



TRANSCANADA CORPORATION – SECOND QUARTER 2010

# **Quarterly Report to Shareholders**

## **TransCanada Reports Second Quarter Results, \$22 Billion Capital Program Drives Future Growth**

CALGARY, Alberta – **July 29, 2010** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced net income applicable to common shares for second quarter 2010 of \$285 million or \$0.41 per share. Comparable earnings were \$275 million or \$0.40 per share. Net income applicable to common shares and comparable earnings were both reduced by \$28 million (\$0.04 per share) due to losses on derivatives used to manage the Company's economic exposure to rising interest rates and foreign exchange rate fluctuations on U.S. dollar denominated income and foreign exchange losses on conversion of U.S. dollar working capital balances due to the strengthening U.S. dollar. In addition, approximately \$20 million (\$0.03 per share) of net income related to the Alberta System was not recognized in the first six months of 2010 pending final approval by the National Energy Board (NEB) of a three year settlement with customers.

“TransCanada's core businesses – pipe and energy – performed well this past quarter,” says Russ Girling, TransCanada's president and chief executive officer. “We continue to make great strides in advancing our \$22 billion capital growth program. TransCanada took a major step forward last month as the first phase of the Keystone Pipeline System began commercial operations, delivering crude oil to refineries in Wood River and Patoka, Illinois. We expect to generate approximately \$1 billion of additional EBITDA next year as projects such as Keystone; the Halton Hills and Coolidge Generating Stations; and our Guadalajara and Bison Pipelines become operational.”

### **Second Quarter Highlights**

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

- Began commercial deliveries of crude oil to U.S. Midwest markets with the placing into service of the first phase of the US\$12 billion Keystone Pipeline
- Reached a three year settlement with shippers on the Alberta and Foothills Systems that sets the equity return at 9.7 per cent on deemed common equity of 40 per cent
- Net income applicable to common shares of \$285 million or \$0.41 per share
- Comparable earnings of \$275 million or \$0.40 per share
- Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of \$928 million
- Funds generated from operations of \$935 million
- Invested \$1 billion to advance unprecedented \$22 billion capital program
- Common share dividend of \$0.40 per share for the quarter ending September 30, 2010

Net income applicable to common shares for second quarter 2010 was \$285 million (\$0.41 per share) compared to \$314 million (\$0.50 per share) in second quarter 2009. The decrease was primarily due to losses in second quarter 2010 compared to gains in second quarter 2009 on derivatives used to manage economic exposures to foreign exchange and interest rate fluctuations that do not qualify as hedges for accounting and the translation of working capital balances, lower volumes and higher costs associated with lower plant availability at Bruce A and lower realized power prices at Bruce B. Partially offsetting these decreases were higher earnings from Western Power resulting from higher realized power prices and lower net interest expense from increased capitalization of interest related to the Company's large capital growth program.

Net income per share in second quarter 2010 decreased \$0.05 as a result of a ten per cent increase in the average number of common shares outstanding following a 58.4 million common share issuance in second quarter 2009.

Notable recent developments in Pipelines, Energy and Corporate include:

**Pipelines:**

- On June 30, 2010, the first phase of the US\$12 billion Keystone Pipeline began commercial deliveries of crude oil to U.S. Midwest markets at Wood River and Patoka, Illinois. This phase is expected to be operating at its initial nominal capacity of 435,000 barrels per day (Bbl/d) in fourth quarter 2010. The Keystone Pipeline project will play an important role in linking a secure and growing supply of Canadian crude oil with the largest refining markets in the United States, significantly improving North American energy security.

Construction of the second phase of Keystone to expand nominal capacity to 591,000 Bbl/d and extend the pipeline to Cushing, Oklahoma began in second quarter 2010. Commercial in-service of the second phase is expected to occur in first quarter 2011, with contract volumes increasing to 530,000 Bbl/d.

TransCanada also continues to advance the 500,000 Bbl/d Gulf Coast expansion, which has secured long-term commitments of 380,000 Bbl/d. Assuming regulatory approval is granted in first quarter 2011, construction is expected to begin shortly thereafter. This expansion will increase nominal capacity to 1.1 million Bbl/d.

Based on firm, binding contracts that total 910,000 Bbl/d for an average term of 18 years, TransCanada expects Keystone to generate EBITDA of approximately US\$1.2 billion in 2013, its first full year of commercial operations to both the U.S. Midwest and Gulf Coast markets. If volumes were to increase to 1.1 million Bbl/d, the full commercial design of the system, Keystone would generate annual EBITDA of approximately US\$1.5 billion. In the future, Keystone could be economically expanded from 1.1 million Bbl/d to 1.5 million Bbl/d to meet market demand.

- In June 2010, TransCanada announced it reached a three year settlement with Alberta System shippers regarding the annual revenue requirement for the years 2010 to 2012. The settlement sets the equity return at 9.7 per cent on deemed common equity of 40 per cent. In addition to cost of capital, the settlement encompasses all other elements of the Alberta System costs of service including operating, maintenance and administration, income taxes, depreciation and various flow-through cost components including interest expense, property taxes and transportation by others. TransCanada expects to receive regulatory approval of the settlement from the National Energy Board in third quarter 2010 at which time the impact of the settlement from its effective date of January 1, 2010 will be recognized.

Foothills Pipe Lines Ltd. also reached an agreement that establishes the equity return at 9.7 per cent on deemed common equity of 40 per cent for the years 2010 to 2012.

- Construction of the Groundbirch pipeline is expected to begin in August 2010 and estimated to be in service by November 2010. When completed, the project will consist of approximately 77 kilometres (km) (48 miles) of 36-inch diameter natural gas pipeline that will extend the Alberta System, connecting to natural gas supplies in the Montney shale gas formation in northeast B.C. The approximate \$200 million project has firm transportation contracts that will reach 1.1 billion cubic feet per day (Bcf/d) by 2014.

TransCanada continues to advance the Horn River project which will bring northeast B.C. shale gas to market through the Alberta System. Subject to regulatory approvals, the approximate \$310 million project is expected to be operational early in second quarter 2012 with commitments for contracted gas rising to approximately 540 million cubic feet per day (mmcf/d) by 2014.

TransCanada continues to receive additional requests for firm transportation service on both the Horn River and Groundbirch pipeline projects.

- In July 2010, TransCanada received regulatory approvals to proceed with construction of a majority of the Bison natural gas pipeline project and construction activities have commenced. Approvals for the remainder of the project are expected in third quarter 2010. Once completed, the pipeline will deliver natural gas from the U.S. Rockies to markets in the U.S. Midwest. The project has an anticipated in-service date of fourth quarter 2010 and is expected to cost approximately US\$600 million.
- Work continues on the US\$320 million Guadalajara pipeline project in Mexico. The 305-km (190-mile), 24 and 30-inch diameter natural gas pipeline is scheduled to be operational in March 2011. The pipeline will move natural gas from Manzanillo to Guadalajara, Mexico's second largest city. Construction was approximately 23 per cent complete at the end of June 2010.
- The 90 day open season for the Alaska Pipeline Project will conclude on July 30, 2010. Throughout this period, potential shippers have assessed the merits of the open season and the Alaska Pipeline Project has provided information to potential shippers in Alaska and Canada about the project's anticipated engineering design, commercial terms, estimated project costs and timelines.

Interested shippers will submit commercial bids prior to the close of the open season. It is typical with large, complex pipeline projects for bids from shippers to be conditional. The Alaska Pipeline Project will work with shippers to resolve any of these conditions within the project's control. Other key issues such as Alaska fiscal terms and natural gas resource access at Point Thomson will need to be resolved between shippers and the State of Alaska. The Alaska Pipeline Project is targeting to complete these discussions and announce the results of the open season by the end of 2010.

#### **Energy:**

- The \$700 million Halton Hills Generating Station is in the final stages of commissioning and is expected to be in service in third quarter 2010, on time and on budget. Power from the 683 megawatt (MW) natural gas-fired power plant near Halton Hills, Ontario will be sold to the Ontario Power Authority under a 20 year Clean Energy Supply contract.
- Construction is underway on the second phase of the Kibby Wind Power project. This phase includes an additional 22 turbines and is expected to be in-service in fourth quarter 2010. Once complete, the US\$350 million project will produce 132 MW of clean, renewable energy for the state of Maine. The first phase of the project began producing power in the fall of 2009.
- Construction on the 575 MW Coolidge Generating Station is over 60 per cent complete. Over 200 construction workers at the plant site have installed generators, transformers, 230 kilovolt (kV) transmission lines, exhaust stacks, water storage tanks, and permanent operations and wastewater treatment facilities. The US\$500 million generating station is anticipated to be in service by second quarter 2011.
- In May 2010, TransCanada announced that it had concluded a successful open season for the Zephyr Power Transmission project and had signed agreements for the full 3,000 MW of capacity with renewable energy developers in Wyoming. TransCanada continues to pursue the proposed Chinook power transmission line project and has extended its open season to December 16, 2010. Each project would be capable of delivering primarily renewable wind-generated power originating in Wyoming (Zephyr) and Montana (Chinook) to Nevada to access California and other desert southwest U.S. markets.

#### **Corporate:**

- On July 1, 2010, Russ Girling assumed the role of President and Chief Executive Officer and joined the TransCanada Board of Directors.

A number of other executive leadership team changes also became effective July 1. Alex Pourbaix was appointed to the role of President, Energy and Oil Pipelines; Greg Lohnes assumed the role of President, Natural Gas Pipelines; Don Marchand was appointed to the role of Executive Vice-President and Chief Financial Officer; and Dennis McConaghy assumed the role of Executive Vice-President, Corporate Development.

Don Wishart, Executive Vice-President, Operations and Major Projects; Sean McMaster, Executive Vice-President, Corporate and General Counsel; and Sarah Raiss, Executive Vice-President, Corporate Services continue in their current roles.

- The Board of Directors of TransCanada declared a quarterly dividend of \$0.40 per share for the quarter ending September 30, 2010, on TransCanada's outstanding common shares.
- In June 2010, TransCanada completed a public offering of 14 million Series 5 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares. The Series 5 shares were issued at a price of \$25 per share, resulting in gross proceeds of \$350 million. The initial dividend rate is fixed to January 30, 2016 at 4.40 per cent per annum paid quarterly.

Also in June 2010, TransCanada's wholly-owned subsidiary, TransCanada PipeLines Limited, successfully completed an offering of US\$500 million of 3.40 per cent Senior Notes due June 1, 2015, and US\$750 million of 6.10 per cent Senior Notes due June 1, 2040.

The net proceeds of these offerings are expected to be used to partially fund capital projects of TransCanada, for general corporate purposes and to reduce short term indebtedness of TransCanada and its affiliates.

- TransCanada is well positioned to fund its existing capital program through its growing internally-generated cash flow, its dividend reinvestment and share purchase plan, and its continued access to capital markets. TransCanada will also continue to examine opportunities for portfolio management, including a role for TC PipeLines, LP in financing its capital program.

#### **Teleconference – Audio and Slide Presentation:**

TransCanada will hold a teleconference and webcast to discuss its 2010 second quarter 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, including its \$22 billion capital program, before opening the call to questions from analysts and members of the media.

#### **Event:**

TransCanada 2010 second quarter financial results teleconference and webcast

#### **Date:**

Thursday, July 29, 2010

#### **Time:**

2:30 p.m. mountain daylight time (MDT) /4:30 p.m. eastern daylight time (EDT)

#### **How:**

Analysts, members of the media and other interested parties are invited to participate by calling 866.223.7781 or 416.340.8018 (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](http://www.transcanada.com).

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (EDT) August 5, 2010. Please call 800.408.3053 or 416.695.5800 (Toronto area) and enter pass code 3666830#.

With more than 50 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's network of wholly owned natural gas pipelines extends more than 60,000 kilometres (37,000 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 approximately 380 billion cubic feet of storage capacity. A growing independent power producer, TransCanada owns, or has interests in, over 11,700 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](http://www.transcanada.com)

### **Forward-Looking Information**

This news release may contain certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "should", "estimate", "project", "outlook", "forecast" or other similar words are used to identify such forward-looking information. Forward-looking statements in this document are intended to provide TransCanada securityholders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future financial and operations plans and outlook. Forward-looking statements in this document may include, among others, statements regarding the anticipated business prospects, projects and financial performance of TransCanada and its subsidiaries, expectations or projections about the future, and strategies and goals for growth and expansion. All forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted in these forward-looking statements. Factors that could cause actual results or events to differ materially from current expectations include, among others, the ability of TransCanada to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the operating performance of TransCanada's pipeline and energy assets, the availability and price of energy commodities, capacity payments, regulatory processes and decisions, 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 currency exchange rates, technological developments and economic conditions in North America. By its nature, forward-looking information is subject to various risks and uncertainties, which could cause TransCanada's actual results and experience to differ materially from the anticipated results or expectations expressed. Additional information on these and other factors is available in the reports filed by TransCanada with Canadian securities regulators and with the U.S. Securities and Exchange Commission (SEC). Readers are cautioned to not place undue reliance on this forward-looking information, which is given as of the date it is expressed in this news release or otherwise, and to not use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

### **Non-GAAP Measures**

TransCanada uses the measures Comparable Earnings, Comparable Earnings per Share, Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA), Comparable EBITDA, Earnings Before Interest and Taxes (EBIT), Comparable EBIT and Funds Generated from Operations in this news release.

These measures do not have any standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP). They are, therefore, considered to be non-GAAP measures and may not be comparable to similar measures presented by other entities. Management of TransCanada uses these non-GAAP measures to improve its ability to compare financial results among reporting periods and to enhance its understanding of operating performance, liquidity and ability to generate funds to finance operations. These non-GAAP measures are also provided to readers as additional information on TransCanada's operating performance, liquidity and ability to generate funds to finance operations.

EBITDA is an approximate measure of the Company's pre-tax operating cash flow. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, non-controlling interests and preferred share dividends. EBIT is a measure of the Company's earnings from ongoing operations. EBIT comprises earnings before deducting interest and other financial charges, income taxes, non-controlling interests and preferred share dividends.

Management uses the measures of Comparable Earnings, Comparable EBITDA and Comparable EBIT to better evaluate trends in the Company's underlying operations. Comparable Earnings, Comparable EBITDA and Comparable EBIT comprise Net Income Applicable to Common Shares, EBITDA and EBIT, respectively, adjusted for specific items that are significant, but are not reflective of the Company's underlying operations in the period. Specific items are subjective, however, management uses its judgement and informed decision-making when identifying items to be excluded in calculating Comparable Earnings, Comparable EBITDA and Comparable EBIT, some of which may recur. Specific items may include but are not limited to certain income

tax refunds and adjustments, gains or losses on sales of assets, legal and bankruptcy settlements, and certain fair value adjustments. The table in the Consolidated Results of Operations section in the Management's Discussion and Analysis presents a reconciliation of Comparable Earnings, Comparable EBITDA, Comparable EBIT and EBIT to Net Income and Net Income Applicable to Common Shares. Comparable Earnings per Share is calculated by dividing Comparable Earnings by the weighted average number of common shares outstanding for the period.

Funds Generated from Operations comprises Net Cash Provided by Operations before changes in operating working capital. A reconciliation of Funds Generated from Operations to Net Cash Provided by Operations is presented in the Second Quarter 2010 Financial Highlights table in this news release.

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## Second Quarter 2010 Financial Highlights

### Operating Results

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
<b>Revenues</b>	<b>1,923</b>	1,984	<b>3,878</b>	4,146
<b>Comparable EBITDA<sup>(1)</sup></b>	<b>928</b>	1,017	<b>1,929</b>	2,148
<b>Comparable EBIT<sup>(1)</sup></b>	<b>587</b>	672	<b>1,245</b>	1,457
<b>EBIT<sup>(1)</sup></b>	<b>602</b>	665	<b>1,211</b>	1,437
<b>Net Income</b>	<b>295</b>	314	<b>598</b>	648
<b>Net Income Applicable to Common Shares</b>	<b>285</b>	314	<b>581</b>	648
<b>Comparable Earnings<sup>(1)</sup></b>	<b>275</b>	319	<b>603</b>	662
<b>Cash Flows</b>				
Funds generated from operations <sup>(1)</sup>	<b>935</b>	692	<b>1,658</b>	1,458
(Increase)/decrease in operating working capital	<b>(310)</b>	246	<b>(201)</b>	328
Net cash provided by operations	<b>625</b>	938	<b>1,457</b>	1,786
<b>Capital Expenditures</b>	<b>992</b>	1,263	<b>2,268</b>	2,386
<b>Acquisitions, Net of Cash Acquired</b>	<b>-</b>	115	<b>-</b>	249

### Common Share Statistics

<i>(unaudited)</i>	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
<b>Net Income Per Share - Basic</b>	<b>\$0.41</b>	\$0.50	<b>\$0.84</b>	\$1.04
<b>Comparable Earnings Per Share<sup>(1)</sup></b>	<b>\$0.40</b>	\$0.51	<b>\$0.87</b>	\$1.06
<b>Dividends Declared Per Share</b>	<b>\$0.40</b>	\$0.38	<b>\$0.80</b>	\$0.76
<b>Basic Common Shares Outstanding</b> (millions)				
Average for the period	<b>689</b>	624	<b>688</b>	621
End of period	<b>690</b>	679	<b>690</b>	679

<sup>(1)</sup> Refer to the Non-GAAP Measures section in this news release for further discussion of comparable EBITDA, comparable EBIT, EBIT, comparable earnings, funds generated from operations and comparable earnings per share.

# Quarterly Report to Shareholders

## **Management's Discussion and Analysis**

Management's Discussion and Analysis (MD&A) dated July 29, 2010 should be read in conjunction with the accompanying unaudited Consolidated Financial Statements of TransCanada Corporation (TransCanada or the Company) for the three and six months ended June 30, 2010. It should also be read in conjunction with the audited Consolidated Financial Statements and notes thereto, and the MD&A contained in TransCanada's 2009 Annual Report for the year ended December 31, 2009. Additional information relating to TransCanada, including the Company's Annual Information Form and other continuous disclosure documents, is available on SEDAR at [www.sedar.com](http://www.sedar.com) under TransCanada Corporation. Unless otherwise indicated, "TransCanada" or "the Company" includes TransCanada Corporation and its subsidiaries. Amounts are stated in Canadian dollars unless otherwise indicated. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in the Glossary of Terms contained in TransCanada's 2009 Annual Report.

## **Forward-Looking Information**

This MD&A may contain certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "should", "estimate", "project", "outlook", "forecast" or other similar words are used to identify such forward-looking information. 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. Forward-looking statements in this document may include, among others, statements regarding the anticipated business prospects, projects and financial performance of TransCanada and its subsidiaries, expectations or projections about the future, strategies and goals for growth and expansion, expected and future cash flows, costs, schedules (including anticipated construction and completion dates), operating and financial results, and expected impact of future commitments and contingent liabilities. All forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted in these forward-looking statements. Factors that could cause actual results or events to differ materially from current expectations include, among others, the ability of TransCanada to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the operating performance of the Company's pipeline and energy assets, the availability and price of energy commodities, capacity payments, regulatory processes and decisions, 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 currency exchange rates, technological developments and economic conditions in North America. By its nature, forward-looking information is subject to various risks and uncertainties, which could cause TransCanada's actual results and experience to differ materially from the anticipated results or expectations expressed. Additional information on these and other factors is available in the reports filed by TransCanada with Canadian securities regulators and with the U.S. Securities and Exchange Commission (SEC). 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 MD&A or otherwise, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to update publicly



or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

### **Non-GAAP Measures**

TransCanada uses the measures Comparable Earnings, Comparable Earnings Per Share, Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA), Comparable EBITDA, Earnings Before Interest and Taxes (EBIT), Comparable EBIT and Funds Generated from Operations in this MD&A. These measures do not have any standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP). They are, therefore, considered to be non-GAAP measures and may not be comparable to similar measures presented by other entities. Management of TransCanada uses these non-GAAP measures to improve its ability to compare financial results among reporting periods and to enhance its understanding of operating performance, liquidity and ability to generate funds to finance operations. These non-GAAP measures are also provided to readers as additional information on TransCanada's operating performance, liquidity and ability to generate funds to finance operations.

EBITDA is an approximate measure of the Company's pre-tax operating cash flow. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, non-controlling interests and preferred share dividends. EBIT is a measure of the Company's earnings from ongoing operations. EBIT comprises earnings before deducting interest and other financial charges, income taxes, non-controlling interests and preferred share dividends.

Management uses the measures of Comparable Earnings, Comparable EBITDA and Comparable EBIT to better evaluate trends in the Company's underlying operations. Comparable Earnings, Comparable EBITDA and Comparable EBIT comprise Net Income Applicable to Common Shares, EBITDA and EBIT, respectively, adjusted for specific items that are significant but are not reflective of the Company's underlying operations in the period. Specific items are subjective, however, management uses its judgement and informed decision-making when identifying items to be excluded in calculating Comparable Earnings, Comparable EBITDA and Comparable EBIT, some of which may recur. Specific items may include but are not limited to certain income tax refunds and adjustments, gains or losses on sales of assets, legal and bankruptcy settlements, and certain fair value adjustments. The table in the Consolidated Results of Operations section of this MD&A presents a reconciliation of Comparable Earnings, Comparable EBITDA, Comparable EBIT and EBIT to Net Income and Net Income Applicable to Common Shares. Comparable Earnings Per Share is calculated by dividing Comparable Earnings by the weighted average number of common shares outstanding for the period.

Funds Generated from Operations comprises Net Cash Provided by Operations before changes in operating working capital. A reconciliation of Funds Generated from Operations to Net Cash Provided by Operations is presented in the Funds Generated from Operations table in the Liquidity and Capital Resources section of this MD&A.

## Consolidated Results of Operations

### Reconciliation of Comparable Earnings, Comparable EBITDA, Comparable EBIT and EBIT to Net Income

For the three months ended June 30  
(unaudited)(millions of dollars  
except per share amounts)

	Pipelines		Energy		Corporate		Total	
	2010	2009	2010	2009	2010	2009	2010	2009
<b>Comparable EBITDA<sup>(1)</sup></b>	<b>696</b>	<b>747</b>	<b>254</b>	<b>301</b>	<b>(22)</b>	<b>(31)</b>	<b>928</b>	<b>1,017</b>
Depreciation and amortization	(251)	(258)	(90)	(87)	-	-	(341)	(345)
<b>Comparable EBIT<sup>(1)</sup></b>	<b>445</b>	<b>489</b>	<b>164</b>	<b>214</b>	<b>(22)</b>	<b>(31)</b>	<b>587</b>	<b>672</b>
Specific items:								
Fair value adjustments of U.S. Power derivative contracts	-	-	9	-	-	-	9	-
Fair value adjustments of natural gas inventory in storage and forward contracts	-	-	6	(7)	-	-	6	(7)
<b>EBIT<sup>(1)</sup></b>	<b>445</b>	<b>489</b>	<b>179</b>	<b>207</b>	<b>(22)</b>	<b>(31)</b>	<b>602</b>	<b>665</b>
Interest expense							(187)	(259)
Interest expense of joint ventures							(15)	(16)
Interest income and other							(18)	34
Income taxes							(65)	(97)
Non-controlling interests							(22)	(13)
<b>Net Income</b>							<b>295</b>	<b>314</b>
Preferred share dividends							(10)	-
<b>Net Income Applicable to Common Shares</b>							<b>285</b>	<b>314</b>
Specific items (net of tax):								
Fair value adjustments of U.S. Power derivative contracts							(6)	-
Fair value adjustments of natural gas inventory in storage and forward contracts							(4)	5
<b>Comparable Earnings<sup>(1)</sup></b>							<b>275</b>	<b>319</b>
<b>Net Income Per Share – Basic and Diluted<sup>(2)</sup></b>							<b>\$0.41</b>	<b>\$0.50</b>

<sup>(1)</sup> Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA, Comparable EBIT, EBIT, Comparable Earnings and Comparable Earnings Per Share.

<sup>(2)</sup> For the three months ended June 30  
(unaudited)

	2010	2009
<b>Net Income Per Share</b>	<b>\$0.41</b>	<b>\$0.50</b>
Specific items (net of tax):		
Fair value adjustments of U.S. Power derivative contracts	(0.01)	-
Fair value adjustments of natural gas inventory in storage and forward contracts	-	0.01
<b>Comparable Earnings Per Share<sup>(1)</sup></b>	<b>\$0.40</b>	<b>\$0.51</b>

For the six months ended June 30  
(unaudited)(millions of dollars  
except per share amounts)

	Pipelines		Energy		Corporate		Total	
	2010	2009	2010	2009	2010	2009	2010	2009
<b>Comparable EBITDA<sup>(1)</sup></b>	<b>1,464</b>	1,618	<b>513</b>	591	<b>(48)</b>	(61)	<b>1,929</b>	2,148
Depreciation and amortization	(504)	(518)	(180)	(173)	-	-	(684)	(691)
<b>Comparable EBIT<sup>(1)</sup></b>	<b>960</b>	1,100	<b>333</b>	418	<b>(48)</b>	(61)	<b>1,245</b>	1,457
Specific items:								
Fair value adjustments of U.S. Power derivative contracts	-	-	(19)	-	-	-	(19)	-
Fair value adjustments of natural gas inventory in storage and forward contracts	-	-	(15)	(20)	-	-	(15)	(20)
<b>EBIT<sup>(1)</sup></b>	<b>960</b>	1,100	<b>299</b>	398	<b>(48)</b>	(61)	<b>1,211</b>	1,437
Interest expense							(369)	(554)
Interest expense of joint ventures							(31)	(30)
Interest income and other							6	56
Income taxes							(166)	(213)
Non-controlling interests							(53)	(48)
<b>Net Income</b>							<b>598</b>	648
Preferred share dividends							(17)	-
<b>Net Income Applicable to Common Shares</b>							<b>581</b>	648
Specific items (net of tax):								
Fair value adjustments of U.S. Power derivative contracts							11	-
Fair value adjustments of natural gas inventory in storage and forward contracts							11	14
<b>Comparable Earnings<sup>(1)</sup></b>							<b>603</b>	662
<b>Net Income Per Share – Basic and Diluted<sup>(2)</sup></b>							<b>\$0.84</b>	\$1.04

<sup>(1)</sup> Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA, Comparable EBIT, EBIT, Comparable Earnings and Comparable Earnings Per Share.

<sup>(2)</sup> For the six months ended June 30  
(unaudited)

	2010	2009
<b>Net Income Per Share</b>	<b>\$0.84</b>	\$1.04
Specific items (net of tax):		
Fair value adjustments of U.S. Power derivative contracts	0.02	-
Fair value adjustments of natural gas inventory in storage and forward contracts	0.01	0.02
<b>Comparable Earnings Per Share<sup>(1)</sup></b>	<b>\$0.87</b>	\$1.06

TransCanada's Net Income in second quarter 2010 was \$295 million and Net Income Applicable to Common Shares was \$285 million or \$0.41 per share compared to \$314 million or \$0.50 per share in second quarter 2009. The \$29 million decrease in Net Income Applicable to Common Shares reflected:

- decreased EBIT from Pipelines primarily due to the negative impact of a weaker U.S. dollar;
- decreased EBIT from Energy primarily due to lower volumes and increased operating costs at Bruce A, lower realized prices partially offset by higher volumes at Bruce B, reduced proprietary and third party storage revenues for Natural Gas Storage and the negative impact of a weaker U.S. dollar, partially offset by higher realized power prices in Western Power and increased capacity revenue in U.S. Power;
- decreased Interest Expense primarily due to increased capitalized interest and the positive effect of a weaker U.S. dollar on U.S. dollar-denominated interest expense, partially offset by losses in second quarter 2010 compared to gains in 2009 from changes in the fair value of derivatives used to manage the Company's exposure to rising interest rates;

- a negative impact on Interest Income and Other of losses in second quarter 2010 compared to gains in 2009 from derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and from the translation of working capital balances due to the strengthening U.S. dollar; and
- decreased Income Taxes due to lower pre-tax earnings and the net positive impact from income tax rate differentials and other income tax adjustments.

The combined negative impact of losses in second quarter 2010 compared to gains in second quarter 2009 for the interest rate and foreign exchange rate derivatives that did not qualify as hedges for accounting purposes and the translation of working capital balances amounted to \$58 million or \$0.08 per share.

Net Income Per Share in second quarter 2010 was also reduced by \$0.05 per share due to a ten per cent increase in the average number of common shares outstanding in second quarter 2010 compared to second quarter 2009 following the Company's issuance of 58.4 million common shares in second quarter 2009. A portion of the net proceeds from the share issue were used to partially fund the Company's current \$22 billion capital expansion program.

Comparable Earnings in second quarter 2010 were \$275 million or \$0.40 per share compared to \$319 million or \$0.51 per share for the same period in 2009. Comparable Earnings in second quarter 2010 excluded net unrealized after tax gains of \$6 million (\$9 million pre-tax) resulting from changes in the fair value of certain U.S. Power derivative contracts. Effective January 1, 2010, these unrealized gains have been removed from Comparable Earnings as they are not expected to be representative of amounts that will be realized on settlement of the contracts. Comparative amounts in 2009 were not material and therefore were not excluded from the computation of Comparable Earnings. Comparable Earnings in second quarter 2010 and 2009 also excluded net unrealized after tax gains of \$4 million (\$6 million pre-tax) and after tax losses of \$5 million (\$7 million pre-tax), respectively, resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. Pipelines and Energy EBIT is considerably offset by the impact on U.S. dollar-denominated interest expense. The resultant net exposure is managed using derivatives, effectively further reducing the Company's exposure to changes in foreign exchange rates. The average U.S. dollar exchange rate for the three and six months ended June 30, 2010 was 1.03 and 1.03, respectively (2009 - 1.17 and 1.21, respectively).

TransCanada's Net Income in the first six months of 2010 was \$598 million and Net Income Applicable to Common Shares was \$581 million or \$0.84 per share compared to \$648 million or \$1.04 per share for the same period in 2009. The \$67 million decrease in Net Income Applicable to Common Shares reflected:

- decreased EBIT from Pipelines primarily due to the negative impact of a weaker U.S. dollar, higher business development costs relating to the Alaska pipeline project and lower revenues from certain U.S. pipelines, partially offset by reduced operating, maintenance and administration (OM&A) costs;
- decreased EBIT from Energy primarily due to reduced volumes and higher operating costs at Bruce A, lower realized prices partially offset by higher volumes at Bruce B, lower overall realized power prices at Western Power and reduced earnings at Bécancour, partially offset by increased capacity revenue from U.S. Power and incremental earnings from Portlands Energy which went into service in April 2009;

- decreased Interest Expense primarily due to increased capitalized interest and the positive effect of a weaker U.S. dollar on U.S. dollar-denominated interest expense, partially offset by losses in 2010 compared to gains in 2009 from changes in the fair value of derivatives used to manage the Company's exposure to rising interest rates;
- the negative impact on Interest Income and Other due to losses in 2010 compared to gains in 2009 from derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and from the translation of working capital balances due to the strengthening U.S. dollar; and
- decreased Income Taxes due to lower pre-tax earnings and the net positive impact from income tax rate differentials and other income tax adjustments.

Net Income Per Share in the first six months of 2010 was also reduced by \$0.10 per share due to an 11 per cent increase in the average number of common shares outstanding compared to the same period in 2009 following the Company's issuance of 58.4 million common shares in second quarter 2009.

Comparable Earnings in the first six months of 2010 were \$603 million or \$0.87 per share compared to \$662 million or \$1.06 per share for the same period in 2009. Comparable Earnings for the first six months of 2010 excluded net unrealized after tax losses of \$11 million (\$19 million pre-tax) resulting from changes in the fair value of certain U.S. Power derivative contracts. Comparative amounts in 2009 were not material and therefore were not excluded from the computation of Comparable Earnings. Comparable Earnings in the first six months of 2010 and 2009 also excluded net unrealized after tax losses of \$11 million (\$15 million pre-tax) and \$14 million (\$20 million pre-tax), respectively, resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

Results from each of the segments for the first three and six months in 2010 are discussed further in the Pipelines and Energy sections of this MD&A.

## Pipelines

Pipelines' Comparable EBIT and EBIT were \$445 million and \$1.0 billion in the three and six month periods ended June 30, 2010, respectively, compared to \$489 million and \$1.1 billion for the same periods in 2009.

### Pipelines Results

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
<b>Canadian Pipelines</b>				
Canadian Mainline	263	288	528	572
Alberta System	176	177	351	345
Foothills	35	34	68	68
Other (TQM, Ventures LP)	14	12	27	31
<b>Canadian Pipelines Comparable EBITDA<sup>(1)</sup></b>	<b>488</b>	<b>511</b>	<b>974</b>	<b>1,016</b>
<b>U.S. Pipelines</b>				
ANR	61	73	181	206
GTN <sup>(2)</sup>	41	49	86	110
Great Lakes	26	33	59	77
PipeLines LP <sup>(2)(3)</sup>	22	21	48	50
Iroquois	18	21	37	44
Portland <sup>(4)</sup>	1	2	11	16
International (Tamazunchale, TransGas, Gas Pacifico/INNERGY)	15	14	25	27
General, administrative and support costs <sup>(5)</sup>	(3)	(3)	(9)	(6)
Non-controlling interests <sup>(6)</sup>	37	34	85	94
<b>U.S. Pipelines Comparable EBITDA<sup>(1)</sup></b>	<b>218</b>	<b>244</b>	<b>523</b>	<b>618</b>
<b>Business Development Comparable EBITDA<sup>(1)</sup></b>	<b>(10)</b>	<b>(8)</b>	<b>(33)</b>	<b>(16)</b>
<b>Pipelines Comparable EBITDA<sup>(1)</sup></b>	<b>696</b>	<b>747</b>	<b>1,464</b>	<b>1,618</b>
Depreciation and amortization	(251)	(258)	(504)	(518)
<b>Pipelines Comparable EBIT and EBIT<sup>(1)</sup></b>	<b>445</b>	<b>489</b>	<b>960</b>	<b>1,100</b>

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA, Comparable EBIT and EBIT.

(2) GTN's results include North Baja until July 1, 2009 when it was sold to PipeLines LP.

(3) PipeLines LP's results reflect TransCanada's ownership interest in PipeLines LP of 38.2 per cent in the first six months of 2010 (first six months of 2009 – 32.1 per cent).

(4) Portland's results reflect TransCanada's 61.7 per cent ownership interest.

(5) Represents certain costs associated with supporting the Company's Canadian and U.S. Pipelines.

(6) Non-controlling interests reflects Comparable EBITDA for the portions of PipeLines LP and Portland not owned by TransCanada.

### Net Income for Wholly Owned Canadian Pipelines

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Canadian Mainline	64	67	130	133
Alberta System	37	40	75	79
Foothills	7	6	13	12

#### Canadian Pipelines

Canadian Mainline's net income for the three and six months ended June 30, 2010 decreased \$3 million for both periods primarily as a result of lower incentive earnings and a lower rate of return on common equity (ROE) as determined by the National Energy Board (NEB), of 8.52 per cent in 2010 compared to 8.57 per cent in 2009.

Canadian Mainline's Comparable EBITDA for the three and six months ended June 30, 2010 of \$263 million and \$528 million, respectively, decreased \$25 million and \$44 million, respectively, compared to the same periods in 2009 primarily due to lower revenues as a result of lower income tax and financial charge components in the 2010 tolls, which are recovered on a flow-through basis and do not impact net income. The decrease in financial charges was primarily due to higher cost historic debt that matured in 2009 and early 2010.

The Alberta System's net income was \$37 million in second quarter 2010 and \$75 million for the first six months of 2010 compared to \$40 million and \$79 million for the same periods in 2009. The impact of a higher average investment base in 2010 was more than offset by lower earnings due to the expiration of the 2008-2009 Revenue Requirement Settlement. Net income for the first six months of 2010 currently reflects an ROE of 8.75 per cent on a deemed common equity of 35 per cent. Upon regulatory approval, which is expected to be received in third quarter 2010, TransCanada will record the impact of a three year Alberta System settlement with shippers, which includes a 9.70 per cent ROE on a deemed common equity of 40 per cent, retroactive to January 1, 2010. The Company expects this settlement, when approved, to increase net income by approximately \$20 million for the first six months of 2010.

The Alberta System's Comparable EBITDA was \$176 million in second quarter 2010 and \$351 million for the first six months of 2010 compared to \$177 million and \$345 million for the same periods in 2009. The increase in the six month period was primarily due to higher revenues as a result of a higher return associated with an increased average investment base and a recovery of increased depreciation and income taxes, partially offset by lower earnings due to the expiration of the 2008-2009 Revenue Requirement Settlement. Depreciation and income taxes are recovered on a flow-through basis and do not impact net income.

Comparable EBITDA from Other Canadian Pipelines was \$14 million in second quarter 2010 and \$27 million for the first six months of 2010, compared to \$12 million and \$31 million for the same periods in 2009. The decrease in the six months ended June 30, 2010 was primarily due to an adjustment recorded in second quarter 2009 for an NEB decision to retroactively increase TQM's allowed rate of return on capital for 2008 and 2007.

#### *U.S. Pipelines*

ANR's Comparable EBITDA for the three and six months ended June 30, 2010 was \$61 million and \$181 million, respectively, compared to \$73 million and \$206 million for the same periods in 2009. The decreases were primarily due to the negative impact of a weaker U.S. dollar and lower transportation and storage revenue, partially offset by lower OM&A costs.

GTN's Comparable EBITDA for the three and six months ended June 30, 2010 decreased \$8 million and \$24 million, respectively, from the same periods in 2009 primarily due to the sale of North Baja to PipeLines LP in July 2009 and the negative impact of a weaker U.S. dollar, partially offset by higher revenues as a result of new long-term firm contracts and lower OM&A costs in 2010.

Comparable EBITDA for the remainder of the U.S. Pipelines was \$116 million and \$256 million for the three and six months ended June 30, 2010, respectively, compared to \$122 million and \$302 million for the same periods in 2009. The decreases were primarily due to the negative impact of a weaker U.S. dollar and lower revenues from Great Lakes and Portland, partially offset by increased PipeLines LP earnings which reflected the acquisition of North Baja in July 2009.

#### *Business Development*

Pipelines' Business Development Comparable EBITDA decreased \$2 million and \$17 million in the three and six months ended June 30, 2010 compared to the same periods in 2009 primarily due to higher business development costs related to the continued advancement of the Alaska pipeline

project, net of recoveries. The State of Alaska has agreed to reimburse certain of TransCanada's eligible pre-construction costs, as they are incurred and approved by the state, to a maximum of US\$500 million. The State of Alaska will reimburse up to 50 per cent of the eligible costs incurred prior to the close of the first binding open season. The Company is currently holding an open season that will close on July 30, 2010. Once the first binding open season is closed, the State will reimburse up to 90 per cent of the eligible costs. Together with applicable expenses, such reimbursements are shared proportionately with ExxonMobil, TransCanada's joint venture partner in developing the Alaska pipeline project.

### Operating Statistics

Six months ended June 30 (unaudited)	Canadian Mainline <sup>(1)</sup>		Alberta System <sup>(2)</sup>		Foothills		ANR <sup>(3)</sup>		GTN <sup>(3)</sup>	
	2010	2009	2010	2009	2010	2009	2010	2009	2010	2009
Average investment base (\$millions)	6,572	6,566	4,975	4,671	666	717	n/a	n/a	n/a	n/a
Delivery volumes (Bcf)										
Total	844	1,130	1,723	1,827	680	562	795	867	389	344
Average per day	4.7	6.2	9.5	10.1	3.8	3.1	4.4	4.8	2.2	1.9

- (1) Canadian Mainline's throughput volumes in the above table reflect physical deliveries to domestic and export markets. Throughput volumes reported in previous years reflected contract deliveries, however, customer contracting patterns have changed in recent years making physical deliveries a better measure of system utilization. Canadian Mainline's physical receipts originating at the Alberta border and in Saskatchewan for the six months ended June 30, 2010 were 645 billion cubic feet (Bcf) (2009 – 883 Bcf); average per day was 3.6 Bcf (2009 – 4.9 Bcf).
- (2) Field receipt volumes for the Alberta System for the six months ended June 30, 2010 were 1,740 Bcf (2009 – 1,848 Bcf); average per day was 9.6 Bcf (2009 – 10.2 Bcf).
- (3) ANR's and GTN's results are not impacted by average investment base as these systems operate under fixed rate models approved by the U.S. Federal Energy Regulatory Commission.

### Mackenzie Gas Pipeline Project

As at June 30, 2010, TransCanada had advanced \$144 million to the Aboriginal Pipeline Group (APG) with respect to the Mackenzie Gas Pipeline Project (MGP). TransCanada and the other co-venture companies involved in the MGP continue to pursue approval of the proposed project, focusing on obtaining regulatory approval and the Canadian government's support of an acceptable fiscal framework. The NEB recently concluded final argument hearings for the project and is expected to release its conclusions on the project's application in September 2010. Project timing continues to be uncertain. In the event the co-venture group is unable to reach an agreement with the government on an acceptable fiscal framework, the parties will need to determine the appropriate next steps for the project. For TransCanada, this may result in a reassessment of the carrying amount of the APG advances.

### Energy

Energy's Comparable EBIT was \$164 million in second quarter 2010 compared to \$214 million in second quarter 2009. Comparable EBIT in second quarter 2010 excluded net unrealized gains of \$9 million resulting from changes in the fair value of certain U.S. Power derivative contracts. Comparable EBIT in second quarter 2010 and 2009 also excluded net unrealized gains of \$6 million and net unrealized losses of \$7 million, respectively, from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

Energy's Comparable EBIT was \$333 million in the first six months of 2010 compared to \$418 million in the same six months of 2009. Comparable EBIT excluded net unrealized losses of \$19 million resulting from changes in the fair value of certain U.S. Power derivative contracts. Comparable EBIT in the first six months of 2010 and 2009 also excluded net unrealized losses of \$15 million and \$20 million, respectively, from changes in the fair value of proprietary natural gas inventory in storage and



natural gas forward purchase and sale contracts. Items excluded from Comparable Earnings are discussed further under the headings U.S. Power and Natural Gas Storage in this section.

### Energy Results

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
<b>Canadian Power</b>				
Western Power	85	59	127	152
Eastern Power <sup>(1)</sup>	46	60	98	112
Bruce Power	47	102	110	201
General, administrative and support costs	(5)	(11)	(15)	(19)
<b>Canadian Power Comparable EBITDA<sup>(2)</sup></b>	<b>173</b>	<b>210</b>	<b>320</b>	<b>446</b>
<b>U.S. Power</b>				
Northeast Power <sup>(3)</sup>	81	76	156	118
General, administrative and support costs	(9)	(11)	(18)	(23)
<b>U.S. Power Comparable EBITDA<sup>(2)</sup></b>	<b>72</b>	<b>65</b>	<b>138</b>	<b>95</b>
<b>Natural Gas Storage</b>				
Alberta Storage	20	36	73	75
General, administrative and support costs	(2)	(2)	(4)	(5)
<b>Natural Gas Storage Comparable EBITDA<sup>(2)</sup></b>	<b>18</b>	<b>34</b>	<b>69</b>	<b>70</b>
<b>Business Development Comparable EBITDA<sup>(2)</sup></b>	<b>(9)</b>	<b>(8)</b>	<b>(14)</b>	<b>(20)</b>
<b>Energy Comparable EBITDA<sup>(2)</sup></b>	<b>254</b>	<b>301</b>	<b>513</b>	<b>591</b>
Depreciation and amortization	(90)	(87)	(180)	(173)
<b>Energy Comparable EBIT<sup>(2)</sup></b>	<b>164</b>	<b>214</b>	<b>333</b>	<b>418</b>
Specific items:				
Fair value adjustments of U.S. Power derivative contracts	9	-	(19)	-
Fair value adjustments of natural gas inventory in storage and forward contracts	6	(7)	(15)	(20)
<b>Energy EBIT<sup>(2)</sup></b>	<b>179</b>	<b>207</b>	<b>299</b>	<b>398</b>

(1) Includes Portlands Energy effective April 2009.

(2) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA, Comparable EBIT and EBIT.

(3) Includes phase one of Kibby Wind effective October 2009.

*Canadian Power***Western and Eastern Canadian Power Comparable EBITDA<sup>(1)(2)</sup>**

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Revenues				
Western power	202	174	366	389
Eastern power	65	71	132	140
Other <sup>(3)</sup>	15	30	37	42
	<u>282</u>	<u>275</u>	<u>535</u>	<u>571</u>
Commodity Purchases Resold				
Western power	(99)	(109)	(205)	(207)
Other <sup>(3)(4)</sup>	(7)	(6)	(12)	(15)
	<u>(106)</u>	<u>(115)</u>	<u>(217)</u>	<u>(222)</u>
Plant operating costs and other	(45)	(43)	(93)	(87)
General, administrative and support costs	(5)	(11)	(15)	(19)
Other income	-	2	-	2
<b>Comparable EBITDA<sup>(1)</sup></b>	<b><u>126</u></b>	<b><u>108</u></b>	<b><u>210</u></b>	<b><u>245</u></b>

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA.

(2) Includes Portlands Energy effective April 2009.

(3) Includes sales of excess natural gas purchased for generation and thermal carbon black. Effective January 1, 2010, the net impact of derivatives used to purchase and sell natural gas to manage Western and Eastern Power's assets is presented on a net basis in Other Revenues. Comparative results for 2009 reflect amounts reclassified from Other Commodity Purchases Resold to Other Revenues.

(4) Includes the cost of excess natural gas not used in operations.

**Western and Eastern Canadian Power Operating Statistics<sup>(1)</sup>**

<i>(unaudited)</i>	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
<b>Sales Volumes (GWh)</b>				
Supply				
Generation				
Western Power	594	572	1,179	1,177
Eastern Power	395	421	824	776
Purchased				
Sundance A & B and Sheerness PPAs	2,459	2,725	5,114	5,165
Other purchases	73	122	222	307
	<u>3,521</u>	<u>3,840</u>	<u>7,339</u>	<u>7,425</u>
Sales				
Contracted				
Western Power	2,573	2,597	4,842	4,650
Eastern Power	395	419	840	810
Spot				
Western Power	553	824	1,657	1,965
	<u>3,521</u>	<u>3,840</u>	<u>7,339</u>	<u>7,425</u>
<b>Plant Availability</b>				
Western Power <sup>(2)</sup>	94%	93%	94%	92%
Eastern Power	97%	98%	97%	98%

(1) Includes Portlands Energy effective April 2009.

(2) Excludes facilities that provide power to TransCanada under PPAs.

Western Power's Comparable EBITDA of \$85 million and Power Revenues of \$202 million in second quarter 2010 increased \$26 million and \$28 million, respectively, compared to the same period in 2009, primarily due to increased revenues from the Alberta power portfolio resulting from higher realized power prices. Average spot market power prices in Alberta increased 150 per cent to \$80 per megawatt

hour (MWh) in second quarter 2010 compared to \$32 per MWh in second quarter 2009. Spot market sales represented 18 per cent of Western Power's total sales in second quarter 2010.

Western Power's Comparable EBITDA of \$127 million and Power Revenues of \$366 million in the first six months of 2010 decreased \$25 million and \$23 million, respectively, compared to the same period in 2009, primarily due to lower overall realized power prices.

Eastern Power's Comparable EBITDA of \$46 million and \$98 million for the three and six months ended June 30, 2010, decreased \$14 million compared to each of the same periods in 2009. Decreased revenues due to lower contracted earnings from Bécancour and unfavourable wind conditions at Cartier Wind were partially offset by incremental earnings from Portlands Energy, which went into service in April 2009. Results from Bécancour are consistent with the expected contracted earnings according to the original electricity supply contract with Hydro-Québec and are variable due to the timing of maintenance cycles under the contract.

Western Power manages the sale of its supply volumes on a portfolio basis. A portion of its supply is sold into the spot market to assure supply in the event of an unexpected plant outage. The overall amount of spot market volumes is dependent upon the ability to transact in forward sales markets at acceptable contract terms. This approach to portfolio management helps to minimize costs in situations where Western Power would otherwise have to purchase electricity in the open market to fulfill its contractual sales obligations. Approximately 82 per cent of Western Power sales volumes were sold under contract in second quarter 2010, compared to 76 per cent in second quarter 2009. To reduce its exposure to spot market prices on uncontracted volumes, as at June 30, 2010, Western Power had entered into fixed-price power sales contracts to sell approximately 4,700 gigawatt hours (GWh) for the remainder of 2010 and 6,700 GWh for 2011.

Eastern Power is focused on selling power under long-term contracts. In second quarter 2010 and 2009, all of Eastern Power's sales volumes were sold under contract and are expected to continue to be 100 per cent sold under contract for 2010 and 2011.

**Bruce Power Results**

(TransCanada's proportionate share)  
(unaudited)

(millions of dollars unless otherwise indicated)

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Revenues <sup>(1)</sup>	197	240	422	461
Operating Expenses	(150)	(138)	(312)	(260)
<b>Comparable EBITDA<sup>(2)</sup></b>	<b>47</b>	<b>102</b>	<b>110</b>	<b>201</b>
<b>Bruce A Comparable EBITDA<sup>(2)</sup></b>	<b>10</b>	<b>47</b>	<b>23</b>	<b>88</b>
<b>Bruce B Comparable EBITDA<sup>(2)</sup></b>	<b>37</b>	<b>55</b>	<b>87</b>	<b>113</b>
<b>Comparable EBITDA<sup>(2)</sup></b>	<b>47</b>	<b>102</b>	<b>110</b>	<b>201</b>
<b>Bruce Power – Other Information</b>				
Plant availability				
Bruce A	72%	100%	69%	99%
Bruce B	86%	75%	92%	86%
Combined Bruce Power	82%	83%	85%	90%
Planned outage days				
Bruce A	25	-	60	-
Bruce B	47	45	47	45
Unplanned outage days				
Bruce A	22	-	48	5
Bruce B	-	33	6	41
Sales volumes (GWh)				
Bruce A	1,121	1,563	2,110	3,058
Bruce B	1,944	1,662	4,099	3,801
	<b>3,065</b>	<b>3,225</b>	<b>6,209</b>	<b>6,859</b>
Results per MWh				
Bruce A power revenues	\$65	\$64	\$64	\$64
Bruce B power revenues <sup>(3)</sup>	\$59	\$70	\$58	\$63
Combined Bruce Power revenues	\$60	\$68	\$60	\$63
Percentage of Bruce B output sold to spot market <sup>(4)</sup>	75%	40%	77%	38%

(1) Revenues include Bruce A's fuel cost recoveries of \$9 million and \$14 million for the three and six months ended June 30, 2010, respectively (2009 – \$11 million and \$21 million). Revenues also include Bruce B unrealized losses of nil and \$1 million as a result of changes in the fair value of power derivatives for the three and six months ended June 30, 2010, respectively (2009 – gains of nil and \$2 million).

(2) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA.

(3) Includes revenues received under the floor price mechanism and contract settlements.

(4) All of Bruce B's output is covered by the floor price mechanism, including volumes sold to the spot market.

TransCanada's proportionate share of Bruce Power's Comparable EBITDA decreased \$55 million to \$47 million in second quarter 2010 compared to \$102 million in second quarter 2009.

TransCanada's proportionate share of Bruce A's Comparable EBITDA decreased \$37 million to \$10 million in second quarter 2010 compared to \$47 million in second quarter 2009 as a result of decreased volumes and higher operating costs due to increased planned and unplanned outage days. Bruce A's plant availability in second quarter 2010 was 72 per cent as a result of 47 outage days compared to an availability of 100 per cent and no outage days in the same period in 2009.

TransCanada's proportionate share of Bruce B's Comparable EBITDA decreased \$18 million to \$37 million in second quarter 2010 compared to \$55 million in second quarter 2009 primarily due to lower realized prices resulting from the expiration of fixed-price contracts at higher prices, partially offset by higher volumes due to a decrease in outage days.

In second quarter 2009, Bruce B's contract with the Ontario Power Authority (OPA) was amended such that, beginning in 2009, annual net payments received under the floor price mechanism will not

be subject to repayment in future years. The support payments recognized by Bruce B in second quarter 2009 included an amount related to first quarter 2009. This amount has been excluded from the realized price calculation for second quarter 2009.

Amounts received under the Bruce B floor price mechanism during the year are subject to repayment if the annual average spot price exceeds the annual average floor price. With respect to 2010, TransCanada currently expects average spot prices to be less than the floor price for the remainder of the year, therefore, no amounts recorded in revenue in the first six months of 2010 are expected to be repaid.

TransCanada's proportionate share of Bruce Power's Comparable EBITDA decreased \$91 million to \$110 million in the six months ended June 30, 2010 compared to the same period in 2009 as a result of lower volumes and higher operating costs due to higher planned and unplanned outage days at Bruce A, partially offset by the impact of a payment made in first quarter 2010 from Bruce B to Bruce A regarding 2009 amendments to the agreement with the OPA. The net positive impact to TransCanada in 2010 reflected TransCanada's higher percentage ownership in Bruce A.

Under a contract with the OPA, all of the output from Bruce A in second quarter 2010 was sold at a fixed price of \$64.71 per MWh (before recovery of fuel costs from the OPA) compared to \$64.45 per MWh in second quarter 2009. All output from the Bruce B units was subject to a floor price of \$48.96 per MWh in second quarter 2010 and \$48.76 per MWh in second quarter 2009. Both the Bruce A and Bruce B contract prices are adjusted annually for inflation on April 1.

Bruce B also enters into fixed-price contracts whereby Bruce B receives or pays the difference between the contract price and the spot price. Bruce B's realized price of \$59 per MWh in second quarter 2010 reflected revenues recognized from both the floor price mechanism and contract sales. A significant portion of these contracts will expire by the end of 2010, which is expected to result in lower realized prices at Bruce B for future periods. At June 30, 2010, Bruce B had sold forward approximately 1,000 GWh and 300 GWh, representing TransCanada's proportionate share, for the remainder of 2010 and 2011, respectively.

The overall plant availability percentage in 2010 is expected to be in the low 80s for the two operating Bruce A units and in the low 90s for the four Bruce B units. A planned outage of Bruce A Unit 3 began in late February 2010 and ended in late April 2010. A planned outage on Bruce B Unit 6 commenced mid-May 2010 with the unit returning to service late July 2010. A maintenance outage scheduled for mid-October 2010 for Bruce B Unit 5 has been reduced from ten weeks to three weeks.

As at June 30, 2010, Bruce A had incurred approximately \$3.6 billion in costs for the refurbishment and restart of Units 1 and 2, and approximately \$0.2 billion for the refurbishment of Units 3 and 4.

## U.S. Power

U.S. Power Comparable EBITDA<sup>(1)(2)</sup>

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Revenues				
Power <sup>(3)</sup>	244	202	485	457
Capacity	68	54	110	84
Other <sup>(3)(4)</sup>	16	11	42	57
	<b>328</b>	<b>267</b>	<b>637</b>	<b>598</b>
Commodity purchases resold <sup>(3)</sup>	(115)	(67)	(257)	(189)
Plant operating costs and other <sup>(4)</sup>	(132)	(124)	(224)	(291)
General, administrative and support costs	(9)	(11)	(18)	(23)
<b>Comparable EBITDA<sup>(1)</sup></b>	<b>72</b>	<b>65</b>	<b>138</b>	<b>95</b>

(1) Refer to the Non-GAAP Measures section of this MD&A for further discussion of Comparable EBITDA.

(2) Includes phase one of Kibby Wind effective October 2009.

(3) Effective January 1, 2010, the net impact of derivatives used to purchase and sell power, natural gas and fuel oil to manage U.S. Power's assets is presented on a net basis in Power Revenues. Comparative results for 2009 reflect amounts reclassified from Commodity Purchases Resold and Other Revenues to Power Revenues.

(4) Includes revenues and costs related to a third-party service agreement at Ravenswood.

U.S. Power Operating Statistics<sup>(1)</sup>

<i>(unaudited)</i>	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
<b>Sales Volumes (GWh)</b>				
Supply				
Generation	1,789	1,404	2,680	2,572
Purchased	2,061	1,135	4,547	2,394
	<b>3,850</b>	<b>2,539</b>	<b>7,227</b>	<b>4,966</b>
Sales				
Contracted	3,669	2,266	6,884	4,406
Spot	181	273	343	560
	<b>3,850</b>	<b>2,539</b>	<b>7,227</b>	<b>4,966</b>
<b>Plant Availability</b>	<b>92%</b>	<b>78%</b>	<b>89%</b>	<b>68%</b>

(1) Includes phase one of Kibby Wind effective October 2009.

U.S. Power's Comparable EBITDA for the three months ended June 30, 2010 was \$72 million, an increase of \$7 million compared to the same period in 2009. The increase was primarily due to higher volumes of power sold and increased capacity revenues, partially offset by the negative impact of a weaker U.S. dollar. For the six months ended June 30, 2010, U.S. Power's EBITDA of \$138 million increased \$43 million from the same period in 2009 primarily due to increased capacity revenues and a first quarter 2010 adjustment of Ravenswood's 2009 operating costs, partially offset by the negative impact of a weaker U.S. dollar.

U.S. Power's Power Revenues for the three and six months ended June 30, 2010 of \$244 million and \$485 million, respectively, increased from \$202 million and \$457 million in the same periods in 2009 primarily due to higher volumes of power sold, partially offset by the negative impact of a weaker U.S. dollar and lower realized power prices. Capacity Revenues increased for the three and six months ended June 30, 2010 to \$68 million and \$110 million, respectively, primarily due to higher capacity prices as a result of the long-planned retirement of a power generating facility owned by the New York Power Authority, which occurred at the end of January 2010, partially offset by the Unit 30 outage

from September 2008 to May 2009, which has a greater impact on 2010 capacity revenues due to the nature of the calculations.

Commodity Purchases Resold of \$115 million and \$257 million for the three and six months ended June 30, 2010, respectively, increased from \$67 million and \$189 million in the same periods in 2009 primarily due to an increase in the quantity of power purchased for resale under its power sales commitments in New England, partially offset by the positive impact of a weaker U.S. dollar, as well as lower contracted power prices per MWh for the six months ended June 30, 2010.

Plant Operating Costs and Other in the three months ended June 30, 2010 were \$132 million, an increase of \$8 million over the same period in 2009 primarily due to increased volumes, partially offset by the positive impact of a weaker U.S. dollar. In the six months ended June 30, 2010, Plant Operating Costs and Other were \$224 million, a decrease of \$67 million compared to the same period in 2009 primarily due to the positive impact of a weaker U.S. dollar and the cumulative impact of the Ravenswood prior year adjustment.

In both the three and six months ended June 30, 2010, 95 per cent of power sales volumes were sold under contract, compared to 89 per cent for the same periods in 2009. U.S. Power is focused on selling the majority of its power under contract to wholesale, commercial and industrial customers, while managing a portfolio of power supplies sourced from its own generation and wholesale power purchases. To reduce its exposure to spot market prices on uncontracted volumes, as at June 30, 2010, U.S. Power had entered into fixed-price power sales contracts to sell approximately 6,800 GWh for the remainder of 2010 and 8,600 GWh for 2011, including financial contracts to effectively lock in a margin on forecasted generation. Certain contracted volumes are dependent on customer usage levels and actual amounts contracted in future periods will depend on market liquidity and other factors.

Comparable EBITDA excluded net unrealized gains of \$9 million and net unrealized losses of \$19 million in the three and six months ended June 30, 2010, respectively, resulting from changes in the fair value of certain U.S. Power derivative contracts. Power is purchased under forward contracts to satisfy a significant portion of U.S. Power's wholesale, commercial and industrial power sales commitments, mitigating its exposure to fluctuations in spot market prices and effectively locking in a positive margin. In addition, power generation is managed by entering into contracts to sell a portion of power forecasted to be generated. Contracts are entered into simultaneously to purchase the fuel required to generate the power to reduce exposure to market price volatility and effectively lock in positive margins. Each of these contracts provide economic hedges which, in some cases, do not meet the specific criteria required for hedge accounting treatment and therefore are recorded at their fair value based on forward market prices. Effective January 1, 2010, the unrealized gains and losses from these contracts have been removed from Comparable EBITDA as they are not representative of amounts that will be realized on settlement of the contracts. Comparative amounts in 2009 were not material and therefore were not excluded from the computation of Comparable EBITDA.

#### *Natural Gas Storage*

Natural Gas Storage's Comparable EBITDA for the three and six month periods ended June 30, 2010, was \$18 million and \$69 million, respectively, compared to \$34 million and \$70 million for the same periods in 2009. The decrease in Comparable EBITDA in second quarter 2010 was primarily due to decreased proprietary and third party storage revenues as a result of lower realized natural gas price spreads. The seasonal nature of natural gas storage generally results in higher revenues in the winter season.

Comparable EBITDA excluded net unrealized gains of \$6 million and net unrealized losses of \$15 million in the three and six months ended June 30, 2010, respectively (2009 – losses of \$7 million and \$20 million), resulting from changes in the fair value of proprietary natural gas inventory in storage

and natural gas forward purchase and sale contracts. TransCanada manages its proprietary natural gas storage earnings by simultaneously entering into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to price movements of natural gas. Fair value adjustments recorded in each period on proprietary natural gas held in storage and these forward contracts are not representative of the amounts that will be realized on settlement. The fair value of proprietary natural gas inventory held in storage has been measured using a weighted average of forward prices for the following four months less selling costs.

## Other Income Statement Items

### Interest Expense

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Interest on long-term debt <sup>(1)</sup>	297	329	593	664
Other interest and amortization	33	(7)	53	7
Capitalized interest	(143)	(63)	(277)	(117)
	<b>187</b>	<b>259</b>	<b>369</b>	<b>554</b>

<sup>(1)</sup> Includes interest for Junior Subordinated Notes.

Interest Expense for second quarter 2010 decreased \$72 million to \$187 million from \$259 million in second quarter 2009. Interest Expense for the six months ended June 30, 2010 decreased \$185 million to \$369 million from \$554 million for the six months ended June 30, 2009. The decreases reflected increased capitalized interest to finance the Company's capital growth program in 2010, primarily due to Keystone construction, and the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest. These decreases were partially offset by incremental interest expense on new debt issues of US\$1.25 billion in June 2010 and \$700 million in February 2009, and by losses in 2010 compared to gains in 2009 from changes in the fair value of derivatives used to manage the Company's exposure to rising interest rates.

Interest Income and Other for second quarter 2010 was an expense of \$18 million compared to income of \$34 million for second quarter 2009. Interest Income and Other for the six months ended June 30, 2010 decreased \$50 million to \$6 million from \$56 million for the six months ended June 2009. Interest Income and Other was negatively impacted by losses in 2010 compared to gains in 2009 from derivatives used to manage the Company's exposure to foreign exchange fluctuations on U.S. dollar-denominated income and from the translation of working capital balances due to a strengthening U.S. dollar.

Income Taxes were \$65 million in second quarter 2010 compared to \$97 million for the same period in 2009. Income taxes for the six months ended June 30, 2010 were \$166 million compared to \$213 million for the same period in 2009. The decreases were primarily due to reduced pre-tax earnings and the net positive impact from income tax rate differentials and other income tax adjustments. In second quarter 2010, the Company recorded a benefit in Current Income Taxes and an offsetting provision in Future Income Taxes as a result of bonus depreciation for U.S. income tax purposes on Keystone assets placed into service June 30, 2010.

## Liquidity and Capital Resources

TransCanada's financial position remains sound and consistent with recent years as does its ability to generate cash in the short and long term to provide liquidity, maintain financial capacity and flexibility, and to provide for planned growth. TransCanada's liquidity position remains solid, underpinned by predictable cash flow from operations, significant cash balances on hand from recent



preferred share and debt issues, as well as committed revolving bank lines of US\$1.0 billion, \$2.0 billion, US\$1.0 billion and US\$300 million, maturing in November 2010, December 2012, December 2012 and February 2013, respectively. At June 30, 2010, draws of US\$300 million had been made on these facilities, which also support the Company's two commercial paper programs in Canada. In addition, TransCanada's proportionate share of capacity remaining available on committed bank facilities at TransCanada-operated affiliates was \$165 million with maturity dates from 2010 through 2012. As at June 30, 2010, TransCanada had remaining capacity of \$1.75 billion, \$2.0 billion and US\$2.75 billion under its equity, Canadian debt and U.S. debt shelf prospectuses, respectively. In lieu of making cash dividend payments, a portion of the declared common and preferred share dividends are expected to be paid in common shares issued under the Company's Dividend Reinvestment and Share Purchase Plan (DRP). TransCanada's liquidity, market and other risks are discussed further in the Risk Management and Financial Instruments section of this MD&A.

At June 30, 2010, the Company held Cash and Cash Equivalents of \$1.2 billion compared to \$1.0 billion at December 31, 2009. The increase in Cash and Cash Equivalents was primarily due to cash generated from operations, proceeds from the issuance of senior notes in second quarter 2010 and preferred shares in first and second quarter 2010, partially offset by capital expenditures.

### *Operating Activities*

#### **Funds Generated from Operations<sup>(1)</sup>**

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
<b>Cash Flows</b>				
Funds generated from operations <sup>(1)</sup>	935	692	1,658	1,458
(Increase)/decrease in operating working capital	(310)	246	(201)	328
Net cash provided by operations	625	938	1,457	1,786

<sup>(1)</sup> Refer to the Non-GAAP Measures section in this MD&A for further discussion of Funds Generated from Operations.

Net Cash Provided by Operations decreased \$313 million and \$329 million for the three and six months ended June 30, 2010, respectively, compared to the same periods in 2009, primarily due to increases in operating working capital. Funds Generated from Operations for the three and six months ended June 30, 2010 were \$935 million and \$1.7 billion, respectively, compared to \$692 million and \$1.5 billion for the same periods in 2009. The increases for the three and six months ended June 30, 2010 were primarily due to the income tax benefit generated from bonus depreciation for U.S. tax purposes on Keystone assets placed into service on June 30, 2010, partially offset by lower earnings.

### *Investing Activities*

TransCanada remains committed to executing its previously announced \$22 billion capital expenditure program. For the three and six months ended June 30, 2010, capital expenditures totalled \$1.0 billion and \$2.3 billion, respectively (2009 - \$1.3 billion and \$2.4 billion), primarily related to the construction of Keystone, expansion of the Alberta System, refurbishment and restart of Bruce A Units 1 and 2, and construction of the Guadalajara natural gas pipeline and Coolidge power plant.

### *Financing Activities*

In June 2010, TransCanada completed a public offering of 14 million Series 5 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares, under its September 2009 base shelf prospectus. The preferred shares were issued at a price of \$25 per share, resulting in gross proceeds of \$350 million including the underwriters' option. The holders of the Series 5 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of

\$1.10 per share, payable quarterly, yielding 4.4 per cent per annum for the initial five and a half year period ending January 30, 2016. The first dividend payment will be made on November 1, 2010. The dividend rate will reset on January 30, 2016 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 1.54 per cent. The Series 5 preferred shares are redeemable by TransCanada on January 30, 2016 and on January 30 of every fifth year thereafter. The net proceeds of this offering were used to partially fund capital projects, for other general corporate purposes and to repay short-term debt.

The Series 5 preferred shareholders will have the right to convert their shares into Series 6 cumulative redeemable first preferred shares on January 30, 2016 and on January 30 of every fifth year thereafter. The holders of Series 6 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 1.54 per cent.

In June 2010, TCPL issued senior notes of US\$500 million and US\$750 million maturing on June 1, 2015 and June 1, 2040, respectively, and bearing interest at 3.40 per cent and 6.10 per cent, respectively. These notes were issued under the US\$4.0 billion debt shelf prospectus filed in December 2009. The net proceeds of this offering were used to partially fund capital projects, for general corporate purposes and to repay short-term debt.

In March 2010, TransCanada completed a public offering of 14 million Series 3 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares, under its September 2009 base shelf prospectus. The preferred shares were issued at a price of \$25 per share, resulting in gross proceeds of \$350 million including the underwriters' option. The holders of the Series 3 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of \$1.00 per share, payable quarterly, yielding four per cent per annum for the initial five year period ending June 30, 2015. The first dividend payment was made on June 30, 2010. The dividend rate will reset on June 30, 2015 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 1.28 per cent. The Series 3 preferred shares are redeemable by TransCanada on June 30, 2015 and on June 30 of every fifth year thereafter. The net proceeds of this offering were used to partially fund capital projects, for general corporate purposes and to repay short-term debt.

The Series 3 preferred shareholders will have the right to convert their shares into Series 4 cumulative redeemable first preferred shares on June 30, 2015 and on June 30 of every fifth year thereafter. The holders of Series 4 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 1.28 per cent.

The Company is well positioned to fund its existing capital program through its growing internally-generated cash flow, its DRP and its continued access to capital markets. TransCanada will also continue to examine opportunities for portfolio management, including a role for PipeLines LP, in financing its capital program.

In the three and six months ended June 30, 2010, TransCanada issued \$1.3 billion (2009 – nil and \$3.1 billion), and retired \$142 million and \$283 million, respectively (2009 - \$18 million and \$500 million), of Long-Term Debt. Notes Payable decreased \$441 million and \$9 million in the three and six months ended June 30, 2010, respectively, compared to an increase of \$233 million and a decrease of \$684 million for the same periods in 2009.

### *Dividends*

On July 29, 2010, TransCanada's Board of Directors declared a quarterly dividend of \$0.40 per share for the quarter ending September 30, 2010 on the Company's outstanding common shares. It is

payable on October 29, 2010 to shareholders of record at the close of business on September 30, 2010. In addition, quarterly dividends of \$0.2875 and \$0.25 per preferred share were declared for Series 1 and Series 3 preferred shares, respectively, for the period ending September 30, 2010. The dividends are payable on September 30, 2010 to shareholders of record at the close of business on August 31, 2010. A dividend of \$0.3707 per preferred share was declared for Series 5 preferred shares for the period of June 29, 2010 to October 30, 2010. The dividend is payable on November 1, 2010 to shareholders of record at the close of business on September 30, 2010.

TransCanada's Board of Directors approved the issuance of common shares from treasury at a three per cent discount under TransCanada's DRP for dividends payable on TransCanada's common and preferred shares, and TCPL's preferred shares. The Company reserves the right to alter the discount or return to fulfilling DRP participation by purchasing shares on the open market at any time. In the three and six months ended June 30, 2010, TransCanada issued 2.6 million and 4.9 million (2009 – 1.4 million and 3.5 million) common shares, respectively, under its DRP, in lieu of making cash dividend payments of \$92 million and \$170 million, respectively (2009 - \$42 million and \$109 million).

### **Significant Accounting Policies and Critical Accounting Estimates**

To prepare financial statements that conform with Canadian GAAP, 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.

TransCanada's significant accounting policies and critical accounting estimates have remained unchanged since December 31, 2009. For further information on the Company's accounting policies and estimates refer to the MD&A in TransCanada's 2009 Annual Report.

### **Changes in Accounting Policies**

The Company's accounting policies have not changed materially from those described in TransCanada's 2009 Annual Report. Future accounting changes that will impact the Company are as follows:

#### *Future Accounting Changes*

### **International Financial Reporting Standards**

The Canadian Institute of Chartered Accountants' (CICA) Accounting Standards Board (AcSB) previously announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. As an SEC registrant, TransCanada has the option to prepare and file its consolidated financial statements using U.S. GAAP. Previously, TransCanada disclosed that effective January 1, 2011, the Company expected to begin reporting under IFRS. Prior to the developments noted below, the Company's IFRS conversion project was proceeding as planned to meet the January 1, 2011 conversion date.

#### *Rate-Regulated Accounting*

In accordance with Canadian GAAP, TransCanada currently follows specific accounting policies unique to a rate-regulated business which are consistent with rate-regulated accounting (RRA) standards in U.S. GAAP. Under RRA, the timing of recognition of certain expenses and revenues may differ from that otherwise expected under Canadian GAAP in order to appropriately reflect the economic impact of regulators' decisions regarding the Company's revenues and tolls. These timing

differences are recorded as regulatory assets and regulatory liabilities on TransCanada's consolidated balance sheet and represent current rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the applicable regulatory authorities. As at June 30, 2010, TransCanada reported \$1.7 billion of regulatory assets and \$0.4 billion of regulatory liabilities using RRA in addition to certain other impacts of RRA.

In July 2009, the IASB issued an Exposure Draft "Rate-Regulated Activities" which proposed a form of RRA under IFRS. To date, the IASB has not approved an RRA standard and TransCanada does not expect a final RRA standard under IFRS to be effective for 2011. As a result, in July 2010, the CICA's AcSB issued an Exposure Draft applicable to Canadian publicly accountable enterprises that use RRA which, if approved, would allow these entities to defer the adoption of IFRS for two years. A final decision is expected by the AcSB before the end of 2010. Due to the continued uncertainty around the timing, scope and eventual adoption of an RRA standard under IFRS, if the AcSB Exposure Draft is approved, TransCanada expects to defer its adoption of IFRS accordingly, and continue to prepare its consolidated financial statements in accordance with Canadian GAAP to maintain the use of RRA. During the deferral period, TransCanada will continue to actively monitor IASB developments with respect to RRA. If the AcSB Exposure Draft is not approved or the IASB has not approved an RRA standard within the two year deferral period that allows the Company's rate-regulated activities to be appropriately reflected in its consolidated financial statements, TransCanada expects to re-evaluate its decision to adopt IFRS and reconsider the adoption of U.S. GAAP.

As a result of these developments related to RRA under IFRS, TransCanada cannot reasonably quantify the full impact that adopting IFRS would have on its financial position and future results if it proceeded with adopting IFRS. The Company will continue to monitor non-RRA IFRS developments and their potential impact on TransCanada.

### **Contractual Obligations**

At June 30, 2010, TransCanada had entered into agreements totalling approximately \$530 million to purchase construction materials and services for the Bison natural gas pipeline and Cartier Wind power projects. Other than these commitments and expected increased payments for long-term debt resulting from new debt issuances as discussed in the Liquidity and Capital Resources section of this MD&A, there have been no material changes to TransCanada's contractual obligations from December 31, 2009 to June 30, 2010, including payments due for the next five years and thereafter. For further information on these contractual obligations, refer to the MD&A in TransCanada's 2009 Annual Report.

### **Financial Instruments and Risk Management**

TransCanada continues to manage and monitor its exposure to counterparty credit, liquidity and market risk.

#### *Counterparty Credit and Liquidity 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, the fair value of derivative assets and notes, loans and advances receivable. The carrying amounts and fair values of these financial assets are included in Accounts Receivable and Other in the Non-Derivative Financial Instruments Summary table below. Letters of credit and cash are the primary types of security provided to support these amounts. The majority of counterparty credit exposure is with counterparties who are investment grade. At June 30, 2010, there were no significant amounts past due or impaired.

At June 30, 2010, the Company had a credit risk concentration of \$348 million due from a creditworthy counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

The Company continues to manage its liquidity risk by ensuring sufficient cash and credit facilities are available to meet its operating and capital expenditure obligations when due, under both normal and stressed economic conditions.

#### *Natural Gas Inventory*

At June 30, 2010, the fair value of proprietary natural gas inventory held in storage, as measured using a weighted average of forward prices for the following four months less selling costs, was \$51 million (December 31, 2009 - \$73 million). The change in fair value of proprietary natural gas inventory in storage in the three and six months ended June 30, 2010 resulted in net pre-tax unrealized gains of \$4 million and net pre-tax unrealized losses of \$20 million, respectively, which were recorded as an increase and a decrease, respectively, to Revenues and Inventories (2009 - losses of \$6 million and \$29 million). The change in fair value of natural gas forward purchase and sale contracts in the three and six months ended June 30, 2010 resulted in net pre-tax unrealized gains of \$2 million and \$5 million, respectively (2009 - losses of \$1 million and gains of \$9 million), which were included in Revenues.

#### *VaR Analysis*

TransCanada uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its open liquid positions. VaR represents the potential change in pre-tax earnings over a given holding period. It is calculated assuming a 95 per cent confidence level that the daily change resulting from normal market fluctuations in its open positions will not exceed the reported VaR. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR. TransCanada's consolidated VaR was \$7 million at June 30, 2010 (December 31, 2009 - \$12 million). The decrease from December 31, 2009 was primarily due to decreased prices and lower open positions in the U.S. Power portfolio.

#### *Net Investment in Self-Sustaining Foreign Operations*

The Company hedges its net investment in self-sustaining 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. At June 30, 2010, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of \$9.4 billion (US\$8.8 billion) and a fair value of \$9.7 billion (US\$9.2 billion). At June 30, 2010, \$20 million (December 31, 2009 - \$96 million) was included in Intangibles and Other Assets for the fair value of forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

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

### Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

Asset/(Liability) ( <i>unaudited</i> ) ( <i>millions of dollars</i> )	June 30, 2010		December 31, 2009	
	Fair Value <sup>(1)</sup>	Notional or Principal Amount	Fair Value <sup>(1)</sup>	Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2010 to 2014)	37	U.S. 2,100	86	U.S. 1,850
U.S. dollar forward foreign exchange contracts (maturing 2010)	(17)	U.S. 550	9	U.S. 765
U.S. dollar foreign exchange options (matured 2010)	-	-	1	U.S. 100
	<b>20</b>	<b>U.S. 2,650</b>	<b>96</b>	<b>U.S. 2,715</b>

<sup>(1)</sup> Fair values equal carrying values.

### Non-Derivative Financial Instruments Summary

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

(unaudited) ( <i>millions of dollars</i> )	June 30, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
<b>Financial Assets<sup>(1)</sup></b>				
Cash and cash equivalents	1,211	1,211	997	997
Accounts receivable and other <sup>(2)(3)</sup>	1,342	1,383	1,432	1,483
Available-for-sale assets <sup>(2)</sup>	20	20	23	23
	<b>2,573</b>	<b>2,614</b>	<b>2,452</b>	<b>2,503</b>
<b>Financial Liabilities<sup>(1)(3)</sup></b>				
Notes payable	1,697	1,697	1,687	1,687
Accounts payable and deferred amounts <sup>(4)</sup>	1,287	1,287	1,538	1,538
Accrued interest	374	374	377	377
Long-term debt	17,845	21,125	16,664	19,377
Junior subordinated notes	1,050	1,072	1,036	976
Long-term debt of joint ventures	911	1,011	965	1,025
	<b>23,164</b>	<b>26,566</b>	<b>22,267</b>	<b>24,980</b>

<sup>(1)</sup> Consolidated Net Income in 2010 included gains of \$9 million (2009 – \$8 million) for fair value adjustments related to interest rate swap agreements on US\$150 million (2009 – US\$300 million) of long-term debt. There were no other unrealized gains or losses from fair value adjustments to the financial instruments.

<sup>(2)</sup> At June 30, 2010, the Consolidated Balance Sheet included financial assets of \$867 million (December 31, 2009 – \$966 million) in Accounts Receivable, \$42 million in Other Current Assets (December 31, 2009 – nil) and \$453 million (December 31, 2009 – \$489 million) in Intangibles and Other Assets.

<sup>(3)</sup> Recorded at amortized cost, except for certain long-term debt which is recorded at fair value.

<sup>(4)</sup> At June 30, 2010, the Consolidated Balance Sheet included financial liabilities of \$1,258 million (December 31, 2009 – \$1,513 million) in Accounts Payable and \$29 million (December 31, 2009 – \$25 million) in Deferred Amounts.

*Derivative Financial Instruments Summary*

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

**June 30, 2010***(unaudited)**(all amounts in millions unless otherwise indicated)*

	Power	Natural Gas	Foreign Exchange	Interest
<b>Derivative Financial Instruments</b>				
<b>Held for Trading<sup>(1)</sup></b>				
Fair Values <sup>(2)</sup>				
Assets	\$210	\$146	-	\$29
Liabilities	\$(158)	\$(145)	\$(20)	\$(90)
Notional Values				
Volumes <sup>(3)</sup>				
Purchases	13,165	117	-	-
Sales	14,285	89	-	-
Canadian dollars	-	-	-	960
U.S. dollars	-	-	U.S. 1,143	U.S. 1,525
Cross-currency	-	-	47/U.S. 37	-
Net unrealized (losses)/gains in the period <sup>(4)</sup>				
Three months ended June 30, 2010	\$(10)	\$3	\$(11)	\$(13)
Six months ended June 30, 2010	\$(26)	\$5	\$(11)	\$(17)
Net realized gains/(losses) in the period <sup>(4)</sup>				
Three months ended June 30, 2010	\$15	\$(17)	\$(6)	\$(6)
Six months ended June 30, 2010	\$37	\$(29)	\$2	\$(10)
Maturity dates	2010-2015	2010-2014	2010-2012	2010-2018
<b>Derivative Financial Instruments</b>				
<b>in Hedging Relationships<sup>(5)(6)</sup></b>				
Fair Values <sup>(2)</sup>				
Assets	\$124	\$1	-	\$9
Liabilities	\$(237)	\$(54)	\$(37)	\$(116)
Notional Values				
Volumes <sup>(3)</sup>				
Purchases	14,792	63	-	-
Sales	15,209	-	-	-
U.S. dollars	-	-	U.S. 120	U.S. 1,975
Cross-currency	-	-	136/U.S. 100	-
Net realized losses in the period <sup>(4)</sup>				
Three months ended June 30, 2010	\$(36)	\$(6)	-	\$(9)
Six months ended June 30, 2010	\$(43)	\$(9)	-	\$(19)
Maturity dates	2010-2015	2010-2012	2010-2014	2011-2020

(1) All derivative financial instruments in the held-for-trading classification 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 billion cubic feet (Bcf), respectively.

(4) Realized and unrealized gains and losses on power and natural gas derivative financial instruments held for trading are included 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 unrealized gains and

losses on derivative financial instruments in hedging relationships are initially recognized in Other Comprehensive Income and are 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 \$9 million and a notional amount of US\$150 million. Net realized gains on fair value hedges for the three and six months ended June 30, 2010 were \$1 million and \$2 million, respectively, and were included in Interest Expense. In second quarter 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.
- (6) Net Income for the three and six months ended June 30, 2010 included gains of \$7 million and losses of \$1 million, respectively, for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. There were no gains or losses included in Net Income for the three and six months ended June 30, 2010 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

**2009***(unaudited)**(all amounts in millions unless otherwise indicated)*

	Power	Natural Gas	Oil Products	Foreign Exchange	Interest
<b>Derivative Financial Instruments Held for Trading</b>					
Fair Values <sup>(1)(2)</sup>					
Assets	\$150	\$107	\$5	-	\$25
Liabilities	\$(98)	\$(112)	\$(5)	\$(66)	\$(68)
Notional Values <sup>(2)</sup>					
Volumes <sup>(3)</sup>					
Purchases	15,275	238	180	-	-
Sales	13,185	194	180	-	-
Canadian dollars	-	-	-	-	574
U.S. dollars	-	-	-	U.S. 444	U.S. 1,325
Cross-currency	-	-	-	227/U.S. 157	-
Net unrealized (losses)/gains in the period <sup>(4)</sup>					
Three months ended June 30, 2009	\$(2)	\$10	\$(5)	\$1	\$27
Six months ended June 30, 2009	\$19	\$(25)	\$2	\$2	\$27
Net realized gains/(losses) in the period <sup>(4)</sup>					
Three months ended June 30, 2009	\$20	\$(39)	\$2	\$11	\$(5)
Six months ended June 30, 2009	\$30	\$(13)	\$(1)	\$17	\$(9)
Maturity dates <sup>(2)</sup>	2010-2015	2010-2014	2010	2010-2012	2010-2018
<b>Derivative Financial Instruments in Hedging Relationships<sup>(5)(6)</sup></b>					
Fair Values <sup>(1)(2)</sup>					
Assets	\$175	\$2	-	-	\$15
Liabilities	\$(148)	\$(22)	-	\$(43)	\$(50)
Notional Values <sup>(2)</sup>					
Volumes <sup>(3)</sup>					
Purchases	13,641	33	-	-	-
Sales	14,311	-	-	-	-
U.S. dollars	-	-	-	U.S. 120	U.S. 1,825
Cross-currency	-	-	-	136/U.S. 100	-
Net realized gains/(losses) in the period <sup>(4)</sup>					
Three months ended June 30, 2009	\$52	\$(10)	-	-	\$(10)
Six months ended June 30, 2009	\$78	\$(20)	-	-	\$(17)
Maturity dates <sup>(2)</sup>	2010-2015	2010-2014	n/a	2010-2014	2010-2020

(1) Fair values equal carrying values.

(2) As at December 31, 2009.

(3) Volumes for power, natural gas and oil products derivatives are in GWh, Bcf and thousands of barrels, respectively.

(4) Realized and unrealized gains and losses on power, natural gas and oil products derivative financial instruments held for trading are



included 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 unrealized gains and losses on derivative financial instruments in hedging relationships are initially recognized in Other Comprehensive Income, and are 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 \$4 million and a notional amount of US\$150 million at December 31, 2009. Net realized gains on fair value hedges for the three and six months ended June 30, 2009 were \$1 million and \$2 million, respectively, and were included in Interest Expense. In second quarter 2009, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.
- (6) Net Income for the three and six months ended June 30, 2009 included losses of \$4 million and gains of \$1 million, respectively, for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. There were no gains or losses included in Net Income for the three and six months ended June 30, 2009 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

### *Balance Sheet Presentation of Derivative Financial Instruments*

The fair value of the derivative financial instruments in the Company's Balance Sheet was as follows:

<i>(unaudited)</i> <i>(millions of dollars)</i>	June 30, 2010	December 31, 2009
<b>Current</b>		
Other current assets	311	315
Accounts payable	(406)	(340)
<b>Long-term</b>		
Intangibles and other assets	228	260
Deferred amounts	(451)	(272)

### **Controls and Procedures**

As of June 30, 2010, an evaluation was carried out under the supervision of, and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of TransCanada's disclosure controls and procedures as defined under the rules adopted by the Canadian securities regulatory authorities and by the SEC. Based on this evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the design and operation of TransCanada's disclosure controls and procedures were effective as at June 30, 2010.

During the recent fiscal quarter, there have been no changes in TransCanada's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, TransCanada's internal control over financial reporting.

### **Outlook**

Since the disclosure in TransCanada's 2009 Annual Report, the Company's earnings outlook for 2010 is relatively unchanged as the Company expects reduced EBITDA from Keystone to be offset by higher capitalized interest. Although the Company's expectation for market power prices has improved in second quarter 2010, Energy's EBIT is still subject to volatility in market power prices. For further information on outlook, refer to the MD&A in TransCanada's 2009 Annual Report.

## **Recent Developments**

### **Pipelines**

#### *Keystone*

In June 2010, line fill on the first phase of the Keystone oil pipeline was completed and on June 30, 2010, the pipeline was placed into commercial service. The first phase of Keystone extends from Hardisty, Alberta to serve markets in Wood River and Patoka, Illinois and has an initial nominal capacity of 435,000 barrels per day (Bbl/d). As part of the NEB's approval to begin operations, Keystone will operate at a reduced maximum operating pressure (MOP), which will reduce throughput capacity below initial nominal capacity. As required by the NEB, additional in-line inspections on the Canadian segment of the pipeline have been completed. Analysis of the data from these inspections, any remedial work if necessary, and removal of the MOP restriction are expected to be completed in fourth quarter 2010.

Construction of the second phase of Keystone to expand nominal capacity to 591,000 Bbl/d and extend the pipeline to Cushing, Oklahoma began in second quarter 2010. Commercial in service of the second phase is expected to occur in first quarter 2011.

Keystone is planning to construct and operate an expansion and extension of the pipeline system that will provide additional capacity of 500,000 Bbl/d from Western Canada to the U.S. Gulf Coast in first quarter 2013. The Keystone expansion will extend from Hardisty to a delivery point near existing terminals in Port Arthur, Texas. In March 2010, the NEB approved the Company's application to construct and operate the Canadian portion of the Keystone expansion. In April 2010, the U.S. Department of State, the lead agency for federal regulatory approvals, issued a Draft Environmental Impact Statement which concluded that Keystone's expansion to the Gulf Coast would have limited environmental impact. In June 2010, the Department of State solicited the views of specifically identified federal departments and agencies, including the Department of Energy and the Environmental Protection Agency, on whether granting the approvals for Keystone would be in the national interest, requesting a response by September 2010. After consultation with those agencies, the Department of State has decided to provide those agencies with the full benefit of the final Environmental Impact Statement before starting the 90 day period within which those agencies provide their comments to the Department of State. Assuming regulatory approval is granted in first quarter 2011, construction is expected to begin shortly thereafter.

In response to significant market demand, the Company is pursuing opportunities to attract growing Bakken shale crude oil production from the Williston Basin in Montana and North Dakota to Keystone for delivery to major U.S. refining markets. Commercial definition and project scoping are underway and the Company expects to launch an open season in third quarter 2010. Commercial in service is anticipated in first quarter 2013, subject to the results of the open season.

The total capital cost of Keystone is expected to be approximately US\$12 billion. Approximately US\$6 billion has been spent to date, including approximately US\$800 million for the expansion to the Gulf Coast, with the remaining US\$6 billion to be invested between now and the end of 2012. Capital costs related to the construction of Keystone are subject to capital cost risk- and reward-sharing mechanisms with its customers.

Although the first phase of Keystone is now in commercial service, all cash flow related to Keystone is expected to be capitalized until the MOP restriction has been removed. TransCanada expects Keystone to begin recording EBITDA in fourth quarter 2010 when the MOP restriction on the Canadian segment is expected to be removed, with EBITDA increasing through 2011, 2012 and 2013 as subsequent phases are placed in service. Based on current long-term commitments of 910,000 Bbl/d,

Keystone is expected to generate EBITDA of approximately US\$1.2 billion in 2013, its first full year of commercial operation serving both the U.S. Midwest and Gulf Coast markets. If volumes increase to 1.1 million Bbl/d, the full commercial design of the system, Keystone would generate approximately US\$1.5 billion of annual EBITDA. In the future, Keystone can be economically expanded from 1.1 million Bbl/d to 1.5 million Bbl/d in response to additional market demand.

Three entities, each of which had entered into Transportation Service Agreements for the second phase of the Keystone pipeline, have filed separate Statements of Claim against certain of TransCanada's Keystone subsidiaries in the Alberta Court of Queen's Bench, seeking declaratory relief or alternatively, damages in varying amounts. Only one of these Statements of Claim has been served on the Keystone subsidiaries. The Company believes each of the claims to be without merit and will vigorously defend these actions.

### *Canadian Mainline*

Tolls on the Canadian Mainline in any year are based, in part, on projected throughput volumes for the year. Estimated throughput volumes for 2010 are now expected to be lower than was used in setting tolls for 2010. As a result, revenues are projected to be ten per cent to 15 per cent less than anticipated. This revenue shortfall is expected to be collected in future tolls.

TransCanada has developed a comprehensive proposal concerning rate design, services and business model that responds to changing market dynamics. This proposal was conveyed to customers at the end of first quarter 2010 and discussions with customers are continuing. A related NEB filing is anticipated before year end.

With the objective of maintaining markets and competitive position, TransCanada has signed precedent agreements for 100,000 gigajoules per day for ten years to move Marcellus shale natural gas from Niagara, Ontario to Eastern Canadian markets. In response to continuing customer interest, TransCanada has initiated a further open season for new capacity for service from Niagara and Chippawa, Ontario.

### *Alberta System*

In June 2010, TransCanada reached a three year settlement agreement with Alberta System shippers and other interested parties and filed a 2010 – 2012 Revenue Requirement Settlement Application with the NEB. The settlement provides for a cost of capital reflecting a 9.70 per cent ROE on deemed common equity of 40 per cent and includes a fixed amount for certain OM&A costs. Variances between actual and agreed to OM&A costs will accrue to TransCanada. All other cost elements of the revenue requirement will be treated on a flow-through basis. TransCanada expects to receive regulatory approval from the NEB of the settlement in third quarter 2010.

TransCanada anticipates filing for final rates in 2010 pending NEB approval of the 2010 – 2012 Revenue Requirement Settlement Application and the application for the Alberta System rate design and commercial and operational integration of the Canadian Utilities Limited (ATCO Pipelines) system.

Construction of the Groundbirch pipeline is expected to begin in August 2010 and is estimated to be in service by November 2010. When completed, the project will consist of a natural gas pipeline that will extend the Alberta System, connecting to natural gas supplies in the Montney shale gas formation in northeast B.C. The approximate \$200 million project has firm transportation contracts that will reach 1.1 billion cubic feet per day by 2014.

TransCanada continues to advance the Horn River natural gas pipeline project which will bring northeast B.C. shale gas to market through the Alberta System. Subject to regulatory approvals, the

approximate \$310 million Horn River project is expected to be operational in second quarter 2012 with commitments for contracted natural gas rising to approximately 540 million cubic feet per day by 2014.

TransCanada continues to receive additional requests for firm transportation service on both the Horn River and Groundbirch pipeline projects.

### *Foothills*

In June 2010, TransCanada reached an agreement to establish a cost of capital for Foothills which reflects a 9.70 per cent ROE on deemed common equity of 40 per cent for the years 2010 to 2012. Final tolls for 2010 have been approved by the NEB, effective July 1, 2010.

### *TQM*

In June 2010, the NEB approved the final 2009 tolls for TQM as submitted which reflect a 6.4 per cent after-tax weighted average cost of capital return on rate base.

### *Alaska*

The open season for the Alaska Pipeline Project will conclude on July 30, 2010. Throughout the 90 day open season, potential shippers have assessed the merits of the open season and the Alaska Pipeline Project has provided information to potential shippers in Alaska and Canada about the project's anticipated engineering design, commercial terms, estimated project costs and timelines.

Interested shippers will submit commercial bids prior to the close of the open season. It is typical with large, complex pipeline projects for bids from shippers to be conditional. The Alaska Pipeline Project will work with shippers to resolve any of these conditions within the project's control. Other key issues such as Alaska fiscal terms and natural gas resource access at Point Thomson, Alaska will need to be resolved between shippers and the State of Alaska. The Alaska Pipeline Project is expecting to complete these discussions and announce the results of the open season by the end of 2010.

### *Bison*

In July 2010, TransCanada received final approval to commence construction on a majority of the Bison natural gas pipeline project. Approvals for the remainder of the pipeline are expected in third quarter 2010. The Company commenced construction in July 2010 on the approximate US\$600 million project which has an anticipated in-service date of fourth quarter 2010.

### *Great Lakes*

On July 15, 2010, the Federal Energy Regulatory Commission (FERC) approved without modification the settlement stipulation and agreement reached among Great Lakes, active participants and the FERC trial staff. As approved, the stipulation and agreement will apply to all current and future shippers on Great Lakes' system. The Company does not expect the settlement to have a material effect on the results for Great Lakes given the current market environment.

## **Energy**

### *Halton Hills*

The \$700 million Halton Hills generating station is in the final stages of commissioning and is expected to be in service in third quarter 2010, on time and on budget. Power from the 683 MW natural gas-

fired power plant near Halton Hills, Ontario will be sold to the OPA under a 20 year Clean Energy Supply contract.

#### *Bécancour*

In June 2010, Hydro-Québec notified TransCanada it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant throughout 2011. Under the original agreement signed in June 2009, Hydro-Québec has the option, subject to certain conditions, to extend the suspension on an annual basis until such time as regional electricity demand levels recover. TransCanada will continue to receive payments under the agreement similar to those that would have been received under the normal course of operation.

#### *Ravenswood*

In September 2008, TransCanada experienced a forced outage event related to the 972 MW Unit 30 at Ravenswood. The insurers of the business interruption and physical damage claim have denied coverage based on current claim information submitted for this event, however, they have invited TransCanada to enter into settlement discussions. TransCanada has filed a claim against the insurers to enforce its rights under the insurance policies. No amounts have been accrued for claims with respect to business interruption losses.

#### *Sundance B*

In second quarter 2010, Sundance B Unit 3 experienced an unplanned outage that the facility operator has asserted is a force majeure event. No information has been provided by the operator to date that supports the operator's claim that a force majeure event has occurred. Therefore, TransCanada has recorded revenues under the PPA as though this event was a normal plant outage.

#### *Oakville*

TransCanada continues to work through permitting issues with the Town of Oakville and the Province of Ontario on the 900 MW Oakville power generating station. A final Environmental Review Report is expected to be submitted to the Ontario Ministry of Environment in August 2010. As at June 30, 2010, TransCanada had capitalized \$62 million of costs related to the project.

#### *Kibby Wind*

Construction continues on the 66 MW second phase of the Kibby Wind project, which includes the installation of an additional 22 turbines. As at June 30, 2010, 12 of the wind turbine generators had been erected, ahead of schedule. The second phase is expected to be in service in fourth quarter 2010.

#### *Power Transmission Line Projects*

In May 2010, TransCanada announced that it had concluded a successful open season for the proposed Zephyr power transmission (Zephyr) project and had received signed agreements for the full 3,000 megawatts (MW) of wind-generated capacity with renewable energy developers in Wyoming. Support from key markets and a positive regulatory environment are necessary before the significant siting and permitting activities required to construct the project will commence. The 1,600 kilometre (1,000 mile), 500 kilovolt, high voltage direct current line (HVDC) Zephyr project is expected to cost approximately US\$3 billion and commercial operations are expected to commence in late 2015 or early 2016.

TransCanada continues to pursue the proposed Chinook power transmission project, a 500 kilovolt, HVDC transmission line originating in Montana, and has extended its open season to December 16, 2010.

## Share Information

As at July 27, 2010, TransCanada had 690 million issued and outstanding common shares, and nine million outstanding options to purchase common shares, of which six million were exercisable. As at July 27, 2010, TransCanada had the following preferred shares issuable or issued and outstanding:

<i>(unaudited)</i>	Issued and Outstanding	Issuable Upon Conversion
Series 1	22 million	-
Series 2 <sup>(1)</sup>	-	22 million
Series 3	14 million	-
Series 4 <sup>(1)</sup>	-	14 million
Series 5	14 million	-
Series 6 <sup>(1)</sup>	-	14 million

<sup>(1)</sup> Series 2, 4 and 6 preferred shares are issuable upon conversion of Series 1, 3, and 5 preferred shares, respectively.

## Selected Quarterly Consolidated Financial Data<sup>(1)</sup>

<i>(unaudited)</i> <i>(millions of dollars except per share amounts)</i>	2010		2009				2008	
	Second	First	Fourth	Third	Second	First	Fourth	Third
Revenues	1,923	1,955	1,986	2,049	1,984	2,162	2,234	2,145
Net Income	295	303	387	345	314	334	277	390
<b>Share Statistics</b>								
Net income per share – Basic	<b>\$0.41</b>	<b>\$0.43</b>	\$0.56	\$0.50	\$0.50	\$0.54	\$0.47	\$0.67
Net income per share – Diluted	<b>\$0.41</b>	<b>\$0.43</b>	\$0.56	\$0.50	\$0.50	\$0.54	\$0.46	\$0.67
Dividend declared per common share	<b>\$0.40</b>	<b>\$0.40</b>	\$0.38	\$0.38	\$0.38	\$0.38	\$0.36	\$0.36

<sup>(1)</sup> The selected quarterly consolidated financial data has been prepared in accordance with Canadian GAAP. Certain comparative figures have been restated to conform with the current year's presentation.

### *Factors Impacting Quarterly Financial Information*

In Pipelines, which consists primarily of the Company's investments in regulated pipelines and regulated natural gas storage facilities, annual revenues and net income fluctuate over the long term based on regulators' decisions and negotiated settlements with shippers. Generally, quarter-over-quarter revenues and net income during any particular fiscal year remain relatively stable with fluctuations resulting from adjustments being recorded due to regulatory decisions and negotiated settlements with shippers, seasonal fluctuations in short-term throughput volumes on U.S. pipelines, acquisitions and divestitures, and developments outside of the normal course of operations.

In Energy, which consists primarily of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities, quarter-over-quarter revenues and net income are affected by seasonal weather conditions, customer demand, market prices, capacity payments, planned and unplanned plant outages, acquisitions and divestitures, certain fair value adjustments and developments outside of the normal course of operations.

Significant developments that impacted the last eight quarters' EBIT and Net Income are as follows:

- Second quarter 2010, Energy's EBIT included net unrealized gains of \$9 million pre-tax (\$6 million after tax) resulting from changes in the fair value of certain U.S. Power derivative contracts. Energy's EBIT also included net unrealized gains of \$6 million pre-tax (\$4 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Net Income included \$58 million of losses in 2010 compared to gains in 2009 for interest rate and foreign exchange rate derivatives that did not qualify as hedges for accounting purposes and the translation of working capital balances.
- First quarter 2010, Energy's EBIT included net unrealized losses of \$28 million pre-tax (\$17 million after tax) resulting from changes in the fair value of certain U.S. Power derivative contracts. Energy's EBIT also included net unrealized losses of \$21 million pre-tax (\$15 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.
- Fourth quarter 2009, Pipelines' EBIT included a dilution gain of \$29 million pre-tax (\$18 million after tax) resulting from TransCanada's reduced ownership interest in PipeLines LP after PipeLines LP issued common units to the public. Energy's EBIT included net unrealized gains of \$7 million pre-tax (\$5 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Net Income included \$30 million of favourable income tax adjustments resulting from reductions in the Province of Ontario's corporate income tax rates.
- Third quarter 2009, Energy's EBIT included net unrealized gains of \$14 million pre-tax (\$10 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.
- Second quarter 2009, Energy's EBIT included net unrealized losses of \$7 million pre-tax (\$5 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Energy's EBIT also included contributions from Portlands Energy, which was placed in service in April 2009, and the negative impact of Western Power's lower overall realized power prices.
- First quarter 2009, Energy's EBIT included net unrealized losses of \$13 million pre-tax (\$9 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.
- Fourth quarter 2008, Energy's EBIT included net unrealized gains of \$7 million pre-tax (\$6 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Net Income included net unrealized losses of \$57 million pre-tax (\$39 million after tax) due to changes in the fair value of derivatives used to manage the Company's exposure to rising interest rates but which did not qualify as hedges for accounting purposes.
- Third quarter 2008, Energy's EBIT included contributions from the August 2008 acquisition of Ravenswood. Net Income included favourable income tax adjustments of \$26 million from an internal restructuring and realization of losses.

## Consolidated Income

<i>(unaudited)</i> <i>(millions of dollars except per share amounts)</i>	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
<b>Revenues</b>	<b>1,923</b>	<b>1,984</b>	<b>3,878</b>	<b>4,146</b>
<b>Operating and Other Expenses</b>				
Plant operating costs and other	764	792	1,511	1,607
Commodity purchases resold	216	182	472	411
Depreciation and amortization	341	345	684	691
	<b>1,321</b>	<b>1,319</b>	<b>2,667</b>	<b>2,709</b>
<b>Financial Charges/(Income)</b>				
Interest expense	187	259	369	554
Interest expense of joint ventures	15	16	31	30
Interest income and other	18	(34)	(6)	(56)
	<b>220</b>	<b>241</b>	<b>394</b>	<b>528</b>
<b>Income before Income Taxes and Non-Controlling Interests</b>	<b>382</b>	<b>424</b>	<b>817</b>	<b>909</b>
<b>Income Taxes</b>				
Current	(199)	35	(118)	89
Future	264	62	284	124
	<b>65</b>	<b>97</b>	<b>166</b>	<b>213</b>
<b>Non-Controlling Interests</b>				
Non-controlling interest in PipeLines LP	17	8	39	32
Preferred share dividends of subsidiary	5	5	11	11
Non-controlling interest in Portland	-	-	3	5
	<b>22</b>	<b>13</b>	<b>53</b>	<b>48</b>
<b>Net Income</b>	<b>295</b>	<b>314</b>	<b>598</b>	<b>648</b>
<b>Preferred Share Dividends</b>	<b>10</b>	<b>-</b>	<b>17</b>	<b>-</b>
<b>Net Income Applicable to Common Shares</b>	<b>285</b>	<b>314</b>	<b>581</b>	<b>648</b>
<b>Net Income Per Share - Basic and Diluted</b>	<b>\$0.41</b>	<b>\$0.50</b>	<b>\$0.84</b>	<b>\$1.04</b>
<b>Average Shares Outstanding – Basic (millions)</b>	<b>689</b>	<b>624</b>	<b>688</b>	<b>621</b>
<b>Average Shares Outstanding – Diluted (millions)</b>	<b>690</b>	<b>625</b>	<b>689</b>	<b>622</b>

See accompanying notes to the consolidated financial statements.



## Consolidated Cash Flows

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
<b>Cash Generated From Operations</b>				
Net income	295	314	598	648
Depreciation and amortization	341	345	684	691
Future income taxes	264	62	284	124
Non-controlling interests	22	13	53	48
Employee future benefits funding in excess of expense	(12)	(23)	(44)	(57)
Other	25	(19)	83	4
	<b>935</b>	<b>692</b>	<b>1,658</b>	<b>1,458</b>
(Increase)/decrease in operating working capital	(310)	246	(201)	328
Net cash provided by operations	<b>625</b>	<b>938</b>	<b>1,457</b>	<b>1,786</b>
<b>Investing Activities</b>				
Capital expenditures	(992)	(1,263)	(2,268)	(2,386)
Acquisitions, net of cash acquired	-	(115)	-	(249)
Deferred amounts and other	7	(99)	(209)	(274)
Net cash used in investing activities	<b>(985)</b>	<b>(1,477)</b>	<b>(2,477)</b>	<b>(2,909)</b>
<b>Financing Activities</b>				
Dividends on common and preferred shares	(195)	(193)	(383)	(349)
Distributions paid to non-controlling interests	(28)	(24)	(55)	(51)
Notes payable (repaid)/issued, net	(441)	233	(9)	(684)
Long-term debt issued, net of issue costs	1,306	-	1,316	3,060
Reduction of long-term debt	(142)	(18)	(283)	(500)
Long-term debt of joint ventures issued	70	92	78	108
Reduction of long-term debt of joint ventures	(113)	(33)	(139)	(56)
Common shares issued, net of issue costs	5	1,792	14	1,803
Preferred shares issued, net of issue costs	340	-	679	-
Net cash provided by financing activities	<b>802</b>	<b>1,849</b>	<b>1,218</b>	<b>3,331</b>
<b>Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents</b>	<b>33</b>	<b>(60)</b>	<b>16</b>	<b>(34)</b>
<b>Increase in Cash and Cash Equivalents</b>	<b>475</b>	<b>1,250</b>	<b>214</b>	<b>2,174</b>
<b>Cash and Cash Equivalents</b>				
Beginning of period	<b>736</b>	<b>2,232</b>	<b>997</b>	<b>1,308</b>
<b>Cash and Cash Equivalents</b>				
End of period	<b>1,211</b>	<b>3,482</b>	<b>1,211</b>	<b>3,482</b>
<b>Supplementary Cash Flow Information</b>				
Income taxes paid, net of refunds received	<b>39</b>	<b>56</b>	<b>43</b>	<b>113</b>
Interest paid, net of capitalized interest	<b>119</b>	<b>274</b>	<b>358</b>	<b>537</b>

See accompanying notes to the consolidated financial statements.

## Consolidated Balance Sheet

<i>(unaudited)</i> <i>(millions of dollars)</i>	June 30, 2010	December 31, 2009
<b>ASSETS</b>		
<b>Current Assets</b>		
Cash and cash equivalents	1,211	997
Accounts receivable	1,101	966
Inventories	454	511
Other	704	701
	<u>3,470</u>	<u>3,175</u>
<b>Plant, Property and Equipment</b>	<b>35,101</b>	<b>32,879</b>
<b>Goodwill</b>	<b>3,807</b>	<b>3,763</b>
<b>Regulatory Assets</b>	<b>1,483</b>	<b>1,524</b>
<b>Intangibles and Other Assets</b>	<b>2,167</b>	<b>2,500</b>
	<u>46,028</u>	<u>43,841</u>
<b>LIABILITIES AND SHAREHOLDERS' EQUITY</b>		
<b>Current Liabilities</b>		
Notes payable	1,697	1,687
Accounts payable	2,101	2,195
Accrued interest	374	377
Current portion of long-term debt	587	478
Current portion of long-term debt of joint ventures	116	212
	<u>4,875</u>	<u>4,949</u>
<b>Regulatory Liabilities</b>	<b>313</b>	<b>385</b>
<b>Deferred Amounts</b>	<b>947</b>	<b>743</b>
<b>Future Income Taxes</b>	<b>3,008</b>	<b>2,856</b>
<b>Long-Term Debt</b>	<b>17,258</b>	<b>16,186</b>
<b>Long-Term Debt of Joint Ventures</b>	<b>795</b>	<b>753</b>
<b>Junior Subordinated Notes</b>	<b>1,050</b>	<b>1,036</b>
	<u>28,246</u>	<u>26,908</u>
<b>Non-Controlling Interests</b>		
Non-controlling interest in PipeLines LP	714	705
Preferred shares of subsidiary	389	389
Non-controlling interest in Portland	83	80
	<u>1,186</u>	<u>1,174</u>
<b>Shareholders' Equity</b>	<b>16,596</b>	<b>15,759</b>
	<u>46,028</u>	<u>43,841</u>

See accompanying notes to the consolidated financial statements.

### Consolidated Comprehensive Income

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
<b>Net Income Applicable to Common Shares</b>	<b>285</b>	<b>314</b>	<b>581</b>	<b>648</b>
<b>Other Comprehensive Income/(Loss), Net of Income Taxes</b>				
Change in foreign currency translation gains and losses on investments in foreign operations <sup>(1)</sup>	<b>227</b>	(113)	<b>80</b>	(151)
Change in gains and losses on hedges of investments in foreign operations <sup>(2)</sup>	<b>(79)</b>	96	<b>(20)</b>	96
Change in gains and losses on derivative instruments designated as cash flow hedges <sup>(3)</sup>	<b>(44)</b>	37	<b>(121)</b>	64
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods <sup>(4)</sup>	<b>(3)</b>	(9)	<b>(2)</b>	(5)
Other Comprehensive Income/(Loss)	<b>101</b>	11	<b>(63)</b>	4
<b>Comprehensive Income</b>	<b>386</b>	<b>325</b>	<b>518</b>	<b>652</b>

<sup>(1)</sup> Net of income tax recovery of \$45 million and \$15 million for the three and six months ended June 30, 2010, respectively (2009 – expense of \$6 million and nil, respectively).

<sup>(2)</sup> Net of income tax recovery of \$34 million and \$8 million for the three and six months ended June 30, 2010, respectively (2009 – expense of \$48 million and \$52 million, respectively).

<sup>(3)</sup> Net of income tax recovery of \$27 million and \$84 million for the three and six months ended June 30, 2010, respectively (2009 – expense of \$19 million and \$16 million, respectively).

<sup>(4)</sup> Net of income tax expense of \$16 million and \$17 million for the three and six months ended June 30, 2010, respectively (2009 – recovery of \$1 million and nil, respectively).

See accompanying notes to the consolidated financial statements.

### Consolidated Accumulated Other Comprehensive (Loss)/Income

<i>(unaudited)</i> <i>(millions of dollars)</i>	Currency Translation Adjustments	Cash Flow Hedges	Total
Balance at December 31, 2009	(592)	(40)	(632)
Change in foreign currency translation gains and losses on investments in foreign operations <sup>(1)</sup>	80	-	80
Change in gains and losses on hedges of investments in foreign operations <sup>(2)</sup>	(20)	-	(20)
Change in gains and losses on derivative instruments designated as cash flow hedges <sup>(3)</sup>	-	(121)	(121)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods <sup>(4)(5)</sup>	-	(2)	(2)
Balance at June 30, 2010	<u>(532)</u>	<u>(163)</u>	<u>(695)</u>
Balance at December 31, 2008	(379)	(93)	(472)
Change in foreign currency translation gains and losses on investments in foreign operations <sup>(1)</sup>	(151)	-	(151)
Change in gains and losses on hedges of investments in foreign operations <sup>(2)</sup>	96	-	96
Changes in gains and losses on derivative instruments designated as cash flow hedges <sup>(3)</sup>	-	64	64
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods <sup>(4)</sup>	-	(5)	(5)
Balance at June 30, 2009	<u>(434)</u>	<u>(34)</u>	<u>(468)</u>

<sup>(1)</sup> Net of income tax recovery of \$15 million for the six months ended June 30, 2010 (2009 - nil).

<sup>(2)</sup> Net of income tax recovery of \$8 million for the six months ended June 30, 2010 (2009 - \$52 million expense).

<sup>(3)</sup> Net of income tax recovery of \$84 million for the six months ended June 30, 2010 (2009 - \$16 million expense).

<sup>(4)</sup> Net of income tax expense of \$17 million for the six months ended June 30, 2010 (2009 - nil).

<sup>(5)</sup> Losses related to cash flow hedges reported in Accumulated Other Comprehensive (Loss)/Income and expected to be reclassified to Net Income in the next 12 months are estimated to be \$74 million (\$45 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.

See accompanying notes to the consolidated financial statements.

### Consolidated Shareholders' Equity

*(unaudited)*

*(millions of dollars)*

Six months ended June 30  
2010                      2009

**Common Shares**

Balance at beginning of period	11,338	9,264
Shares issued under dividend reinvestment plan	170	109
Proceeds from shares issued on exercise of stock options	14	11
Proceeds from shares issued under public offering, net of issue costs	-	1,792
Balance at end of period	<u>11,522</u>	<u>11,176</u>

**Preferred Shares**

Balance at beginning of period	539	-
Proceeds from shares issued under public offering, net of issue costs	685	-
Balance at end of period	<u>1,224</u>	<u>-</u>

**Contributed Surplus**

Balance at beginning of period	328	279
Issuance of stock options	2	1
Balance at end of period	<u>330</u>	<u>280</u>

**Retained Earnings**

Balance at beginning of period	4,186	3,827
Net income	598	648
Common share dividends	(552)	(494)
Preferred share dividends	(17)	-
Balance at end of period	<u>4,215</u>	<u>3,981</u>

**Accumulated Other Comprehensive (Loss)/Income**

Balance at beginning of period	(632)	(472)
Other comprehensive (loss)/income	(63)	4
Balance at end of period	<u>(695)</u>	<u>(468)</u>
	<u>3,520</u>	<u>3,513</u>

**Total Shareholders' Equity**

<b>16,596</b>	<b>14,969</b>
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See accompanying notes to the consolidated financial statements.

## Notes to Consolidated Financial Statements

(Unaudited)

### 1. Significant Accounting Policies

The consolidated financial statements of TransCanada Corporation (TransCanada or the Company) have been prepared in accordance with Canadian generally accepted accounting principles (GAAP). The accounting policies applied are consistent with those outlined in TransCanada's annual audited Consolidated Financial Statements for the year ended December 31, 2009. These Consolidated Financial Statements reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective periods. These Consolidated Financial Statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2009 audited Consolidated Financial Statements included in TransCanada's 2009 Annual Report. Unless otherwise indicated, "TransCanada" or "the Company" includes TransCanada Corporation and its subsidiaries. Amounts are stated in Canadian dollars unless otherwise indicated. Certain comparative figures have been reclassified to conform with the current year's presentation.

In Pipelines, which consists primarily of the Company's investments in regulated pipelines and regulated natural gas storage facilities, annual revenues and net income fluctuate over the long term based on regulators' decisions and negotiated settlements with shippers. Generally, quarter-over-quarter revenues and net income during any particular fiscal year remain relatively stable with fluctuations resulting from adjustments being recorded due to regulatory decisions and negotiated settlements with shippers, seasonal fluctuations in short-term throughput volumes on U.S. pipelines, acquisitions and divestitures, and developments outside of the normal course of operations.

In Energy, which consists primarily of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities, quarter-over-quarter revenues and net income are affected by seasonal weather conditions, customer demand, market prices, capacity payments, planned and unplanned plant outages, acquisitions and divestitures, certain fair value adjustments and developments outside of the normal course of operations.

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 consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies.

## 2. Changes in Accounting Policies

The Company's accounting policies have not changed materially from those described in TransCanada's 2009 Annual Report. Future accounting changes that will impact the Company are as follows:

### *Future Accounting Changes*

#### **International Financial Reporting Standards**

The Canadian Institute of Chartered Accountants' (CICA) Accounting Standards Board (AcSB) previously announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. As an SEC registrant, TransCanada has the option to prepare and file its consolidated financial statements using U.S. GAAP. Previously, TransCanada disclosed that effective January 1, 2011, the Company expected to begin reporting under IFRS. Prior to the developments noted below, the Company's IFRS conversion project was proceeding as planned to meet the January 1, 2011 conversion date.

#### *Rate-Regulated Accounting*

In accordance with Canadian GAAP, TransCanada currently follows specific accounting policies unique to a rate-regulated business which are consistent with rate-regulated accounting (RRA) standards in U.S. GAAP. Under RRA, the timing of recognition of certain expenses and revenues may differ from that otherwise expected under Canadian GAAP in order to appropriately reflect the economic impact of regulators' decisions regarding the Company's revenues and tolls. These timing differences are recorded as regulatory assets and regulatory liabilities on TransCanada's consolidated balance sheet and represent current rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the applicable regulatory authorities. As at June 30, 2010, TransCanada reported \$1.7 billion of regulatory assets and \$0.4 billion of regulatory liabilities using RRA in addition to certain other impacts of RRA.

In July 2009, the IASB issued an Exposure Draft "Rate-Regulated Activities" which proposed a form of RRA under IFRS. To date, the IASB has not approved an RRA standard and TransCanada does not expect a final RRA standard under IFRS to be effective for 2011. As a result, in July 2010, the CICA's AcSB issued an Exposure Draft applicable to Canadian publicly accountable enterprises that use RRA which, if approved, would allow these entities to defer the adoption of IFRS for two years. A final decision is expected by the AcSB before the end of 2010. Due to the continued uncertainty around the timing, scope and eventual adoption of an RRA standard under IFRS, if the AcSB Exposure Draft is approved, TransCanada expects to defer its adoption of IFRS accordingly, and continue to prepare its consolidated financial statements in accordance with Canadian GAAP to maintain the use of RRA. During the deferral period, TransCanada will continue to actively monitor IASB developments with respect to RRA. If the AcSB Exposure Draft is not approved or the IASB has not approved an RRA standard within the two year deferral period that allows the Company's rate-regulated activities to be appropriately reflected in its consolidated financial statements, TransCanada expects to re-evaluate its decision to adopt IFRS and reconsider the adoption of U.S. GAAP.

As a result of these developments related to RRA under IFRS, TransCanada cannot reasonably quantify the full impact that adopting IFRS would have on its financial position and future results if it proceeded with adopting IFRS. The Company will continue to monitor non-RRA IFRS developments and their potential impact on TransCanada.

### 3. Segmented Information

Three months ended June 30 <i>(unaudited)(millions of dollars)</i>	Pipelines		Energy <sup>(1)</sup>		Corporate		Total	
	2010	2009	2010	2009	2010	2009	2010	2009
Revenues	1,061	1,142	862	842	-	-	1,923	1,984
Plant operating costs and other	(365)	(395)	(377)	(366)	(22)	(31)	(764)	(792)
Commodity purchases resold	-	-	(216)	(182)	-	-	(216)	(182)
Depreciation and amortization	(251)	(258)	(90)	(87)	-	-	(341)	(345)
	445	489	179	207	(22)	(31)	602	665
Interest expense							(187)	(259)
Interest expense of joint ventures							(15)	(16)
Interest income and other							(18)	34
Income taxes							(65)	(97)
Non-controlling interests							(22)	(13)
<b>Net Income</b>							295	314
Preferred share dividends							(10)	-
<b>Net Income Applicable to Common Shares</b>							285	314

Six months ended June 30 <i>(unaudited)(millions of dollars)</i>	Pipelines		Energy <sup>(1)</sup>		Corporate		Total	
	2010	2009	2010	2009	2010	2009	2010	2009
Revenues	2,190	2,406	1,688	1,740	-	-	3,878	4,146
Plant operating costs and other	(726)	(788)	(737)	(758)	(48)	(61)	(1,511)	(1,607)
Commodity purchases resold	-	-	(472)	(411)	-	-	(472)	(411)
Depreciation and amortization	(504)	(518)	(180)	(173)	-	-	(684)	(691)
	960	1,100	299	398	(48)	(61)	1,211	1,437
Interest expense							(369)	(554)
Interest expense of joint ventures							(31)	(30)
Interest income and other							6	56
Income taxes							(166)	(213)
Non-controlling interests							(53)	(48)
<b>Net Income</b>							598	648
Preferred share dividends							(17)	-
<b>Net Income Applicable to Common Shares</b>							581	648

<sup>(1)</sup> Effective January 1, 2010, the Company records in Revenues on a net basis, realized and unrealized gains and losses on derivatives used to purchase and sell power, natural gas and fuel oil in order to manage Energy's assets. Comparative figures for 2009 reflect amounts reclassified from Commodity Purchases Resold to Revenues.

### Total Assets

*(unaudited)*  
*(millions of dollars)*

	June 30, 2010	December 31, 2009
Pipelines	31,005	29,508
Energy	12,798	12,477
Corporate	2,225	1,856
	46,028	43,841

### 4. Long-Term Debt

In June 2010, TCPL issued senior notes of US\$500 million and US\$750 million maturing on June 1, 2015 and June 1, 2040, respectively, and bearing interest at 3.40 per cent and 6.10 per cent, respectively. These notes were issued under the US\$4.0 billion debt shelf prospectus filed in December 2009.



In the three and six months ended June 30, 2010, the Company capitalized interest related to capital projects of \$143 million and \$277 million, respectively (2009 - \$63 million and \$117 million).

## 5. Share Capital

### *Preferred Share Issuances*

In June 2010, TransCanada completed a public offering of 14 million Series 5 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares, under its September 2009 base shelf prospectus. The preferred shares were issued at a price of \$25 per share, resulting in gross proceeds of \$350 million including the underwriters' option. The holders of the Series 5 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of \$1.10 per share, payable quarterly, yielding 4.4 per cent per annum for the initial five and a half year period ending January 30, 2016. The first dividend payment will be made on November 1, 2010. The dividend rate will reset on January 30, 2016 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 1.54 per cent. The Series 5 preferred shares are redeemable by TransCanada on January 30, 2016 and on January 30 of every fifth year thereafter.

The Series 5 preferred shareholders will have the right to convert their shares into Series 6 cumulative redeemable first preferred shares on January 30, 2016 and on January 30 of every fifth year thereafter. The holders of Series 6 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 1.54 per cent.

In March 2010, TransCanada completed a public offering of 14 million Series 3 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares, under its September 2009 base shelf prospectus. The preferred shares were issued at a price of \$25 per share, resulting in gross proceeds of \$350 million including the underwriters' option. The holders of the Series 3 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of \$1.00 per share, payable quarterly, yielding four per cent per annum for the initial five year period ending June 30, 2015. The first dividend payment was made on June 30, 2010. The dividend rate will reset on June 30, 2015 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 1.28 per cent. The Series 3 preferred shares are redeemable by TransCanada on June 30, 2015 and on June 30 of every fifth year thereafter.

The Series 3 preferred shareholders will have the right to convert their shares into Series 4 cumulative redeemable first preferred shares on June 30, 2015 and on June 30 of every fifth year thereafter. The holders of Series 4 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 1.28 per cent.

### *Dividend Reinvestment and Share Purchase Plan*

In the three and six months ended June 30, 2010, TransCanada issued 2.6 million and 4.9 million (2009 – 1.4 million and 3.5 million) common shares, respectively, under its Dividend Reinvestment and Share Purchase Plan (DRP), in lieu of making cash dividend payments of \$92 million and \$170 million (2009 - \$42 million and \$109 million). The dividends under the DRP were paid with common shares issued from treasury.

## 6. Financial Instruments and Risk Management

TransCanada continues to manage and monitor its exposure to counterparty credit, liquidity and market risk.

### *Counterparty Credit and Liquidity 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, the fair value of derivative assets and notes, loans and advances receivable. The carrying amounts and fair values of these financial assets are included in Accounts Receivable and Other in the Non-Derivative Financial Instruments Summary table below. Letters of credit and cash are the primary types of security provided to support these amounts. The majority of counterparty credit exposure is with counterparties who are investment grade. At June 30, 2010, there were no significant amounts past due or impaired.

At June 30, 2010, the Company had a credit risk concentration of \$348 million due from a creditworthy counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

The Company continues to manage its liquidity risk by ensuring sufficient cash and credit facilities are available to meet its operating and capital expenditure obligations when due, under both normal and stressed economic conditions.

### *Natural Gas Inventory*

At June 30, 2010, the fair value of proprietary natural gas inventory held in storage, as measured using a weighted average of forward prices for the following four months less selling costs, was \$51 million (December 31, 2009 - \$73 million). The change in fair value of proprietary natural gas inventory in storage in the three and six months ended June 30, 2010 resulted in net pre-tax unrealized gains of \$4 million and net pre-tax unrealized losses of \$20 million, respectively, which were recorded as an increase and a decrease, respectively, to Revenues and Inventories (2009 - losses of \$6 million and \$29 million). The change in fair value of natural gas forward purchase and sale contracts in the three and six months ended June 30, 2010 resulted in net pre-tax unrealized gains of \$2 million and \$5 million, respectively (2009 - losses of \$1 million and gains of \$9 million), which were included in Revenues.

### *VaR Analysis*

TransCanada uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its open liquid positions. VaR represents the potential change in pre-tax earnings over a given holding period. It is calculated assuming a 95 per cent confidence level that the daily change resulting from normal market fluctuations in its open positions will not exceed the reported VaR. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR. TransCanada's consolidated VaR was \$7 million at June 30, 2010 (December 31, 2009 - \$12 million). The decrease from December 31, 2009 was primarily due to decreased prices and lower open positions in the U.S. Power portfolio.

### *Net Investment in Self-Sustaining Foreign Operations*

The Company hedges its net investment in self-sustaining 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. At June 30, 2010, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of \$9.4 billion (US\$8.8 billion) and a fair value of \$9.7 billion (US\$9.2 billion). At June 30, 2010, \$20 million (December 31, 2009 - \$96 million) was included in Intangibles and Other Assets for the fair value of forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

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

#### Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

Asset/(Liability) ( <i>unaudited</i> ) ( <i>millions of dollars</i> )	June 30, 2010		December 31, 2009	
	Fair Value <sup>(1)</sup>	Notional or Principal Amount	Fair Value <sup>(1)</sup>	Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2010 to 2014)	37	U.S. 2,100	86	U.S. 1,850
U.S. dollar forward foreign exchange contracts (maturing 2010)	(17)	U.S. 550	9	U.S. 765
U.S. dollar foreign exchange options (matured 2010)	-	-	1	U.S. 100
	<b>20</b>	<b>U.S. 2,650</b>	<b>96</b>	<b>U.S. 2,715</b>

(1) Fair values equal carrying values.

#### Non-Derivative Financial Instruments Summary

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

(unaudited) ( <i>millions of dollars</i> )	June 30, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
<b>Financial Assets<sup>(1)</sup></b>				
Cash and cash equivalents	1,211	1,211	997	997
Accounts receivable and other <sup>(2)(3)</sup>	1,342	1,383	1,432	1,483
Available-for-sale assets <sup>(2)</sup>	20	20	23	23
	<b>2,573</b>	<b>2,614</b>	<b>2,452</b>	<b>2,503</b>
<b>Financial Liabilities<sup>(1)(3)</sup></b>				
Notes payable	1,697	1,697	1,687	1,687
Accounts payable and deferred amounts <sup>(4)</sup>	1,287	1,287	1,538	1,538
Accrued interest	374	374	377	377
Long-term debt	17,845	21,125	16,664	19,377
Junior subordinated notes	1,050	1,072	1,036	976
Long-term debt of joint ventures	911	1,011	965	1,025
	<b>23,164</b>	<b>26,566</b>	<b>22,267</b>	<b>24,980</b>

(1) Consolidated Net Income in 2010 included gains of \$9 million (2009 - \$8 million) for fair value adjustments related to interest rate swap agreements on US\$150 million (2009 - US\$300 million) of long-term debt. There were no other unrealized gains or losses from fair value adjustments to the financial instruments.

(2) At June 30, 2010, the Consolidated Balance Sheet included financial assets of \$867 million (December 31, 2009 - \$966 million) in Accounts Receivable, \$42 million in Other Current Assets (December 31, 2009 - nil) and \$453 million (December 31, 2009 - \$489 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost, except for certain long-term debt which is recorded at fair value.

(4) At June 30, 2010, the Consolidated Balance Sheet included financial liabilities of \$1,258 million (December 31, 2009 – \$1,513 million) in Accounts Payable and \$29 million (December 31, 2009 - \$25 million) in Deferred Amounts.

### Derivative Financial Instruments Summary

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

June 30, 2010

(unaudited)

(all amounts in millions unless otherwise indicated)

	Power	Natural Gas	Foreign Exchange	Interest
<b>Derivative Financial Instruments Held for Trading<sup>(1)</sup></b>				
Fair Values <sup>(2)</sup>				
Assets	\$210	\$146	-	\$29
Liabilities	\$(158)	\$(145)	\$(20)	\$(90)
Notional Values				
Volumes <sup>(3)</sup>				
Purchases	13,165	117	-	-
Sales	14,285	89	-	-
Canadian dollars	-	-	-	960
U.S. dollars	-	-	U.S. 1,143	U.S. 1,525
Cross-currency	-	-	47/U.S. 37	-
Net unrealized (losses)/gains in the period <sup>(4)</sup>				
Three months ended June 30, 2010	\$(10)	\$3	\$(11)	\$(13)
Six months ended June 30, 2010	\$(26)	\$5	\$(11)	\$(17)
Net realized gains/(losses) in the period <sup>(4)</sup>				
Three months ended June 30, 2010	\$15	\$(17)	\$(6)	\$(6)
Six months ended June 30, 2010	\$37	\$(29)	\$2	\$(10)
Maturity dates	2010-2015	2010-2014	2010-2012	2010-2018
<b>Derivative Financial Instruments in Hedging Relationships<sup>(5)(6)</sup></b>				
Fair Values <sup>(2)</sup>				
Assets	\$124	\$1	-	\$9
Liabilities	\$(237)	\$(54)	\$(37)	\$(116)
Notional Values				
Volumes <sup>(3)</sup>				
Purchases	14,792	63	-	-
Sales	15,209	-	-	-
U.S. dollars	-	-	U.S. 120	U.S. 1,975
Cross-currency	-	-	136/U.S. 100	-
Net realized losses in the period <sup>(4)</sup>				
Three months ended June 30, 2010	\$(36)	\$(6)	-	\$(9)
Six months ended June 30, 2010	\$(43)	\$(9)	-	\$(19)
Maturity dates	2010-2015	2010-2012	2010- 2014	2011-2020

(1) All derivative financial instruments in the held-for-trading classification 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 billion cubic feet (Bcf), respectively.

(4) Realized and unrealized gains and losses on power and natural gas derivative financial instruments held for trading are included 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 unrealized gains and losses on

derivative financial instruments in hedging relationships are initially recognized in Other Comprehensive Income and are 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 \$9 million and a notional amount of US\$150 million. Net realized gains on fair value hedges for the three and six months ended June 30, 2010 were \$1 million and \$2 million, respectively, and were included in Interest Expense. In second quarter 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.
- (6) Net Income for the three and six months ended June 30, 2010 included gains of \$7 million and losses of \$1 million, respectively, for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. There were no gains or losses included in Net Income for the three and six months ended June 30, 2010 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

**2009***(unaudited)**(all amounts in millions unless otherwise indicated)*

	Power	Natural Gas	Oil Products	Foreign Exchange	Interest
<b>Derivative Financial Instruments Held for Trading</b>					
Fair Values <sup>(1)(2)</sup>					
Assets	\$150	\$107	\$5	-	\$25
Liabilities	\$(98)	\$(112)	\$(5)	\$(66)	\$(68)
Notional Values <sup>(2)</sup>					
Volumes <sup>(3)</sup>					
Purchases	15,275	238	180	-	-
Sales	13,185	194	180	-	-
Canadian dollars	-	-	-	-	574
U.S. dollars	-	-	-	U.S. 444	U.S. 1,325
Cross-currency	-	-	-	227/U.S. 157	-
Net unrealized (losses)/gains in the period <sup>(4)</sup>					
Three months ended June 30, 2009	\$(2)	\$10	\$(5)	\$1	\$27
Six months ended June 30, 2009	\$19	\$(25)	\$2	\$2	\$27
Net realized gains/(losses) in the period <sup>(4)</sup>					
Three months ended June 30, 2009	\$20	\$(39)	\$2	\$11	\$(5)
Six months ended June 30, 2009	\$30	\$(13)	\$(1)	\$17	\$(9)
Maturity dates <sup>(2)</sup>	2010-2015	2010-2014	2010	2010-2012	2010-2018
<b>Derivative Financial Instruments in Hedging Relationships<sup>(5)(6)</sup></b>					
Fair Values <sup>(1)(2)</sup>					
Assets	\$175	\$2	-	-	\$15
Liabilities	\$(148)	\$(22)	-	\$(43)	\$(50)
Notional Values <sup>(2)</sup>					
Volumes <sup>(3)</sup>					
Purchases	13,641	33	-	-	-
Sales	14,311	-	-	-	-
U.S. dollars	-	-	-	U.S. 120	U.S. 1,825
Cross-currency	-	-	-	136/U.S. 100	-
Net realized gains/(losses) in the period <sup>(4)</sup>					
Three months ended June 30, 2009	\$52	\$(10)	-	-	\$(10)
Six months ended June 30, 2009	\$78	\$(20)	-	-	\$(17)
Maturity dates <sup>(2)</sup>	2010-2015	2010-2014	n/a	2010-2014	2010-2020

(1) Fair values equal carrying values.

(2) As at December 31, 2009.

(3) Volumes for power, natural gas and oil products derivatives are in GWh, Bcf and thousands of barrels, respectively.

(4) Realized and unrealized gains and losses on power, natural gas and oil products derivative financial instruments held for trading are included 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 unrealized gains and losses

on derivative financial instruments in hedging relationships are initially recognized in Other Comprehensive Income, and are 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 \$4 million and a notional amount of US\$150 million at December 31, 2009. Net realized gains on fair value hedges for the three and six months ended June 30, 2009 were \$1 million and \$2 million, respectively, and were included in Interest Expense. In second quarter 2009, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.
- (6) Net Income for the three and six months ended June 30, 2009 included losses of \$4 million and gains of \$1 million, respectively, for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. There were no gains or losses included in Net Income for the three and six months ended June 30, 2009 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

### *Balance Sheet Presentation of Derivative Financial Instruments*

The fair value of the derivative financial instruments in the Company's Balance Sheet was as follows:

<i>(unaudited)</i> <i>(millions of dollars)</i>	June 30, 2010	December 31, 2009
<b>Current</b>		
Other current assets	311	315
Accounts payable	(406)	(340)
<b>Long-term</b>		
Intangibles and other assets	228	260
Deferred amounts	(451)	(272)

### *Fair Value Hierarchy*

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based on a fair value hierarchy. Fair value of assets and liabilities included in Level I is determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level II include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. This category includes fair value determined using valuation techniques, such as option pricing models and extrapolation using observable inputs. Level III valuations are based on inputs that are not readily observable and are significant to the overall fair value measurement. Long-dated commodity transactions in certain markets and the fair value of guarantees are included in this category. Long-dated commodity prices are derived with a third-party modelling tool that uses market fundamentals to derive long-term prices. The fair value of guarantees is estimated by discounting the cash flows that would be incurred if letters of credit were used in place of the guarantees.

Financial assets and liabilities measured at fair value as of June 30, 2010, including both current and non-current portions, are categorized as follows. There were no transfers between Level I and Level II in second quarter 2010.

<i>(unaudited)</i> <i>(millions of dollars, pre-tax)</i>	Quoted Prices in Active Markets (Level I)	Significant Other Observable Inputs (Level II)	Significant Unobservable Inputs (Level III)	Total
Natural Gas Inventory	-	51	-	51
Derivative Financial Instruments:				
Assets	90	480	17	587
Liabilities	(187)	(696)	(22)	(905)
Available-for-sale assets	20	-	-	20
Guarantee Liabilities <sup>(1)</sup>	-	-	(9)	(9)
	<u>(77)</u>	<u>(165)</u>	<u>(14)</u>	<u>(256)</u>

(1) The fair value of guarantees is included in Deferred Amounts.

The following table presents the net change in financial assets and liabilities measured at fair value and included in the Level III fair value category:

<i>(unaudited)</i> <i>(millions of dollars, pre-tax)</i>	Derivatives <sup>(1)</sup>	Guarantees <sup>(2)</sup>	Total
Balance at December 31, 2009	(2)	(9)	(11)
New contracts <sup>(3)</sup>	(10)	-	(10)
Settlements	(2)	-	(2)
Transfers out of Level III <sup>(4)</sup>	(15)	-	(15)
Change in unrealized gains recorded in Net Income	14	-	14
Change in unrealized gains recorded in Other Comprehensive Income	10	-	10
<b>Balance at June 30, 2010</b>	<u>(5)</u>	<u>(9)</u>	<u>(14)</u>

(1) The fair value of derivative assets and liabilities is presented on a net basis.

(2) The fair value of guarantees is included in Deferred Amounts. No amounts were recognized in Net Income for the periods presented.

(3) The total amount of net gains included in Net Income attributable to derivatives that were entered into during the period and still held at the reporting date was \$1 million and nil for the three and six months ended June 30, 2010, respectively.

(4) As contracts near maturity, they are transferred out of Level III to Level II.

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a \$28 million decrease or increase, respectively, in the fair value of derivative financial instruments included in Level III and outstanding as at June 30, 2010.

A 100 basis points increase or decrease in the letter of credit rate, with all other variables held constant, would result in a \$3 million increase or decrease, respectively, in the fair value of guarantee liabilities outstanding as at June 30, 2010. Similarly, the effect of a 100 basis points increase or decrease in the risk-free interest rate, which is a component of the discount rate, on the fair value of guarantee liabilities outstanding as at June 30, 2010 would result in a \$1 million decrease or increase, respectively, in the liability.

## 7. Employee Future Benefits

The net benefit plan expense for the Company's defined benefit pension plans and other post-employment benefit plans is as follows:

Three months ended June 30 <i>(unaudited)(millions of dollars)</i>	Pension Benefit Plans		Other Benefit Plans	
	2010	2009	2010	2009
Current service cost	13	12	1	1
Interest cost	22	22	2	2
Expected return on plan assets	(27)	(26)	(1)	(1)
Amortization of transitional obligation related to regulated business	-	-	1	1
Amortization of net actuarial loss	2	1	1	1
Amortization of past service costs	1	1	-	-
Net benefit cost recognized	11	10	4	4

Six months ended June 30 <i>(unaudited)(millions of dollars)</i>	Pension Benefit Plans		Other Benefit Plans	
	2010	2009	2010	2009
Current service cost	25	23	1	1
Interest cost	45	45	4	4
Expected return on plan assets	(54)	(51)	(1)	(1)
Amortization of transitional obligation related to regulated business	-	-	1	1
Amortization of net actuarial loss	4	2	1	1
Amortization of past service costs	2	2	-	-
Net benefit cost recognized	22	21	6	6

## 8. Commitments and Contingencies

At June 30, 2010, TransCanada had entered into agreements totalling approximately \$530 million to purchase construction materials and services for the Bison natural gas pipeline and Cartier Wind power projects.

Amounts received under the Bruce B floor price mechanism in any year are subject to repayment if average spot prices exceed the floor price. With respect to 2010, TransCanada currently expects average spot prices to be less than the floor price for the remainder of the year, therefore, no amounts recorded in revenue in the first six months of 2010 are expected to be repaid.

TransCanada welcomes questions from shareholders and potential investors. Please telephone:

Investor Relations, at (800) 361-6522 (Canada and U.S. Mainland) or direct dial David Moneta/ Terry Hook at (403) 920-7911. The investor fax line is (403) 920-2457. Media Relations: Cecily Dobson/Terry Cunha (403) 920-7859 or (800) 608-7859.

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