QuarterlyReport to Shareholders

TransCanada
In business to deliver

TransCanada Reports First Quarter Results, Continues to Advance $25 Billion Portfolio of Projects

Calgary, Alberta – **April 26, 2013** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced net income attributable to common shares for first quarter 2013 of $446 million or $0.63 per share. The first quarter financial results include the impact of the National Energy Board (NEB) decision received in the period on our Canadian Restructuring Proposal. In the decision, among other items, the NEB approved a return on equity for the Canadian Mainline of 11.50 per cent for the years 2012 to 2017 compared to the last approved return on equity of 8.08 per cent. As a result, net income includes $84 million or $0.12 per share related to 2012. Excluding this and certain other minor amounts, comparable earnings were $370 million or $0.52 per share. Our Board of Directors also declared a quarterly dividend of $0.46 per common share for the quarter ending June 30, 2013, equivalent to $1.84 per share on an annualized basis.

"Our three business segments performed well during the first quarter," said Russ Girling, TransCanada's president and chief executive officer. "The restart of Bruce Power Units 1 and 2, the completion of the Bruce Power Unit 4 life extension outage in April, the return to service of Sundance A this fall and a higher Canadian Mainline return on equity are all expected to have a positive impact on earnings in 2013. At the same time, we continue to progress our $25 billion portfolio of commercially secured projects and advance other value creating opportunities including the Energy East Pipeline Project which would transport crude oil from western receipt points to eastern Canadian markets."

Over the next three years, subject to required approvals, we expect to complete $12 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 Tamazunchale Pipeline Extension, the acquisition of nine Ontario Solar projects, and the 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)

- First quarter financial results
  - Net income attributable to common shares of $446 million or $0.63 per share
  - Comparable earnings of $370 million or $0.52 per share
  - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.2 billion
  - Funds generated from operations of $916 million
- Declared a quarterly dividend of $0.46 per common share for the quarter ending June 30
- Received NEB decision on our Canadian Restructuring Proposal
- Bruce Power Units 1 and 2 now able to operate at full power and Unit 4 returned to service on April 13, 2013
- Continued to advance several growth initiatives in the Oil Pipelines business
  - Construction on the US$2.3 billion Gulf Coast Project, excluding the Houston Lateral, is now 70 per cent complete
  - Received the Draft Supplemental Environmental Impact Statement for the Keystone XL Pipeline from the U.S. Department of State (DOS)
  - Announced the launch of an open season for the Energy East Pipeline project to obtain firm commitments to transport crude oil from western receipt points to eastern Canadian markets

Comparable earnings for first quarter 2013 were $370 million or $0.52 per share compared to $363 million or $0.52 per share for the same period in 2012. Higher earnings contributions from the Canadian Mainline in the first quarter 2013 as a result of the NEB decision on its Restructuring Proposal, Bruce Power and U.S. Power, were offset by lower contributions from U.S. Natural Gas Pipelines and Western Power.

Net income attributable to common shares for first quarter 2013 was $446 million or $0.63 per share compared to $352 million or $0.50 per share in first 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 70 per cent complete and we estimate the total cost of the facilities to be US$2.3 billion.

  Construction of the 76 kilometre (km) (47 mile) Houston Lateral to transport crude oil to Houston refineries is expected to begin in mid 2013 and be complete by mid 2014 at a total cost of approximately US$300 million.

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

- *Keystone XL:* 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 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 is in the process of reviewing comments on the impact statement that it received during a 45 day public comment period that ended on April 22, 2013. Once the DOS has completed its review, it is anticipated that it will issue a Final Supplemental Environmental Impact Statement and then consult with other governmental agencies during a National Interest Determination period of up to 90 days, before making a decision on our Presidential Permit application.

  Due to ongoing delays in the issuance of a Presidential Permit for Keystone XL, we now expect the pipeline to be in service in the second half of 2015 and, based on our pipeline construction experience, the US$5.3 billion cost estimate will increase depending on the timing of the permit. As of March 31, 2013, we had invested US$1.8 billion in the project.

- *Energy East Pipeline:* We announced in April 2013 that we are holding an open season to obtain firm commitments for a pipeline to transport crude oil from western receipt points to eastern Canadian markets. The open season, which follows a successful expression of interest phase and discussions with prospective shippers, began on April 15, 2013 and closes on June 17, 2013.

  The Energy East Pipeline project involves converting natural gas pipeline capacity in approximately 3,000 km (1,864 miles) of our existing Canadian Mainline to crude oil service and constructing up to approximately 1,400 km (870 miles) of new pipeline. Subject to the results of the open season, the project will have the capacity to transport as much as 850,000 bbl/d, increasing access to eastern Canadian markets.

  We have begun Aboriginal and stakeholder engagement and field work as part of our initial design and planning. If the open season is successful, we will apply for regulatory approval to build and operate the facilities, with a potential in service date of late 2017.

- *Northern Courier Pipeline:* The Fort Hills Energy Limited Partnership has not indicated that their recent decision to cancel the Voyageur upgrader project has changed their current plans for Northern Courier. We have nearly completed the field work and Aboriginal and stakeholder engagement necessary to allow us to file the permit application with the Energy Resources Conservation Board and expect to file the application in second quarter 2013.

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 NEB approved several of our proposed changes, including the Canadian Mainline's revenue requirement for 2011 and 2012. At the same time, the NEB agreed with us that the Canadian Mainline has been significantly affected by market forces with the result that throughput has decreased significantly, and as a result, the Canadian Mainline tolls have increased over a short period of time eroding the Canadian Mainline's competitiveness. The response of the NEB was to adopt a multi-year fixed tolls approach which it believes will provide shippers with greater toll certainty and stability. Under the decision, long-term firm tolls are fixed through 2017 (subject to being re-opened under certain circumstances) at what the NEB determined is a competitive level. Although long-term firm tolls are fixed, the Canadian Mainline has been given pricing discretion for interruptible and short-term firm services. The NEB concluded in the decision that this framework will provide us with reasonable opportunity to recover our costs, over a reasonable period of time. Under or over collection variances to the revenue requirement inclusive of the return on and of capital will be carried over in deferral accounts to be dealt with in future NEB proceedings in 2017 (or earlier under certain circumstances). At that time, the NEB will determine how any variances contained in the deferral accounts will be addressed and the extent of cost disallowances, if any. As a result of the multi-year fixed tolls and increased risk associated with fluctuations in cash flow, the NEB increased the allowed return to 11.50 per cent on a 40 per cent equity ratio.

  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. We have determined that we will seek regulatory and potentially legal review and variance of certain aspects of the decision.

- *NGTL System:* The Alberta System is now known as the NGTL System to better reflect the service provided and continued growth in British Columbia (B.C.).

  We have been continuing our expansion of the NGTL System and have placed approximately $340 million of new facilities into service to date in 2013. We have applied and received approval from the NEB for an additional $300 million of facilities with in service dates planned for later in 2013. The NEB has also recommended approval of the Chinchaga lateral, an approximate $100 million project that is planned to be placed in service in early 2014. To date in 2013, we have applied for an additional $60 million of facilities and are planning regulatory applications for further expansion into B.C., which we estimate will cost between $1.0 billion and $1.5 billion to accommodate the Prince Rupert Gas Transmission Project.

- *Prince Rupert Gas Transmission Project:* We signed the project development agreement for the Prince Rupert Gas Transmission Project with Progress Energy Canada Ltd. in February 2013 and are now working to initiate the environmental assessment process, including developing and filing the project description that we plan to submit to the B.C. Environmental Assessment Office and the Canadian Environmental Assessment Agency (CEAA) in second quarter 2013.

- *Coastal GasLink:* 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. We expect to begin an NGTL open season to provide delivery service to Vanderhoof, B.C. on Coastal GasLink in second quarter 2013.

- *Tamazunchale Pipeline Extension Project:* A variety of construction activities are underway and the project remains on schedule to meet the planned in service date of first quarter 2014.

Energy:

- *Bruce Power:* The availability percentage for Units 1 and 2 increased through first quarter 2013. These units are now able to operate at full power. As Units 1 and 2 have not operated for an extended period of time they may experience slightly higher forced outage rates and reduced availability percentages in 2013.

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.

The overall plant availability percentage in 2013 is expected to be in the mid 80 per cent range for Bruce A and the high 80 per cent range for Bruce B. Planned maintenance outages on two of the Bruce B units and one of the Bruce A units are expected to be completed in second quarter 2013.

On April 5, 2013, Bruce Power announced that it had reached an agreement with the Ontario Power Authority (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.

- *Ontario Solar:* In late 2011, we agreed to buy nine Ontario solar projects with a combined capacity of 86 megawatts (MW) from Canadian Solar Solutions Inc. We expect to close the acquisition of the first three projects (combined capacity of 29 MW) by mid 2013 for a total cost of approximately $175 million. We expect to acquire the remaining six projects later in 2013 and 2014, subject to regulatory approvals.

Corporate:

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

- In March 2013, we completed a public offering of 24 million Series 7 cumulative redeemable first preferred shares. The Series 7 shares were issued at a price of $25 per share, resulting in gross proceeds of $600 million. The initial dividend rate is fixed to April 30, 2019 at $1.00 per share per annum paid quarterly.

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

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

Teleconference – Audio and Slide Presentation:

We will hold a teleconference and webcast on Friday, April 26, 2013 to discuss our first 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 1:00 p.m. (MDT) / 3:00 p.m. (EDT).

Analysts, members of the media and other interested parties are invited to participate by calling 866.226.1793 or 416.340.2218 (Toronto area). Please dial in 10 minutes prior to the start of the call. No pass code is required. A live webcast of the teleconference will be available at www.transcanada.com.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (EDT) May 3, 2013. Please call 800.408.3053 or 905.694.9451 and enter pass code 6260206.

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", "would", "believe", "may", "will", "plan", "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 financial and operational plans and outlook. All forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this news release, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to update or revise any forward-looking information except as required by law. For additional information on the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, refer to TransCanada's Quarterly Report to Shareholders dated April 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 may therefore not be comparable to similar measures presented by other companies. These non-GAAP measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable. For more information on non-GAAP measures, refer to TransCanada's Quarterly Report to Shareholders dated April 25, 2013.

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Quarterly report to shareholders
First quarter 2013

Financial highlights

Comparable EBITDA, 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 March 31 (unaudited - millions of $, except per share amounts)	2013	2012
Income		
Revenue	**2,252**	1,945
Comparable EBITDA	**1,168**	1,113
Net income attributable to common shares	**446**	352
per common share - basic	**$0.63**	$0.50
Comparable earnings	**370**	363
per common share	**$0.52**	$0.52
Operating cash flow		
Funds generated from operations	**916**	871
Increase in working capital	**(210)**	(169)
Net cash provided by operations	**706**	702
Investing activities		
Capital expenditures	**929**	464
Equity investments	**32**	216
Dividends		
Per common share	**$0.46**	$0.44
Basic common shares outstanding (millions)		
Average for the period	**706**	704
End of period	**706**	704

Management's discussion and analysis

April 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 quarter ended March 31, 2013, and should be read with the accompanying unaudited condensed consolidated financial statements for the quarter ended March 31, 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 comparative 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 April 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
- 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 and changes 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 U.S. Securities and Exchange Commission (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 may not 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.

We calculate comparable earnings by excluding the unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives 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 March 31 (unaudited - millions of $, except per share amounts)	2013	2012
Comparable EBITDA	**1,168**	1,113
Comparable depreciation and amortization	**(354)**	(344)
Comparable EBIT	**814**	769
Other income statement items		
Comparable interest expense	**(257)**	(242)
Comparable interest income and other	**18**	25
Comparable income taxes	**(159)**	(140)
Net income attributable to non-controlling interests	**(31)**	(35)
Preferred share dividends	**(15)**	(14)
Comparable earnings	**370**	363
Specific items (net of tax):		
Canadian restructuring proposal - 2012	**84**	-
Risk management activities[1]	**(8)**	(11)
Net income attributable to common shares	**446**	352
Comparable depreciation and amortization	**(354)**	(344)
Specific item:		
Canadian restructuring proposal - 2012	**(13)**	-
Depreciation and amortization	**(367)**	(344)
Comparable interest expense	**(257)**	(242)
Specific item:		
Canadian restructuring proposal - 2012	**(1)**	-
Interest expense	**(258)**	(242)
Comparable interest income and other	**18**	25
Specific items:		
Canadian restructuring proposal - 2012	**1**	-
Risk management activities[1]	**(6)**	6
Interest income and other	**13**	31
Comparable income taxes	**(159)**	(140)
Specific items:		
Canadian restructuring proposal - 2012	**42**	-
Risk management activities[1]	**2**	11
Income taxes expense	**(115)**	(129)
Comparable earnings per common share	**$0.52**	$0.52
Specific items (net of tax):		
Canadian restructuring proposal - 2012	**0.12**	-
Risk management activities[1]	**(0.01)**	(0.02)
Net income per common share	**$0.63**	$0.50

[1]

three months ended March 31 (unaudited - millions of $)	2013	2012
Canadian Power	**(2)**	(2)
U.S. Power	**1**	(32)
Natural Gas Storage	**(3)**	6
Foreign exchange	**(6)**	6
Income taxes attributable to risk management activities	**2**	11
Total losses from risk management activities	**(8)**	(11)

EBITDA and EBIT by business segment

three months ended March 31, 2013 (unaudited - millions of $)	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	**746**	**179**	**277**	**(34)**	**1,168**
Comparable depreciation and amortization	**(240)**	**(37)**	**(74)**	**(3)**	**(354)**
Comparable EBIT	**506**	**142**	**203**	**(37)**	**814**

three months ended March 31, 2012 (unaudited - millions of $)	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	725	173	244	(29)	1,113
Comparable depreciation and amortization	(232)	(36)	(73)	(3)	(344)
Comparable EBIT	493	137	171	(32)	769

Results - first quarter 2013

Net income attributable to common shares was $446 million this quarter compared to $352 million in first quarter 2012. This included $104 million of net income resulting from the National Energy Board's (NEB) decision on the Canadian Mainline Business and Services Restructuring Proposal and 2012 and 2013 Mainline Final Tolls Application (Canadian Restructuring Proposal). Of this amount, $84 million is excluded from comparable earnings as it relates to 2012.

Comparable earnings this quarter were $370 million or $0.52 per share, $7 million higher than first quarter 2012.

This was the result of:
- higher net income from the Canadian Mainline because of the first quarter 2013 impact of the NEB's decision on the Canadian Restructuring Proposal
- higher equity income from Bruce Power because of incremental earnings from Units 1 and 2 and the recognition of an insurance recovery partly offset by an increase in outage days
- higher realized power prices from U.S. Power.

These were partly offset by:
- lower contributions from U.S. natural gas pipelines
- lower earnings from Western Power because of the Sundance A PPA force majeure and lower realized prices
- 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.

Comparable earnings do not include net unrealized after-tax losses resulting from changes in the fair value of certain risk management activities:
- $8 million ($10 million before tax) in first quarter 2013
- $11 million ($22 million before tax) in first quarter 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 we included in our 2012 Annual Report. The NEB approved a return on equity (ROE) of 11.50 per cent on 40 per cent deemed common equity ratio, multi year tolls until 2017 and a new incentive mechanism. 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 March 31 (unaudited - millions of $)	**2013**	**2012**
Canadian Pipelines		
Canadian Mainline	**280**	250
NGTL System	**182**	177
Foothills	**29**	31
Other Canadian (TQM[1], Ventures LP)	**6**	8
Canadian Pipelines - comparable EBITDA	**497**	466
Comparable depreciation and amortization[2]	**(184)**	(177)
Canadian Pipelines - comparable EBIT	**313**	289
U.S. and International *(in US$)*		
ANR	**90**	97
GTN[3]	**28**	30
Great Lakes[4]	**10**	18
TC PipeLines, LP[1,5]	**17**	20
Other U.S. pipelines (Iroquois[1], Bison[3], Portland[6])	**43**	34
International (Gas Pacifico/INNERGY[1], Guadalajara, Tamazunchale, TransGas[1])	**26**	28
General, administrative and support costs	**(2)**	(2)
Non-controlling interests[7]	**43**	45
U.S. Pipelines and International - comparable EBITDA	**255**	270
Comparable depreciation and amortization[2]	**(55)**	(55)
U.S. Pipelines and International - comparable EBIT	**200**	215
Foreign exchange	**2**	-
U.S. Pipelines and International - comparable EBIT *(Cdn$)*	**202**	215
Business Development comparable EBITDA and EBIT	**(9)**	(11)
Natural Gas Pipelines - comparable EBIT	**506**	493
Summary		
Natural Gas Pipelines - comparable EBITDA	**746**	725
Comparable depreciation and amortization[2]	**(240)**	(232)
Natural Gas Pipelines - comparable EBIT	**506**	493

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 Represents our 33.3 per cent direct ownership interest of TC PipeLines, LP and our effective ownership through TC PipeLines, LP of 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.
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 March 31 (millions of $)	**2013**	**2012**
Canadian Mainline - net income	**151**	47
Canadian Mainline - comparable earnings	**67**	47
NGTL System	**56**	48
Foothills	**4**	5

OPERATING STATISTICS - WHOLLY OWNED CANADIAN PIPELINES

three months ended March 31	**Canadian Mainline**[1]		**NGTL System**[2]		**ANR**[3]	
(unaudited)	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Average investment base (millions of dollars)	**5,870**	5,812	**5,824**	5,282	**n/a**	n/a
Delivery volumes (Bcf)						
Total	**426**	430	**994**	998	**465**	482
Average per day	**4.7**	4.7	**11.0**	11.0	**5.2**	5.3

1 Canadian Mainline's throughput volumes represent physical deliveries to domestic and export markets. Physical receipts originating at the Alberta border and in Saskatchewan for the three months ended March 31, 2013 were 231 Bcf (2012 – 247 Bcf). Average per day was 2.6 Bcf (2012 – 2.7 Bcf).

2 Field receipt volumes for the NGTL System for the three months ended March 31, 2013 were 916 Bcf (2012 – 948 Bcf). Average per day was 10.2 Bcf (2012 – 10.4 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.

Net income for the Canadian Mainline this quarter was $104 million higher than first quarter 2012 because of the impact of the NEB's March 27, 2013 decision on the Canadian Restructuring Proposal. Among other things, the NEB approved an ROE of 11.50 per cent on a 40 per cent deemed common equity effective for the years 2012 to 2017 compared to the last approved ROE of 8.08 per cent on a 40 per cent deemed common equity which was used to record earnings in 2012. Comparable earnings in first quarter 2013 excludes $84 million related to the 2012 impact of the NEB decision.

Net income for the NGTL System (formerly known as the Alberta System) was $8 million higher than first quarter 2012 because of a higher average investment base and termination of the annual fixed operating, maintenance and administration (OM&A) costs component included in the 2010 - 2012 Revenue Requirement which expired at the end of 2012. The NGTL System's results this quarter reflected 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$255 million this quarter, or US$15 million lower than first quarter 2012. This was the net effect of:

- lower revenue at Great Lakes because of lower rates and uncontracted capacity
- higher costs at ANR relating to services provided by other pipelines
- higher short term and interruptible revenues at Portland.

COMPARABLE DEPRECIATION AND AMORTIZATION

Comparable depreciation and amortization was $8 million higher this quarter than in first quarter 2012 mainly because of the higher rate base on the NGTL System.

Oil Pipelines

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

three months ended March 31 (unaudited - millions of $)	**2013**	**2012**
Keystone Pipeline System	**186**	174
Oil Pipeline Business Development	**(7)**	(1)
Oil Pipelines - comparable EBITDA	**179**	173
Comparable depreciation and amortization	**(37)**	(36)
Oil Pipelines - comparable EBIT	**142**	137
Comparable EBIT denominated as follows:		
Canadian dollars	**47**	48
U.S. dollars	**94**	89
Foreign exchange	**1**	-
	142	137

Comparable EBITDA for the Keystone Pipeline System was $12 million higher this quarter than in first quarter 2012. This increase 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 this quarter were $6 million higher than in first quarter 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 March 31 (unaudited - millions of $)	2013	2012
Canadian Power		
Western Power[1]	**79**	131
Eastern Power[1,2]	**95**	93
Bruce Power[1]	**31**	(13)
General, administrative and support costs	**(10)**	(11)
Canadian Power - comparable EBITDA[1]	**195**	200
Comparable depreciation and amortization[3]	**(43)**	(40)
Canadian Power - comparable EBIT[1]	**152**	160
U.S. Power *(US$)*		
Northeast Power	**77**	46
General, administrative and support costs	**(10)**	(10)
U.S. Power - comparable EBITDA	**67**	36
Comparable depreciation and amortization	**(28)**	(30)
U.S. Power - comparable EBIT	**39**	6
Foreign exchange	**1**	-
U.S. Power - comparable EBIT *(Cdn$)*	**40**	6
Natural Gas Storage		
Alberta Storage	**20**	15
General, administrative and support costs	**(2)**	(2)
Natural Gas Storage - comparable EBITDA[1]	**18**	13
Comparable depreciation and amortization[3]	**(3)**	(3)
Natural Gas Storage - comparable EBIT[1]	**15**	10
Business Development comparable EBITDA and EBIT	**(4)**	(5)
Energy - comparable EBIT[1]	**203**	171
Summary		
Energy - comparable EBITDA[1]	**277**	244
Comparable depreciation and amortization[3]	**(74)**	(73)
Energy - comparable EBIT[1]	**203**	171

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 Cartier phase two of Gros-Morne starting in November 2012.
3 Does not include depreciation and amortization of equity investments.

Comparable EBITDA for Energy was $277 million this quarter, or $33 million higher than first quarter 2012. This was the net effect of:

- higher equity income from Bruce Power because of incremental earnings from Units 1 and 2, which were returned to service in October 2012, the recognition of a business interruption insurance recovery and a Unit 3 outage in first quarter 2012 partially offset by the extended outage of Unit 4 in first quarter 2013
- higher earnings from U.S. Power mainly because of higher realized power prices

- lower earnings from Western Power because of the Sundance A PPA force majeure and lower realized power prices.

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 March 31 (unaudited - millions of $)	2013	2012
Revenue		
Western power	**142**	224
Eastern power[1]	**109**	103
Other[2]	**31**	25
	282	352
Income from equity investments[3]	**22**	23
Commodity purchases resold		
Western power	**(65)**	(94)
Other[4]	**(2)**	(2)
	(67)	(96)
Plant operating costs and other	**(63)**	(55)
General, administrative and support costs	**(10)**	(11)
Comparable EBITDA	**164**	213
Comparable depreciation and amortization[5]	**(43)**	(40)
Comparable EBIT	**121**	173

1 Includes Cartier phase two of Gros-Morne starting in November 2012.
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.

three months ended March 31 (unaudited)	2013	2012
Sales volumes (GWh)		
Supply		
Generation		
Western Power	**670**	671
Eastern Power[1]	**1,346**	1,143
Purchased		
Sundance A & B and Sheerness PPAs[2]	**1,707**	2,039
Other purchases	**-**	45
	3,723	3,898
Sales		
Contracted		
Western Power	**1,707**	2,295
Eastern Power[1]	**1,346**	1,143
Spot		
Western Power	**670**	460
	3,723	3,898
Plant availability[3]		
Western Power[4]	**97%**	99%
Eastern Power[1,5]	**96%**	93%

1 Includes Cartier phase two of Gros-Morne starting in November 2012.
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 was $79 million this quarter, or $52 million lower than first quarter 2012. Revenue also decreased by $82 million this quarter to $142 million. These decreases were mainly due to:

- the Sundance A PPA force majeure
- lower realized power prices and
- lower purchased PPA volumes during periods of lower spot 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 Energy - Significant Events in the MD&A in our 2012 Annual Report for more information about the Sundance A PPA arbitration decision.

Average spot market power prices in Alberta were $64 per MWh this quarter, compared to $60 per MWh in first quarter 2012. This increase was mainly the result of high spot market prices in the month of March driven by plant outages and increased demand. Western Power's average realized power price this quarter was lower than first quarter 2012 because of contracting activities. Purchased volumes were lower than first quarter 2012 mainly because of lower utilization of the Sheerness and Sundance B PPAs and higher Sundance B plant outage days.

Western Power's commodity purchases resold were $65 million this quarter, or $29 million lower than first quarter 2012, because of the Sundance A PPA force majeure and lower purchased volumes during periods of lower spot prices.

Eastern Power's comparable EBITDA of $95 million was $2 million higher than first quarter 2012 because of the start up of phase two of Cartier Gros-Morne in November 2012, partially offset by lower contractual earnings at Bécancour.

Plant operating costs and other, which includes natural gas fuel consumed in power generation, were $63 million this quarter, or $8 million higher than first quarter 2012, mainly due to higher natural gas fuel prices in 2013.

Approximately 72 per cent of Western Power sales volumes were sold under contract this quarter, compared to 83 per cent in first quarter 2012. To reduce exposure to spot market prices in Alberta, Western Power has entered into fixed-price power sales contracts to sell approximately 5,300 GWh for the remainder of 2013 and approximately 5,200 GWh in 2014.

BRUCE POWER

Our proportionate share

three months ended March 31 (unaudited - millions of $ unless noted otherwise)	2013	2012
Income/(loss) from equity investments[1]		
Bruce A	**36**	(33)
Bruce B	**(5)**	20
	31	(13)
Comprised of:		
Revenues	**287**	162
Operating expenses	**(173)**	(135)
Depreciation and other	**(83)**	(40)
	31	(13)
Bruce Power - Other information		
Plant availability[2]		
Bruce A[3]	**66%**	48%
Bruce B	**78%**	86%
Combined Bruce Power	**72%**	62%
Planned outage days		
Bruce A	**90**	91
Bruce B	**70**	46
Unplanned outage days		
Bruce A	**8**	-
Bruce B	**9**	4
Sales volumes (GWh)[1]		
Bruce A[3]	**2,097**	747
Bruce B	**1,735**	1,909
	3,832	2,656
Realized sales price per MWh		
Bruce A	**$68**	$66
Bruce B[4]	**$53**	$54
Combined Bruce Power	**$59**	$57

1 Represents our 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B.
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 Includes revenues under the floor price mechanism, revenues from contract settlements and volumes and revenues associated with deemed generation.

Equity income from Bruce A increased by $69 million this quarter, compared to first quarter 2012. The increase was due to:

- incremental earnings from Units 1 and 2 which returned to service in October 2012
- recognition 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
- higher earnings from Unit 3 due to the West Shift Plus planned outage during first quarter 2012.

These increases were partially offset by the impact of the Unit 4 planned outage which began in August 2012 and was completed April 13, 2013.

The availability percentage for Units 1 and 2 increased through first quarter 2013 with an average availability in the mid 80s. These units are now able to operate at full power; however, as Units 1 and 2 have not operated for an extended period of time they may experience slightly higher forced outage rates and reduced availability percentages in 2013.

Equity loss from Bruce B was $5 million this quarter, compared to equity income of $20 million in first quarter 2012. The decrease was mainly due to lower volumes and higher operating costs resulting from higher planned outage days.

Under the contract with the Ontario Power Authority (OPA), all of the output from Bruce A is sold at a fixed price per MWh, adjusted annually for inflation on April 1. Bruce A also recovers fuel costs from the OPA.

Bruce A Fixed price	**Per MWh**
April 1, 2013 - March 31, 2014	$69.19
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 recorded in revenues in first quarter 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. Planned maintenance on two of the Bruce B units and one of the Bruce A units is expected to be completed in second quarter 2013.

U.S. POWER

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

three months ended March 31 (unaudited - millions of US $)	2013	2012
Revenue		
Power[1]	**433**	195
Capacity	**47**	40
Other[2]	**29**	19
	509	254
Commodity purchases resold	**(306)**	(117)
Plant operating costs and other[2]	**(126)**	(91)
General, administrative and support costs	**(10)**	(10)
Comparable EBITDA	**67**	36
Comparable depreciation and amortization	**(28)**	(30)
Comparable EBIT	**39**	6

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 March 31 (unaudited)	2013	2012
Physical sales volumes (GWh)		
Supply		
Generation	**1,051**	1,154
Purchased	**2,479**	1,570
	3,530	2,724
Plant availability[1]	**79%**	80%

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

U.S. Power's comparable EBITDA was US$67 million this quarter, or US$31 million higher than first quarter 2012. This was 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 in both New York and New England were significantly higher this quarter than first quarter 2012. The combination of higher natural gas prices, pipeline constraints and an increase in demand for natural gas resulted in higher spot power prices this quarter.

Physical sales volumes this quarter were higher than the same period 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 lower, mainly due to lower generation in New England partly offset by higher Ravenswood generation.

Power revenue was US$433 million this quarter, or US$238 million higher than first quarter 2012. This was mainly because of the combination of higher realized power prices and higher sales volumes to wholesale, commercial and industrial customers.

Capacity revenue was US$47 million this quarter, or US$7 million higher than first quarter 2012. A two per cent increase in New York Zone J 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$306 million this quarter, or US$189 million higher than first quarter 2012 because we purchased higher volumes of power at higher prices to fulfill increased power sales commitments to wholesale, commercial and industrial customers.

Plant operating costs and other, which includes fuel gas consumed in generation, was US$126 million this quarter, or US$35 million higher than first quarter 2012 because of higher natural gas fuel prices.

As at March 31, 2013, approximately 2,600 GWh or 41 per cent of U.S. Power's planned generation is contracted for 2013, and 2,400 GWh or 27 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 March 31 (unaudited - millions of $)	**2013**	**2012**
Alberta Storage	**20**	15
General, administrative and support costs	**(2)**	(2)
Comparable EBITDA	**18**	13
Comparable depreciation and amortization	**(3)**	(3)
Comparable EBIT	**15**	10

Comparable EBITDA was $18 million this quarter, or $5 million higher than first quarter 2012, mainly due to higher earnings from CrossAlta resulting from the acquisition of the remaining 40 per cent interest in December 2012. The seasonal nature of natural gas storage generally results in higher revenues in the winter season.

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 NEB approved several of our proposed changes, including the Canadian Mainline's revenue requirement for 2011 and 2012. At the same time, the NEB agreed with us that the Canadian Mainline has been significantly affected by market forces with the result that throughput has decreased significantly, and as a result, the Canadian Mainline tolls have increased over a short period of time eroding the Canadian Mainline's competitiveness. The response of the NEB was to adopt a multi-year fixed tolls approach which it believes will provide shippers with greater toll certainty and stability. Under the decision, long-term firm tolls are fixed through 2017 (subject to being re-opened under certain circumstances) at what the NEB determined is a competitive level. Although long-term firm tolls are fixed, the Canadian Mainline has been given pricing discretion for interruptible and short-term firm services. The NEB concluded in the decision that this framework will provide us with reasonable opportunity to recover our costs, over a reasonable period of time. Under or over collection variances to the revenue requirement inclusive of the return on and of capital will be carried over in deferral accounts to be dealt with in future NEB proceedings in 2017 (or earlier under certain circumstances). At that time, the NEB will determine how any variances contained in the deferral accounts will be addressed and the extent of cost disallowances, if any. As a result of the multi-year fixed tolls and increased risk associated with fluctuations in cash flow, the NEB increased the allowed return to 11.50 per cent on 40 per cent equity ratio.

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. We have determined that we will seek regulatory and potentially legal review and variance of certain aspects of the decision.

NGTL System

The Alberta System is now known as the NGTL System to better reflect the service provided and continued growth in British Columbia.

Our application to contract for capacity on the Canadian Mainline and Foothills Pipelines was denied as part of the NEB's decision regarding the Canadian Restructuring Proposal. Therefore, the location of our export delivery will remain at Empress and the Alberta/BC border.

NGTL System expansion projects

We have been continuing our expansion of the NGTL System and have placed approximately $340 million of new facilities into service to date in 2013. We have applied and received approval from the NEB for an additional $300 million of new facilities with in-service dates planned for later in 2013. The NEB has also recommended approval for the Chinchaga lateral, an approximate $100 million project, that is planned to be placed in service in early 2014. To date in 2013, we have applied for an additional $60 million of facilities and are planning regulatory applications for further expansion into B.C. which we estimate will cost between $1.0 billion and $1.5 billion to accommodate the Prince Rupert Gas Transmission Project.

Prince Rupert Gas Transmission Project

We signed the project development agreement for the Prince Rupert Gas Transmission Project with Progress Energy Canada Ltd. in February 2013 and are now working to initiate the environmental assessment process, including developing and filing the project description that we plan to submit to the B.C. Environmental Assessment Office and the Canadian Environmental Assessment Agency (CEAA) in second quarter 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. We expect to begin an NGTL open season to provide delivery service to Vanderhoof, B.C. on Coastal GasLink in second quarter 2013.

Portland

We are holding a 45-day binding open season from April to May 2013 to determine the demand for new natural gas supply options for the New England and Atlantic Canada markets. The results could support an increase in our capacity from 168 MMcf/d to between 300 MMcf/d and 350 MMcf/d. The project will require upstream expansion on the Canadian Mainline that will be subject to an assessment of the implications of the recent NEB decision on the Canadian Restructuring Proposal.

Tamazunchale

A variety of construction activities are underway on the Tamazunchale Extension and the project remains on schedule to meet the planned in-service date of first quarter 2014.

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 70 per cent complete and we estimate the total 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 begin in mid 2013 and be complete by mid 2014 at a total cost of approximately US$300 million.

The Gulf Coast Project will have an initial 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. Department of State (DOS) released its Draft Supplemental Environmental Impact Statement for the Keystone XL Pipeline. The impact statement reaffirmed that construction of the proposed pipeline from the U.S./Canada border in Montana to Steele City, Nebraska would not result in any significant impact to the environment. The DOS is in the process of reviewing 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 during a National Interest Determination period of up to 90 days, before making a decision on our Presidential Permit application.

Due to ongoing delays in the issuance of a Presidential Permit for Keystone XL, we now expect the pipeline to be in service in the second half of 2015 and, based on our pipeline construction experience, the US$5.3 billion cost estimate will increase depending on the timing of the permit. As of March 31, 2013, we had invested $1.8 billion in the project.

Energy East Pipeline

We announced in April 2013 that we are holding an open season to obtain firm commitments for a pipeline to transport crude oil from western receipt points to eastern Canadian markets. The open season, which follows a successful expression of interest phase and discussions with prospective shippers, began in April 2013 and closes in June 2013.

The Energy East Pipeline project involves converting natural gas pipeline capacity in approximately 3,000 kilometres of our existing Canadian Mainline to crude oil service and constructing up to approximately 1,400 kilometres of new pipeline. Subject to the results of the open season, the project will have the capacity to transport as much as 850,000 barrels of crude oil per day, increasing access to eastern Canadian markets.

We have begun Aboriginal and stakeholder engagement and field work as part of our initial design and planning. If the open season is successful, we will apply for regulatory approval to build and operate the facilities, with a potential in-service date of late 2017.

Northern Courier Pipeline

The Fort Hills Energy Limited Partnership has not indicated that their recent decision to cancel the Voyageur upgrader project has changed their current plans for Northern Courier. We have nearly completed the field work and Aboriginal and stakeholder engagement necessary to allow us to file the permit application with the Energy Resources Conservation Board and expect to file the application in second quarter 2013.

ENERGY

Ontario Solar

In late 2011, we agreed to buy nine Ontario solar projects (combined capacity of 86 MW) from Canadian Solar Solutions Inc. We expect to close the acquisition of the first three projects (combined capacity of 29 MW) by mid 2013 for a total cost of approximately $175 million. We expect to acquire the remaining six projects later in 2013 and 2014, subject to regulatory approvals.

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.

Other income statement items

three months ended March 31 (unaudited - millions of $)	2013	2012
Comparable interest expense	**257**	242
Comparable interest income and other	**(18)**	(25)
Comparable income taxes	**159**	140
Net income attributable to non-controlling interests	**31**	35

three months ended March 31 (unaudited - millions of $)	2013	2012
Comparable interest on long-term debt		
(including interest on junior subordinated notes)		
Canadian dollar-denominated	**122**	128
U.S. dollar-denominated	**188**	186
Foreign exchange	**1**	-
	311	314
Other interest and amortization expense	**1**	2
Capitalized interest	**(55)**	(74)
Comparable interest expense	**257**	242

Comparable interest expense this quarter was $15 million higher than first quarter 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 this quarter was $7 million lower than first quarter 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 $159 million this quarter compared to $140 million in first quarter 2012. The increase was mainly the result of higher pre-tax earnings in 2013 compared to 2012 and 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 capital markets, cash on hand and substantial committed credit facilities.

CASH FROM OPERATING ACTIVITIES

three months ended March 31 (unaudited - millions of $)	**2013**	**2012**
Funds generated from operations[1]	**916**	871
Increase in operating working capital	**(210)**	(169)
Net cash from operations	**706**	702

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

Net cash provided by operations this quarter was $4 million higher than first quarter 2012, mainly because of an increase in funds generated from our operations which is consistent with our increase in earnings, partly offset by changes in operating working capital.

Our current assets were $2.5 billion and current liabilities were $5.5 billion, leaving us with a working capital deficit of $3.0 billion at March 31, 2013 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 any funding of working capital is managed through our ability to generate cash flow and our ongoing access to capital markets.

CASH USED IN INVESTING ACTIVITIES

three months ended March 31 (unaudited - millions of $)	**2013**	**2012**
Capital expenditures	**929**	464
Equity investments	**32**	216

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

CASH PROVIDED BY/(USED IN) FINANCING ACTIVITIES

three months ended March 31 (unaudited - millions of $)	**2013**	**2012**
Long-term debt issued, net of issue costs	**734**	492
Long-term debt repaid	**(14)**	(548)
Notes payable repaid	**(829)**	(46)
Dividends and distributions paid	**(350)**	(343)
Equity financing activities	**618**	14

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 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.

The net proceeds of the two offerings will be used to fund our capital program, for general corporate purposes and to reduce short term indebtedness.

DIVIDENDS

On April 25, 2013 we declared quarterly dividends as follows:

Quarterly dividend on our common shares
$0.46 per share (for the quarter ending June 30, 2013)
Payable on July 31, 2013 to shareholders of record at the close of business on June 28, 2013

Quarterly dividends on our preferred shares
Series 1 $0.2875 (for the quarter ending June 30, 2013)
Series 3 $0.25 (for the quarter ending June 30, 2013)
Payable on July 2, 2013 to shareholders of record at the close of business on May 31, 2013
Series 5 $0.275 (for the three month period ending July 30, 2013)
Series 7 $0.25 (for the three month period ending July 30, 2013)
Payable on July 30, 2013 to shareholders of record at the close of business on June 28, 2013

SHARE INFORMATION

as at April 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	5 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 March 31, 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	$360 million	TCPL, TCPL USA	Demand lines for issuing letters of credit and as a source of additional liquidity. At March 31, 2013, we had outstanding $640 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

Other than a decrease of $560 million to our capital commitments and $190 million to other purchase commitments, there were no material changes to our contractual obligations in first 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 by continuously forecasting our cash flow for a 12 month period and making sure we have adequate cash balances, cash flow from operations, committed and demand credit facilities and access to capital markets to meet our operating, financing and capital expenditure obligations under both normal and stressed economic conditions.

COUNTERPARTY CREDIT RISK

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

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

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At March 31, 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 $256 million with one counterparty at March 31, 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

First quarter 2013	1.01
First quarter 2012	1.00

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

SIGNIFICANT U.S. DOLLAR-DENOMINATED AMOUNTS

three months ended March 31 (unaudited - millions of US$)	**2013**	**2012**
U.S. and International Natural Gas Pipelines comparable EBIT	**200**	215
U.S. Oil Pipelines comparable EBIT	**94**	89
U.S. Power comparable EBIT	**39**	6
Interest expense on U.S. dollar-denominated long-term debt	**(188)**	(186)
Capitalized interest on U.S. capital expenditures	**44**	26
U.S. non-controlling interests and other	**(48)**	(51)
	141	99

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 $)	**March 31, 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]	**5**	**US 3,800**	82	US 3,800
U.S. dollar forward foreign exchange contracts (maturing 2013)	**(1)**	**US 850**	-	US 250
	4	**US 4,650**	82	US 4,050

1 Fair values equal carrying values.
2 Net income in first quarter 2013 included net realized gains of $7 million (2012 - gains of $7 million) related to the interest component of cross-currency swap settlements.

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

(unaudited - billions of $)	**March 31, 2013**	**December 31, 2012**
Carrying value	**12.1 (US 11.9)**	11.1 (US 11.2)
Fair value	**15.0 (US 14.7)**	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 $)	**March 31, 2013**	**December 31, 2012**
Other current assets	**47**	71
Intangible and other assets	**22**	47
Accounts payable and other	**10**	6
Other long-term liabilities	**55**	30

NON-DERIVATIVE FINANCIAL INSTRUMENTS SUMMARY

	March 31, 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	**443**	**443**	551	551
Accounts receivable and other[3]	**1,269**	**1,322**	1,288	1,337
Available for sale assets[3]	**49**	**49**	44	44
	1,761	**1,814**	1,883	1,932
Financial liabilities[4]				
Notes payable	**1,474**	**1,474**	2,275	2,275
Accounts payable and other long-term liabilities[5]	**1,034**	**1,034**	1,535	1,535
Accrued interest	**352**	**352**	368	368
Long-term debt	**19,926**	**25,081**	18,913	24,573
Junior subordinated notes	**1,015**	**1,083**	994	1,054
	23,801	**29,024**	24,085	29,805

1 Recorded at amortized cost, except for US$350 million (December 31, 2012 - US$350 million) of long-term debt that is attributed to hedged risk which is 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 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 March 31, 2013, financial assets of $1.0 billion (December 31, 2012 - $1.1 billion) are included in accounts receivable, $70 million (December 31, 2012 - $40 million) in other current assets and $217 million (December 31, 2012 - $240 million) in intangible and other assets.

4 Condensed consolidated statement of income in first quarter 2013 included losses of $10 million (2012 - losses of $15 million) for fair value adjustments related to interest rate swap agreements on US$350 million of long-term debt at March 31, 2013 (December 31, 2012 - US$350 million). There were no other unrealized gains or losses from fair value adjustments to non-derivative financial instruments.

5 At March 31, 2013, financial liabilities of $1.0 billion (December 31, 2012 - $1.5 billion) are included in accounts payable, and $41 million (December 31, 2012 - $38 million) in other long-term liabilities.

DERIVATIVE INSTRUMENTS SUMMARY

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

2013 (unaudited - millions of $ unless noted otherwise)	Power	Natural gas	Foreign exchange	Interest
Derivative instruments held for trading[1]				
Fair values[2]				
Assets	**$159**	**$85**	**$-**	**$13**
Liabilities	**$(206)**	**$(93)**	**$(8)**	**$(13)**
Notional values				
Volumes[3]				
Sales	**36,445**	**71**	**-**	**-**
Purchases	**34,536**	**102**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**620**
U.S. dollars	**-**	**-**	**US 1,396**	**US 200**
Net unrealized (losses)/gains in the three months ended March 31, 2013[4]	**$(8)**	**$9**	**$(6)**	**$-**
Net realized losses in the three months ended March 31, 2013[4]	**$(7)**	**$(2)**	**$(1)**	**$-**
Maturity dates	**2013-2017**	**2013-2016**	**2013-2014**	**2013-2016**
Derivative instruments in hedging relationships[5,6]				
Fair values[2]				
Assets	**$70**	**$-**	**$-**	**$10**
Liabilities	**$(73)**	**$(1)**	**$(36)**	**$-**
Notional values				
Volumes[3]				
Sales	**6,358**	**-**	**-**	**-**
Purchases	**14,400**	**1**	**-**	**-**
U.S. dollars	**-**	**-**	**US 23**	**US 350**
Cross-currency	**-**	**-**	**136/US 100**	**-**
Net realized gains in the three months ended March 31, 2013[4]	**$73**	**$-**	**$-**	**$2**
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. 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 $10 million and a notional amount of US$350 million. For the three months ended March 31, 2013, net realized gains on fair value hedges were $2 million and were included in interest expense. For the three months ended March 31, 2013, we did not record any amounts in net income related to ineffectiveness for fair value hedges.

6 For the three months ended March 31, 2013, there were no gains or losses included in net income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

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

2012 (unaudited - millions of $ unless noted otherwise)	Power	Natural gas	Foreign exchange	Interest
Derivative instruments held for trading[1]				
Fair values[2,3]				
Assets	$139	$88	$1	$14
Liabilities	$(176)	$(104)	$(2)	$(14)
Notional values[3]				
Volumes[4]				
Sales	31,066	65	-	-
Purchases	31,135	83	-	-
Canadian dollars	-	-	-	620
U.S. dollars	-	-	US 1,408	US 200
Net unrealized (losses)/gains in the three months ended March 31, 2012[5]	$(7)	$(14)	$6	$-
Net realized (losses)/gains in the three months ended March 31, 2012[5]	$15	$(10)	$9	$-
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 three months ended March 31, 2012[5]	$(32)	$(6)	$-	$1
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. For the three months ended March 31, 2012, net realized gains on fair value hedges were $2 million and were included in interest expense. For the three months ended March 31, 2012, we did not record any amounts in net income related to ineffectiveness for fair value hedges.
7 For the three months ended March 31, 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 $)	March 31, 2013	December 31, 2012
Current		
Other current assets	**248**	259
Accounts payable and other	**(302)**	(283)
Long term		
Intangible and other assets	**158**	187
Other long-term liabilities	**(193)**	(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 March 31**	**Power**		**Natural gas**		**Foreign exchange**		**Interest**	
(unaudited – millions of $, pre-tax)	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Change in fair value of derivative instruments recognized in OCI (effective portion)	**36**	(66)	**-**	(10)	**2**	(3)	**-**	-
Reclassification of gains and losses on derivative instruments from AOCI to net income (effective portion)	**(11)**	47	**-**	13	**-**	-	**4**	6
Gains and losses on derivative instruments recognized in earnings (ineffective portion)	**(5)**	(6)	**-**	(2)	**-**	-	**-**	-

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 March 31, 2013, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $34 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 March 31, 2013, we would have been required to provide collateral of $34 million (December 31, 2012 - $37 million) to our counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

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

FAIR VALUE HIERARCHY

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

Levels	How fair value has been determined
Level I	Quoted prices in active markets for identical assets and liabilities that we have the ability to access at the measurement date.
Level II	Valuation based on the extrapolation of inputs, other than quoted prices included within Level I, for which all significant inputs are observable directly or indirectly. Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers. This category includes interest rate and foreign exchange derivative assets and liabilities where fair value is determined using the income approach and power and natural gas commodity derivatives where fair value is determined using the market approach.
Level III	Valuation of assets and liabilities measured on a recurring basis using a market approach based on inputs that are unobservable and significant to the overall fair value measurement. This category includes long-dated commodity transactions in certain markets where liquidity is low. Long term electricity prices are estimated using a third-party modeling tool which takes into account physical operating characteristics of generation facilities in the markets in which we operate. Model inputs include market fundamentals such as fuel prices, power supply additions and retirements, power demand, seasonal hydro conditions and transmission constraints. Long-term North American natural gas prices are based on a view of future natural gas supply and demand, as well as exploration and development costs. Significant decreases in fuel prices or demand for electricity or natural gas, or increases in the supply of electricity or natural gas is expected to or may result in a lower fair value measurement of contracts included in Level III.

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

	Quoted prices in active markets (Level I)[1]		**Significant other observable inputs (Level II)**		**Significant unobservable inputs (Level III)**		**Total**	
(unaudited – millions of $, pre-tax)	**Mar 31, 2013**	**Dec 31, 2012**	**Mar 31, 2013**	**Dec 31, 2012**	**Mar 31, 2013**	**Dec 31, 2012**	**Mar 31, 2013**	**Dec 31, 2012**
Derivative instrument assets:								
Power commodity contracts	**-**	-	**224**	213	**5**	2	**229**	215
Natural gas commodity contracts	**77**	75	**8**	13	**-**	-	**85**	88
Foreign exchange contracts	**-**	-	**69**	119	**-**	-	**69**	119
Interest rate contracts	**-**	-	**23**	24	**-**	-	**23**	24
Derivative instrument liabilities:								
Power commodity contracts	**-**	-	**(275)**	(269)	**(4)**	(4)	**(279)**	(273)
Natural gas commodity contracts	**(79)**	(95)	**(15)**	(11)	**-**	-	**(94)**	(106)
Foreign exchange contracts	**-**	-	**(109)**	(76)	**-**	-	**(109)**	(76)
Interest rate contracts	**-**	-	**(13)**	(14)	**-**	-	**(13)**	(14)
Non-derivative financial instruments:								
Available for sale assets	**49**	44	**-**	-	**-**	-	**49**	44
	47	24	**(88)**	(1)	**1**	(2)	**(40)**	21

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

three months ended March 31 (unaudited - millions of $, pre-tax)	**Derivatives[1]**	
	2013	**2012**
Balance at January 1	**(2)**	(15)
Total gains included in OCI	**3**	4
Balance at March 31	**1**	(11)

[1] For the three months ended March 31, 2013, the unrealized gains or losses included in net income attributed to derivatives in the Level III category that were still held at the reporting date was nil (2012 - nil).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $3 million decrease or increase, respectively, in the fair value of outstanding derivative instruments included in Level III at March 31, 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 March 31, 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 first 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 in subsequent quarters of 2013. The phased implementation period is planned to begin July 1, 2013.

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. 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

Effective January 1, 2013, we adopted the Accounting Standards Update (ASU) on disclosures about balance sheet offsetting as issued by the Financial Accounting Standards Board (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 accumulated other comprehensive income (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

(millions of $, except per share amounts)

	2013	2012				2011		
(unaudited)	First	Fourth	Third	Second	First	Fourth	Third	Second
Revenues	**2,252**	2,089	2,126	1,847	1,945	2,015	2,043	1,851
Net income attributable to common shares	**446**	306	369	272	352	376	386	353
Share Statistics								
Net Income per common share - basic and diluted	**$0.63**	$0.43	$0.52	$0.39	$0.50	$0.53	$0.55	$0.50
Dividend declared per common share	**$0.46**	$0.44	$0.44	$0.44	$0.44	$0.42	$0.42	$0.42

FACTORS AFFECTING QUARTERLY FINANCIAL INFORMATION BY BUSINESS SEGMENT

Quarter-over-quarter revenues and net incomes sometimes fluctuate. The causes of this fluctuation 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

First quarter 2013

- EBIT included $42 million of pre-tax income ($84 million after-tax) from the Canadian Restructuring Proposal 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 $50 million pre-tax charge ($37 million after-tax) 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.

Second quarter 2011

- EBIT included net unrealized losses of $3 million pre-tax ($2 million after-tax) from certain risk management activities.

Condensed consolidated statement of income

three months ended March 31 (unaudited - millions of Canadian $ except per share amounts)	2013	2012
Revenues		
Natural gas pipelines	**1,157**	1,085
Oil pipelines	**271**	259
Energy	**824**	601
	2,252	1,945
Income from Equity Investments	**93**	60
Operating and Other Expenses		
Plant operating costs and other	**641**	592
Commodity purchases resold	**376**	213
Property taxes	**109**	115
Depreciation and amortization	**367**	344
	1,493	1,264
Financial Charges/(Income)		
Interest expense	**258**	242
Interest income and other	**(13)**	(31)
	245	211
Income before Income Taxes	**607**	530
Income Taxes Expense		
Current	**79**	56
Deferred	**36**	73
	115	129
Net Income	**492**	401
Net income attributable to non-controlling interests	**31**	35
Net Income Attributable to Controlling Interests	**461**	366
Preferred share dividends	**15**	14
Net Income Attributable to Common Shares	**446**	352
Net Income per Common Share		
Basic and diluted	**$0.63**	$0.50
Dividends Declared per Common Share	**$0.46**	$0.44
Weighted Average Number of Common Shares (millions)		
Basic	**706**	704
Diluted	**707**	705

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

three months ended March 31 (unaudited - millions of Canadian $)	**2013**	**2012**
Net Income	**492**	401
Other Comprehensive Income/(Loss), Net of Income Taxes		
Foreign currency translation gains and losses on investments in foreign operations	**111**	(107)
Change in fair value of net investment hedges	**(49)**	38
Change in fair value of cash flow hedges	**21**	(45)
Reclassification to net income of gains and losses on cash flow hedges	**(4)**	45
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**6**	10
Other comprehensive income on equity investments	**(1)**	5
Other comprehensive income/(loss) (Note 7)	**84**	(54)
Comprehensive Income	**576**	347
Comprehensive income attributable to non-controlling interests	**51**	18
Comprehensive Income Attributable to Controlling Interests	**525**	329
Preferred share dividends	**15**	14
Comprehensive Income Attributable to Common Shares	**510**	315

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of cash flows

three months ended March 31 (unaudited - millions of Canadian $)	**2013**	**2012**
Cash Generated from Operations		
Net income	**492**	401
Depreciation and amortization	**367**	344
Deferred income taxes	**36**	73
Income from equity investments	**(93)**	(60)
Distributed earnings received from equity investments	**84**	83
Employee post-retirement benefits funding lower than expense	**15**	7
Other	**15**	23
Increase of operating working capital	**(210)**	(169)
Net cash provided by operations	**706**	702
Investing Activities		
Capital expenditures	**(929)**	(464)
Equity investments	**(32)**	(216)
Deferred amounts and other	**(20)**	(37)
Net cash used in investing activities	**(981)**	(717)
Financing Activities		
Dividends on common and preferred shares	**(315)**	(310)
Distributions paid to non-controlling interests	**(35)**	(33)
Notes payable repaid, net	**(829)**	(46)
Long-term debt issued, net of issue costs	**734**	492
Repayment of long-term debt	**(14)**	(548)
Common shares issued, net of issue costs	**32**	14
Preferred shares issued, net of issue costs	**586**	-
Net cash provided by/(used in) financing activities	**159**	(431)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**8**	(12)
Decrease in Cash and Cash Equivalents	**(108)**	(458)
Cash and Cash Equivalents		
Beginning of period	**551**	654
Cash and Cash Equivalents		
End of period	**443**	196

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)	March 31 2013	December 31 2012
ASSETS		
Current Assets		
Cash and cash equivalents	**443**	551
Accounts receivable	**1,031**	1,052
Inventories	**231**	224
Other	**746**	997
	2,451	2,824
Plant, Property and Equipment, net of accumulated depreciation of $16,908 and $16,540, respectively	**34,356**	33,713
Equity Investments	**5,396**	5,366
Goodwill	**3,530**	3,458
Regulatory Assets	**1,915**	1,629
Intangible and Other Assets	**1,386**	1,343
	49,034	48,333
LIABILITIES		
Current Liabilities		
Notes payable	**1,474**	2,275
Accounts payable and other	**1,971**	2,344
Accrued interest	**352**	368
Current portion of long-term debt	**1,660**	894
	5,457	5,881
Regulatory Liabilities	**275**	268
Other Long-Term Liabilities	**859**	882
Deferred Income Tax Liabilities	**4,001**	3,953
Long-Term Debt	**18,266**	18,019
Junior Subordinated Notes	**1,015**	994
	29,873	29,997
EQUITY		
Common shares, no par value	**12,106**	12,069
Issued and outstanding: March 31, 2013 - 706 million shares		
December 31, 2012 - 705 million shares		
Preferred shares	**1,810**	1,224
Additional paid-in capital	**376**	379
Retained earnings	**4,809**	4,687
Accumulated other comprehensive loss (Note 7)	**(1,384)**	(1,448)
Controlling Interests	**17,717**	16,911
Non-controlling interests	**1,444**	1,425
	19,161	18,336
	49,034	48,333

Contingencies and Guarantees (Note 10)

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of equity

(unaudited - millions of Canadian $)	Three months ended March 31 2013	2012
Common Shares		
Balance at beginning of period	**12,069**	12,011
Shares issued on exercise of stock options	**37**	15
Balance at end of period	**12,106**	12,026
Preferred Shares		
Balance at beginning of period	**1,224**	1,224
Share issuance, net of issue costs	**586**	-
Balance at end of period	**1,810**	1,224
Additional Paid-In Capital		
Balance at beginning of period	**379**	380
Issuance of stock options, net of exercises	**(3)**	(1)
Balance at end of period	**376**	379
Retained Earnings		
Balance at beginning of period	**4,687**	4,628
Net income attributable to controlling interests	**461**	366
Common share dividends	**(324)**	(310)
Preferred share dividends	**(15)**	(14)
Balance at end of period	**4,809**	4,670
Accumulated Other Comprehensive Loss		
Balance at beginning of period	**(1,448)**	(1,449)
Other comprehensive income/(loss)	**64**	(37)
Balance at end of period	**(1,384)**	(1,486)
Equity Attributable to Controlling Interests	**17,717**	16,813
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	**19**	26
Preferred share dividends of TCPL	**6**	6
Portland	**6**	3
Other comprehensive income/(loss) attributable to non-controlling interests	**20**	(17)
Distributions to non-controlling interests	**(35)**	(33)
Other	**3**	(3)
Balance at end of period	**1,444**	1,447
Total Equity	**19,161**	18,260

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 United States generally accepted accounting principles (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 Pipeline 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 Accounting Standards Update (ASU) on disclosures about balance sheet offsetting as issued by the Financial Accounting Standards Board (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 accumulated other comprehensive income (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 March 31	**Natural gas pipelines**		**Oil pipelines**		**Energy**		**Corporate**		**Total**	
(unaudited - millions of Canadian $)	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Revenues	**1,157**	1,085	**271**	259	**824**	601	**-**	-	**2,252**	1,945
Income from equity investments	**40**	46	**-**	-	**53**	14	**-**	-	**93**	60
Plant operating costs and other	**(318)**	(327)	**(79)**	(69)	**(210)**	(167)	**(34)**	(29)	**(641)**	(592)
Commodity purchases resold	**-**	-	**-**	-	**(376)**	(213)	**-**	-	**(376)**	(213)
Property taxes	**(78)**	(79)	**(13)**	(17)	**(18)**	(19)	**-**		**(109)**	(115)
Depreciation and amortization	**(253)**	(232)	**(37)**	(36)	**(74)**	(73)	**(3)**	(3)	**(367)**	(344)
	548	493	**142**	137	**199**	143	**(37)**	(32)	**852**	741
Interest expense									**(258)**	(242)
Interest income and other									**13**	31
Income before Income Taxes									**607**	530
Income taxes expense									**(115)**	(129)
Net Income									**492**	401
Net Income Attributable to Non-Controlling Interests									**(31)**	(35)
Net Income Attributable to Controlling Interests									**461**	366
Preferred Share Dividends									**(15)**	(14)
Net Income Attributable to Common Shares									**446**	352

TOTAL ASSETS

(unaudited - millions of Canadian $)	**March 31, 2013**	**December 31, 2012**
Natural Gas Pipelines	**23,785**	23,210
Oil Pipelines	**10,786**	10,485
Energy	**13,173**	13,157
Corporate	**1,290**	1,481
	49,034	48,333

4. Income Taxes

At March 31, 2013, the total unrecognized tax benefit of uncertain tax positions is approximately $50 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 months ended March 31, 2013 is $1 million of interest expense and nil for penalties (March 31, 2012 - $1 million for interest expense and nil for penalties). At March 31, 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 three-month periods ended March 31, 2013 and 2012 were 19 per cent and 24 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.

TransCanada expects the enactment of certain Canadian Federal tax legislation in the next twelve months which is expected to result in a favourable income tax adjustment of approximately $25 million. Otherwise, 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 months ended March 31, 2013, the Company capitalized interest related to capital projects of $55 million (March 31, 2012 - $74 million).

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

6. Share 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 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 for the initial period ending April 30, 2019, with the first dividend payment scheduled for April 30, 2013. 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 net proceeds of this offering are expected to be used to partially fund capital projects, for general corporate purposes and to repay short-term debt.

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/(Loss) And Accumulated Other Comprehensive Loss

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

three months ended March 31, 2013 (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	**77**	**34**	**111**
Change in fair value of net investment hedges	**(66)**	**17**	**(49)**
Change in fair value of cash flow hedges	**38**	**(17)**	**21**
Reclassification to net income of gains and losses on cash flow hedges	**(7)**	**3**	**(4)**
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**10**	**(4)**	**6**
Other comprehensive income on equity investments	**(1)**	**-**	**(1)**
Other comprehensive income	**51**	**33**	**84**

three months ended March 31, 2012 (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	(85)	(22)	(107)
Change in fair value of net investment hedges	49	(11)	38
Change in fair value of cash flow hedges	(79)	34	(45)
Reclassification to net income of gains and losses on cash flow hedges	66	(21)	45
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	6	4	10
Other comprehensive income on equity investments	6	(1)	5
Other comprehensive loss	(37)	(17)	(54)

The changes in accumulated other comprehensive loss by component, for the three months ended March 31, 2013, are as follows:

(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]	**42**	**19**	**1**	**62**
Amounts reclassified from accumulated other comprehensive loss[3]	**-**	**(4)**	**6**	**2**
Net current period other comprehensive income	**42**	**15**	**7**	**64**
AOCI Balance at March 31, 2013	**(665)**	**(95)**	**(624)**	**(1,384)**

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 $20 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 $24 million ($16 million, net of tax). 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, for the three months ended March 31, 2013, are as follows:

Details about accumulated other comprehensive loss components (unaudited - millions of Canadian $)	**Amounts reclassified from accumulated other comprehensive loss**[1]	**Affected line item in the condensed consolidated statement of income**
Cash flow hedges		
Power	**11**	Revenue (Energy)
Interest	**(4)**	Interest expense
	7	Total before tax
	(3)	Income tax expense
	4	Net of tax
Pension and other post-retirement plan adjustments		
Amortization of net loss[2]	**(10)**	Total before tax
	4	Income tax expense
	(6)	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 March 31 (millions of Canadian $)	**Pension benefit plans**		**Other post-retirement benefit plans**	
	2013	**2012**	**2013**	**2012**
Service cost	**19**	16	**1**	1
Interest cost	**24**	23	**2**	2
Expected return on plan assets	**(29)**	(28)	**-**	-
Amortization of actuarial loss	**9**	5	**1**	-
Amortization of regulatory asset	**7**	5	**-**	-
Net benefit cost recognized	**30**	21	**4**	3

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 March 31, 2013, there were no significant amounts past due or impaired, and there were no significant credit losses during the year.

At March 31, 2013, the Company had a credit risk concentration of $256 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 $)	March 31, 2013	December 31, 2012
Carrying value	**12.1 (US 11.9)**	11.1 (US 11.2)
Fair value	**15.0 (US 14.7)**	14.3 (US 14.4)

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

(unaudited - millions of $)	March 31, 2013	December 31, 2012
Other current assets	**47**	71
Intangible and other assets	**22**	47
Accounts payable and other	**10**	6
Other long-term liabilities	**55**	30

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

	March 31, 2013		December 31, 2012	
Asset/(liability) (unaudited - millions of Canadian $)	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]	**5**	**US 3,800**	82	US 3,800
U.S. dollar forward foreign exchange contracts (maturing 2013)	**(1)**	**US 850**	-	US 250
	4	**US 4,650**	82	US 4,050

1 Fair values equal carrying values.

2 Net Income in the three months ended March 31, 2013 included net realized gains of $7 million (2012 - gains of $7 million) 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:

	March 31, 2013		December 31, 2012	
(unaudited - millions of Canadian $)	Carrying amount[1]	Fair value[2]	Carrying amount[1]	Fair value[2]
Financial assets				
Cash and cash equivalents	**443**	**443**	551	551
Accounts receivable and other[3]	**1,269**	**1,322**	1,288	1,337
Available for sale assets	**49**	**49**	44	44
	1,761	**1,814**	1,883	1,932
Financial liabilities[4]				
Notes payable	**1,474**	**1,474**	2,275	2,275
Accounts payable and other long-term liabilities[5]	**1,034**	**1,034**	1,535	1,535
Accrued interest	**352**	**352**	368	368
Long-term debt	**19,926**	**25,081**	18,913	24,573
Junior subordinated notes	**1,015**	**1,083**	994	1,054
	23,801	**29,024**	24,085	29,805

1 Recorded at amortized cost, except for US$350 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 March 31, 2013, financial assets of $1.0 billion (December 31, 2012 - $1.1 billion) are included in accounts receivable, $70 million (December 31, 2012 - $40 million) in other current assets and $217 million (December 31, 2012 - $240 million) in intangible and other assets.

4 Condensed consolidated statement of income in the three months ended March 31, 2013 included losses of $10 million (2012 - losses of $15 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$350 million of long-term debt at March 31, 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 March 31, 2013, financial liabilities of $1.0 billion (December 31, 2012 - $1.5 billion) are included in accounts payable and $41 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	**$159**	**$85**	**$-**	**$13**
Liabilities	**$(206)**	**$(93)**	**$(8)**	**$(13)**
Notional values				
Volumes[3]				
Sales	**36,445**	**71**	**-**	**-**
Purchases	**34,536**	**102**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**620**
U.S. dollars	**-**	**-**	**US 1,396**	**US 200**
Net unrealized (losses)/gains in the three months ended March 31, 2013[4]	**$(8)**	**$9**	**$(6)**	**$-**
Net realized losses in the three months ended March 31, 2013[4]	**$(7)**	**$(2)**	**$(1)**	**$-**
Maturity dates	**2013-2017**	**2013-2016**	**2013-2014**	**2013-2016**
Derivative instruments in hedging relationships[5,6]				
Fair values[2]				
Assets	**$70**	**$-**	**$-**	**$10**
Liabilities	**$(73)**	**$(1)**	**$(36)**	**$-**
Notional values				
Volumes[3]				
Sales	**6,358**	**-**	**-**	**-**
Purchases	**14,400**	**1**	**-**	**-**
U.S. dollars	**-**	**-**	**US 23**	**US 350**
Cross-currency	**-**	**-**	**136/US 100**	**-**
Net realized gains in the three months ended March 31, 2013[4]	**$73**	**$-**	**$-**	**$2**
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 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 instruments designated as fair value hedges with a fair value of $10 million and a notional amount of US$350 million. For the three months ended March 31, 2013, net realized gains on fair value hedges were $2 million and were included in interest expense. For the three months ended March 31, 2013, the Company did not record any amounts in net income related to ineffectiveness for fair value hedges.

6 For the three months ended March 31, 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 three months ended March 31, 2012[5]	$(7)	$(14)	$6	$-
Net realized (losses)/gains in the three months ended March 31, 2012[5]	$15	$(10)	$9	$-
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 three months ended March 31, 2012[5]	$(32)	$(6)	$-	$1
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 instruments designated as fair value hedges with a fair value of $10 million and a notional amount of US$350 million. For the three months ended March 31, 2012, net realized gains on fair value hedges were $2 million and were included in interest expense. For the three months ended March 31, 2012, the Company did not record any amounts in net income related to ineffectiveness for fair value hedges.

7 For the three months ended March 31, 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 $)	March 31, 2013	December 31, 2012
Current		
Other current assets	**248**	259
Accounts payable and other	**(302)**	(283)
Long term		
Intangible and other assets	**158**	187
Other long-term liabilities	**(193)**	(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 March 31	**Power**		**Natural gas**		**Foreign exchange**		**Interest**	
(unaudited - millions of Canadian $, pre-tax)	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Changes in fair value of derivative instruments recognized in OCI (effective portion)	**36**	(66)	**-**	(10)	**2**	(3)	**-**	-
Reclassification of gains and losses on derivative instruments from AOCI to net income (effective portion)	**(11)**	47	**-**	13	**-**	-	**4**	6
Gains and losses on derivative instruments recognized in earnings (ineffective portion)	**(5)**	(6)	**-**	(2)	**-**	-	**-**	-

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 March 31, 2013 (unaudited - millions of Canadian $)	**Gross derivative instruments presented in the balance sheet**	**Amounts available for offset[1]**	**Net amounts**
Derivative - Asset			
Power	**229**	(140)	**89**
Natural gas	**85**	(74)	**11**
Foreign exchange	**69**	(40)	**29**
Interest	**23**	(4)	**19**
Total	**406**	(258)	**148**
Derivative - Liability			
Power	**(279)**	140	**(139)**
Natural gas	**(94)**	74	**(20)**
Foreign exchange	**(109)**	40	**(69)**
Interest	**(13)**	4	**(9)**
Total	**(495)**	258	**(237)**

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

With respect to all financial arrangements, including the derivative instruments presented above, as at March 31, 2013, the Company had provided cash collateral of $166 million and letters of credit of $45 million to its counterparties. The Company held $1 million in cash collateral and $6 million in letters of credit on asset exposures at March 31, 2013.

The following table shows the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis as at December 31, 2012:

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

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

With respect to all financial arrangements, including the derivative instruments presented above as at December 31, 2012, the Company had provided cash collateral of $189 million and letters of credit of $45 million to its counterparties. The Company held $2 million in cash collateral and $5 million in letters of credit on asset exposures at December 31, 2012.

CREDIT RISK RELATED CONTINGENT FEATURES

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

Based on contracts in place and market prices at March 31, 2013, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $34 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 March 31, 2013, the Company would have been required to provide collateral of $34 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.

In Level I, the fair value of assets and liabilities is determined by reference to quoted prices in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date.

In Level II, the fair value of interest rate and foreign exchange derivative assets and liabilities is determined using the income approach. The fair value of power and gas commodity assets and liabilities is determined using the market approach. Under both approaches, the valuation is based on the extrapolation of inputs, other than quoted prices included within Level I, for which all significant inputs are observable directly or indirectly. Such inputs include published exchange rates, interest rates, interest rate swap curves, yield curves, and broker quotes from external data service providers. Transfers between Level I and Level II would occur when there is a change in market circumstances. There were no transfers between Level I and Level II in first quarter 2013 and 2012.

In Level III, the fair value of assets and liabilities measured on a recurring basis is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement. 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. There were no transfers between Level II and Level III in first quarter 2013 and 2012.

Long-dated commodity transactions in certain markets where liquidity is low are included in Level III of the fair value hierarchy, as the related commodity prices are not readily observable. 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 the Company operates. Model inputs include market fundamentals such as fuel prices, power supply additions and retirements, power demand, seasonal hydro conditions and transmission constraints. Long-term North American natural gas prices are based on a view of future natural gas supply and demand, as well as exploration and development costs. Long-term prices are reviewed by management and the Board on a periodic basis. 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 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)		**Significant other observable inputs (Level II)**		**Significant unobservable inputs (Level III)**		**Total**	
(unaudited - millions of Canadian $, pre-tax)	**Mar 31 2013**	**Dec 31 2012**	**Mar 31 2013**	**Dec 31 2012**	**Mar 31 2013**	**Dec 31 2012**	**Mar 31 2013**	**Dec 31 2012**
Derivative instrument assets:								
Power commodity contracts	**-**	-	**224**	213	**5**	2	**229**	215
Natural gas commodity contracts	**77**	75	**8**	13	**-**	-	**85**	88
Foreign exchange contracts	**-**	-	**69**	119	**-**	-	**69**	119
Interest rate contracts	**-**	-	**23**	24	**-**	-	**23**	24
Derivative Instrument Liabilities:								
Power commodity contracts	**-**	-	**(275)**	(269)	**(4)**	(4)	**(279)**	(273)
Natural gas commodity contracts	**(79)**	(95)	**(15)**	(11)	**-**	-	**(94)**	(106)
Foreign exchange contracts	**-**	-	**(109)**	(76)	**-**	-	**(109)**	(76)
Interest rate contracts	**-**	-	**(13)**	(14)	**-**	-	**(13)**	(14)
Non-derivative financial instruments:								
Available for sale assets	**49**	44	**-**	-	**-**	-	**49**	44
	47	24	**(88)**	(1)	**1**	(2)	**(40)**	21

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

three months ended March 31	**Derivatives**[1]	
(unaudited - millions of Canadian $, pre-tax)	**2013**	**2012**
Balance at January 1	**(2)**	(15)
Total gains included in OCI	**3**	4
Balance at March 31	**1**	(11)

1 For the three months ended March 31, 2013 the unrealized gains or losses included in net income attributed to derivatives in the level III category that were still held at the reporting date was nil (2012 - nil).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $3 million decrease or increase, respectively, in the fair value of outstanding derivative instruments included in Level III as at March 31, 2013.

10. 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 recorded in revenues in first quarter 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. The Bruce B guarantees have terms ranging to 2018 except for one guarantee with no termination date that has no exposure associated with it. In addition, TransCanada and BPC have each severally guaranteed one-half of certain contingent financial obligations of Bruce A related to a sublease agreement, an agreement with the OPA to restart the Bruce A power generation units, and certain other financial obligations. The Bruce A guarantees have terms to 2019. TransCanada's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated to be $887 million at March 31, 2013. The carrying value of these Bruce Power guarantees at March 31, 2013 was $10 million which is included in other long-term liabilities. 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. The guarantees have terms ranging from 2013 to 2040. TransCanada's share of the potential exposure under these assurances was estimated to be $42 million at March 31, 2013. The carrying value of these guarantees at March 31, 2013 was $9 million, which has been included in other long-term 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.