 | **-** | - | **-** | - |

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

| **Cash flow hedges[1]** **six months ended June 30** (unaudited – millions of Canadian $, pre-tax) | **Power** | | **Natural gas** | | **Foreign exchange** | | **Interest** | |
|---|---|---|---|---|---|---|---|---|
| | **2013** | **2012** | **2013** | **2012** | **2013** | **2012** | **2013** | **2012** |
| Change in fair value of derivative instruments recognized in OCI (effective portion) | **(34)** | (22) | **-** | (14) | **4** | 1 | **-** | - |
| Reclassification of gains and losses on derivative instruments from AOCI to net income (effective portion) | **1** | 75 | **2** | 28 | **-** | - | **8** | 10 |
| Gains and losses on derivative instruments recognized in earnings (ineffective portion) | **(7)** | 1 | **-** | (1) | **-** | - | **-** | - |

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 June 30, 2013**<br>(unaudited - millions of Canadian $) | **Gross derivative instruments presented in the balance sheet** | **Amounts available for offset**[1] | **Net amounts** |
|---|---|---|---|
| Derivative - Asset | | | |
| Power | **178** | **(142)** | **36** |
| Natural gas | **70** | **(67)** | **3** |
| Foreign exchange | **32** | **(32)** | **-** |
| Interest | **18** | **(3)** | **15** |
| Total | **298** | **(244)** | **54** |
| Derivative - Liability | | | |
| Power | **(286)** | **142** | **(144)** |
| Natural gas | **(100)** | **67** | **(33)** |
| Foreign exchange | **(216)** | **32** | **(184)** |
| Interest | **(11)** | **3** | **(8)** |
| Total | **(613)** | **244** | **(369)** |

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

With respect to all financial arrangements, including the derivative instruments presented above, as at June 30, 2013, the Company had provided cash collateral of $201 million and letters of credit of $65 million to its counterparties. The Company held $1 million in cash collateral and $2 million in letters of credit on asset exposures at June 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**<br>(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 June 30, 2013, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $36 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 June 30, 2013, the Company would have been required to provide collateral of $36 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.<br><br>Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers.<br><br>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.<br><br>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.<br><br>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.<br><br>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)[1,2] | | Significant unobservable inputs (Level III)[2] | | Total | |
|---|---|---|---|---|---|---|---|---|
| (unaudited - millions of Canadian $, pre-tax) | Jun 30 2013 | Dec 31 2012 | Jun 30 2013 | Dec 31 2012 | Jun 30 2013 | Dec 31 2012 | Jun 30 2013 | Dec 31 2012 |
| Derivative instrument assets: | | | | | | | | |
| Power commodity contracts | **-** | - | **171** | 213 | **7** | 2 | **178** | 215 |
| Natural gas commodity contracts | **65** | 75 | **5** | 13 | **-** | - | **70** | 88 |
| Foreign exchange contracts | **-** | - | **32** | 119 | **-** | - | **32** | 119 |
| Interest rate contracts | **-** | - | **18** | 24 | **-** | - | **18** | 24 |
| Derivative Instrument Liabilities: | | | | | | | | |
| Power commodity contracts | **-** | - | **(279)** | (269) | **(7)** | (4) | **(286)** | (273) |
| Natural gas commodity contracts | **(85)** | (95) | **(15)** | (11) | **-** | - | **(100)** | (106) |
| Foreign exchange contracts | **-** | - | **(216)** | (76) | **-** | - | **(216)** | (76) |
| Interest rate contracts | **-** | - | **(11)** | (14) | **-** | - | **(11)** | (14) |
| Non-derivative financial instruments: | | | | | | | | |
| Available for sale assets | **-** | - | **47** | 44 | **-** | - | **47** | 44 |
| | **(20)** | (20) | **(248)** | 43 | **-** | (2) | **(268)** | 21 |

1 There were no transfers between Level I and Level II for the six months ended June 30, 2013 and 2012.
2 There were no transfers between Level II and Level III for the six months ended June 30, 2013 and 2012.

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

| | Derivatives[1] | | | |
|---|---|---|---|---|
| | three months ended June 30 | | six months ended June 30 | |
| (unaudited - millions of Canadian $, pre-tax) | 2013 | 2012 | 2013 | 2012 |
| Balance at beginning of period | **1** | (11) | **(2)** | (15) |
| Settlements | **1** | (1) | **1** | (1) |
| Transfers out of Level III | **(1)** | 1 | **(1)** | 1 |
| Total (losses)/gains included in OCI | **(1)** | 18 | **2** | 22 |
| Balance at end of period | **-** | 7 | **-** | 7 |

1 For the three and six months ended June 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 $5 million decrease or increase, respectively, in the fair value of outstanding derivative instruments included in Level III as at June 30, 2013.

## 10. Acquisition

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

## 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 six 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 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 June 30, 2013**<br>(unaudited - millions of Canadian $) | **Term** | **Potential Exposure**[1] | **Carrying Value** |
|---|---|---|---|
| Bruce Power | ranging to 2019[2] | **713** | **9** |
| Other jointly owned entities | ranging to 2040 | **41** | **9** |
| | | **754** | **18** |

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

## 12. Subsequent Events

On July 2, 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 closing adjustments for working capital of $17 million. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively.

In July 2013, TransCanada 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, TransCanada issued $450 million of ten-year and $300 million of 30-year senior notes maturing on July 19, 2023 and November 15, 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 July 2018.