Quarterly Report to Shareholders

Management's Discussion and Analysis

Management's Discussion and Analysis (MD&A) dated July 28, 2011 should be read in conjunction with the accompanying unaudited Consolidated Financial Statements of TransCanada PipeLines (TCPL or the Company) for the three and six months ended June 30, 2011. In 2011, the Company will prepare its consolidated financial statements in accordance with Canadian generally accepted accounting principles (GAAP) as defined in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook, which is discussed further in the Changes in Accounting Policies section in this MD&A. This MD&A should also be read in conjunction with the audited Consolidated Financial Statements and notes thereto, and the MD&A contained in TCPL's 2010 Annual Report for the year ended December 31, 2010. Additional information relating to TCPL, including the Company's Annual Information Form and other continuous disclosure documents, is available on SEDAR at www.sedar.com under TCPL PipeLines Limited's profile. "TCPL" or "the Company" includes TransCanada PipeLines Limited and its subsidiaries, unless otherwise indicated. Amounts are stated in Canadian dollars unless otherwise indicated. Abbreviations and acronyms used but not otherwise defined in this MD&A are identified in the Glossary of Terms contained in TCPL's 2010 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 TCPL security holders and potential investors with information regarding TCPL and its subsidiaries, including management's assessment of TCPL'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 TCPL 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), and operating and financial results, and expected impact of future commitments and contingent liabilities. All forward-looking statements reflect TCPL'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 TCPL 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, including those material risks discussed in the Financial Instruments and Risk Management section in this MD&A, which could cause TCPL'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 TCPL 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 specified, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TCPL 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

TCPL uses the measures Comparable Earnings, Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA), Comparable EBITDA, Earnings Before Interest and Taxes (EBIT), Comparable EBIT, Comparable Interest Expense, Comparable Interest Income and Other, Comparable Income Taxes and Funds Generated from Operations in this MD&A. These measures do not have any standardized meaning prescribed by GAAP. They are, therefore, considered to be non-GAAP measures and may not be comparable to similar measures presented by other entities. Management of TCPL 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 TCPL'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 and is generally used to better measure performance and evaluate trends of individual assets. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, net income attributable to non-controlling interests and preferred share dividends. EBIT is a measure of the Company's earnings from ongoing operations and is generally used to better measure performance and evaluate trends within each segment. EBIT comprises earnings before deducting interest and other financial charges, income taxes, net income attributable to non-controlling interests and preferred share dividends.

Comparable Earnings, Comparable EBITDA, Comparable EBIT, Comparable Interest Expense, Comparable Interest Income and Other, and Comparable Income Taxes comprise Net Income Attributable to Common Shares, EBITDA, EBIT, Interest Expense, Interest Income and Other, and Income Taxes Expense, 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 these non-GAAP measures, some of which may recur. Specific items may include but are not limited to certain fair value adjustments relating to risk management activities, income tax refunds and adjustments, gains or losses on sales of assets, legal and bankruptcy settlements, and write-downs of assets and investments.

The Company engages in risk management activities to reduce its exposure to certain financial and commodity price risks by utilizing instruments such as derivatives. The risk management activities, which TCPL excludes from Comparable Earnings, provide effective economic hedges but do not meet the specific criteria for hedge accounting treatment and, therefore, changes in their fair values are recorded in Net Income each period. The unrealized gains or losses from changes in the fair value of these derivative contracts and natural gas inventory in storage are not considered to be representative of the underlying operations in the current period or the positive margin that will be realized upon settlement. As a result, these amounts have been excluded in the determination of Comparable Earnings.

The tables below present a reconciliation of these non-GAAP measures to Net Income Attributable to Common Shares.

Funds Generated from Operations comprise Net Cash Provided by Operations before changes in operating working capital and allows management to better measure consolidated operating cash flow, excluding fluctuations from working capital balances which may not necessarily be reflective of underlying operations in the same period. 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 in this MD&A.

Reconciliation of Non-GAAP Measures

For the three months ended June 30 *(unaudited)* *(millions of dollars)*	Natural Gas Pipelines		Oil Pipelines		Energy		Corporate		Total	
	2011	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Comparable EBITDA	**711**	696	**153**	-	**290**	254	**(15)**	(22)	**1,139**	928
Depreciation and amortization	**(244)**	(251)	**(34)**	-	**(97)**	(90)	**(4)**	-	**(379)**	(341)
Comparable EBIT	**467**	445	**119**	-	**193**	164	**(19)**	(22)	**760**	587
Other Income Statement Items										
Comparable interest expense									**(263)**	(198)
Interest expense of joint ventures									**(11)**	(15)
Comparable interest income and other									**26**	(18)
Comparable income taxes									**(132)**	(57)
Net income attributable to non-controlling interests									**(23)**	(17)
Preferred share dividends									**(5)**	(5)
Comparable Earnings									**352**	277
Specific item (net of tax):										
Risk management activities(1)									**(4)**	10
Net Income Attributable to Common Shares									**348**	287

For the three months ended June 30 *(unaudited)(millions of dollars)*	**2011**	2010
Comparable Interest Expense	**(263)**	(198)
Specific item:		
Risk management activities(1)	**1**	-
Interest Expense	**(262)**	(198)
Comparable Interest Income and Other	**26**	(18)
Specific item:		
Risk management activities(1)	**(3)**	-
Interest Income and Other	**23**	(18)
Comparable Income Taxes	**(132)**	(57)
Specific item:		
Income taxes attributable to risk management activities(1)	**1**	(5)
Income Taxes Expense	**(131)**	(62)

(1)

For the three months ended June 30 *(unaudited)(millions of dollars)*	**2011**	2010
Risk Management Activities Gains/(Losses):		
U.S. Power derivatives	**1**	9
Natural Gas Storage proprietary inventory and derivatives	**(4)**	6
Interest rate derivatives	**1**	-
Foreign exchange derivatives	**(3)**	-
Income taxes attributable to risk management activities	**1**	(5)
Risk Management Activities	**(4)**	10

For the six months ended June 30 *(unaudited)* *(millions of dollars)*	Natural Gas Pipelines 2011	2010	Oil Pipelines 2011	2010	Energy 2011	2010	Corporate 2011	2010	Total 2011	2010
Comparable EBITDA	**1,507**	1,464	**252**	-	**644**	513	**(39)**	(48)	**2,364**	1,929
Depreciation and amortization	**(488)**	(504)	**(57)**	-	**(197)**	(180)	**(7)**	-	**(749)**	(684)
Comparable EBIT	**1,019**	960	**195**	-	**447**	333	**(46)**	(48)	**1,615**	1,245
Other Income Statement Items										
Comparable interest expense									**(501)**	(392)
Interest expense of joint ventures									**(27)**	(31)
Comparable interest income and other									**57**	6
Comparable income taxes									**(310)**	(171)
Net income attributable to non-controlling interests									**(53)**	(42)
Preferred share dividends									**(11)**	(11)
Comparable Earnings									**770**	604
Specific item (net of tax):										
Risk management activities[(1)]									**(14)**	(22)
Net Income Attributable to Common Shares									**756**	582

For the six months ended June 30 *(unaudited)(millions of dollars)*	2011	2010
Comparable Interest Expense	**(501)**	(392)
Specific item:		
Risk management activities[(1)]	**-**	-
Interest Expense	**(501)**	(392)
Comparable Interest Income and Other	**57**	6
Specific item:		
Risk management activities[(1)]	**(1)**	-
Interest Income and Other	**56**	6
Comparable Income Taxes	**(310)**	(171)
Specific item:		
Income taxes attributable to risk management activities[(1)]	**8**	12
Income Taxes Expense	**(302)**	(159)

(1)

For the six months ended June 30 *(unaudited)(millions of dollars)*	2011	2010
Risk Management Activities (Losses)/ Gains:		
U.S. Power derivatives	**(12)**	(19)
Natural Gas Storage proprietary inventory and derivatives	**(9)**	(15)
Foreign exchange derivatives	**(1)**	-
Income taxes attributable to risk management activities	**8**	12
Risk Management Activities	**(14)**	(22)

Consolidated Results of Operations

TCPL's Net Income Attributable to Controlling Interests in second quarter 2011 was $353 million and Net Income Attributable to Common Shares was $348 million compared to $292 million and $287 million, respectively, in second quarter 2010.

Comparable Earnings in second quarter 2011 were $352 million compared to $277 million for the same period in 2010. Comparable Earnings in second quarter 2011 excluded net unrealized after-tax losses of $4 million ($5 million pre-tax) (2010 – gains of $10 million after tax ($15 million pre-tax)) resulting from changes in the fair value of certain risk management activities.

Comparable Earnings increased $75 million in second quarter 2011 compared to the same period in 2010 and reflected the following:

- increased Natural Gas Pipelines Comparable EBIT primarily due to higher earnings from ANR and the Alberta System, and incremental earnings from Bison and Guadalajara which were placed in service in January 2011 and June 2011, respectively, partially offset by the negative impact of a weaker U.S. dollar on U.S. operations and increased operations, maintenance and administrative (OM&A) costs;

- Oil Pipelines Comparable EBIT as the Company commenced recording earnings from Keystone in first quarter 2011;

- increased Energy Comparable EBIT primarily due to higher volumes and realized prices at Bruce A, incremental earnings from the start-up of Halton Hills in September 2010 and Coolidge in May 2011, and higher capacity payments and realized prices in U.S. Power, partially offset by lower prices for Western Power and lower volumes and realized prices at Bruce B;

- increased Comparable Interest Expense primarily due to decreased capitalized interest for Keystone and Halton Hills, and incremental interest expense on new debt issues in 2010, partially offset by realized gains in second quarter 2011 compared to losses in second quarter 2010 on derivatives used to manage the Company's exposure to fluctuating interest rates, and the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest expense;

- increased Comparable Interest Income and Other, which included realized gains in second quarter 2011 compared to losses in second quarter 2010 on derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income; and

- increased Comparable Income Taxes primarily due to higher pre-tax earnings in second quarter 2011 compared to second quarter 2010 and higher positive income tax adjustments in second quarter 2010.

TCPL's Net Income Attributable to Controlling Interests in the first six months of 2011 was $767 million and Net Income Attributable to Common Shares was $756 million compared to $593 million and $582 million, respectively, for the same period in 2010.

Comparable Earnings in the first six months of 2011 were $770 million compared to $604 million for the same period in 2010. Comparable Earnings for the first six months of 2011 excluded net unrealized after-tax losses of $14 million ($22 million pre-tax) (2010 – after-tax losses of $22 million ($34 million pre-tax)) resulting from changes in the fair value of certain risk management activities.

Comparable Earnings increased $166 million in the first six months of 2011 compared to the same period in 2010 and reflected the following:

- increased EBIT from Natural Gas Pipelines primarily due to incremental earnings from Bison and Guadalajara, which were placed in service in January 2011 and June 2011, respectively, higher earnings from the Alberta System and reduced business development costs relating to the Alaska Pipeline Project, partially offset by the negative impact of a weaker U.S. dollar and increased OM&A costs;

- Oil Pipelines Comparable EBIT as the Company commenced recording earnings from Keystone in first quarter 2011;

- increased EBIT from Energy primarily due to higher volumes and lower operating expenses due to reduced outage days, and higher realized prices at Bruce A, higher overall realized prices at Western Power, incremental earnings from the start-up of Halton Hills in September 2010, Coolidge in May 2011 and Kibby Wind in October 2011, and higher revenues from U.S. Power, partially offset by lower realized prices and reduced volumes at Bruce B, and decreased proprietary and third-party storage revenues for Natural Gas Storage;

- increased Comparable Interest Expense primarily due to decreased capitalized interest for Keystone and Halton Hills, and incremental interest expense on new debt issues in 2010, partially offset by realized gains in 2011 compared to losses in 2010 on derivatives used to manage the Company's exposure to fluctuating interest rates, the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest expense and Canadian debt maturities in 2011 and 2010;

- increased Comparable Interest Income and Other, which included realized gains in 2011 compared to losses in 2010 on derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income; and

- increased Comparable Income Taxes primarily due to higher pre-tax earnings in 2011 compared to 2010 and higher positive income tax adjustments in 2010.

Further discussion of the significant financial results in the first three and six months in 2011 is included in the Natural Gas Pipelines, Oil Pipelines, Energy and Other Income Statement Items sections in this MD&A.

U.S. Dollar-Denominated Balances

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. operations is partially offset by other U.S. dollar-denominated items as set out in the following table. The resultant pre-tax net exposure is managed using derivatives, further reducing the Company's exposure to changes in Canadian-U.S. foreign exchange rates. The average U.S. dollar to Canadian dollar exchange rate for the three and six months ended June 30, 2011 was 0.97 and 0.98, respectively (2010 – 1.03 and 1.03, respectively).

Summary of Significant U.S. Dollar-Denominated Amounts

(unaudited)	Three months ended June 30		Six months ended June 30	
(millions of U.S. dollars, pre-tax)	**2011**	2010	**2011**	2010
U.S. Natural Gas Pipelines Comparable EBIT[(1)]	**175**	147	**424**	373
U.S. Oil Pipelines Comparable EBIT[(1)]	**81**	-	**132**	-
U.S. Power Comparable EBIT[(1)]	**65**	42	**97**	81
Interest on U.S. dollar-denominated long-term debt	**(180)**	(163)	**(362)**	(322)
Capitalized interest on U.S capital expenditures	**25**	65	**72**	133
U.S. non-controlling interests and other	**(44)**	(36)	**(95)**	(81)
	122	55	**268**	184

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

Natural Gas Pipelines

Natural Gas Pipelines' Comparable EBIT was $467 million and $1.0 billion in the three and six months ended June 30, 2011, respectively, compared to $445 million and $960 million, respectively, for the same periods in 2010.

Natural Gas Pipelines Results

(unaudited) *(millions of dollars)*	Three months ended June 30 **2011**	2010	Six months ended June 30 **2011**	2010
Canadian Natural Gas Pipelines				
Canadian Mainline	**267**	263	**532**	528
Alberta System	**181**	176	**366**	351
Foothills	**32**	35	**65**	68
Other (TQM, Ventures LP)	**13**	14	**25**	27
Canadian Natural Gas Pipelines Comparable EBITDA[1]	**493**	488	**988**	974
Depreciation and amortization	**(181)**	(185)	**(361)**	(368)
Canadian Natural Gas Pipelines Comparable EBIT[1]	**312**	303	**627**	606
U.S. Natural Gas Pipelines (in U.S. dollars)				
ANR	**70**	59	**181**	174
GTN[2]	**31**	40	**76**	83
Great Lakes[3]	**25**	25	**55**	57
PipeLines LP[4][5]	**23**	22	**50**	47
Iroquois	**16**	17	**35**	35
Bison[2][6]	**14**	-	**27**	-
Portland[5][7]	**3**	1	**13**	11
International (Tamazunchale, Guadalajara TransGas, Gas Pacifico/INNERGY)[8]	**15**	14	**25**	24
General, administrative and support costs[9]	**(2)**	(3)	**(4)**	(9)
Non-controlling interests[5]	**46**	36	**96**	82
U.S. Natural Gas Pipelines Comparable EBITDA[1]	**241**	211	**554**	504
Depreciation and amortization	**(66)**	(64)	**(130)**	(131)
U.S. Natural Gas Pipelines Comparable EBIT[1]	**175**	147	**424**	373
Foreign exchange	**(5)**	5	**(9)**	14
U.S. Natural Gas Pipelines Comparable EBIT[1] (in Canadian dollars)	**170**	152	**415**	387
Natural Gas Pipelines Business Development Comparable EBITDA[1]	**(15)**	(10)	**(23)**	(33)
Natural Gas Pipelines Comparable EBIT[1]	**467**	445	**1,019**	960
Summary:				
Natural Gas Pipelines Comparable EBITDA[1]	**711**	696	**1,507**	1,464
Depreciation and amortization	**(244)**	(251)	**(488)**	(504)
Natural Gas Pipelines Comparable EBIT[1]	**467**	445	**1,019**	960

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(2) Results reflect TCPL's direct ownership interest of 75 per cent effective May 3, 2011 and 100 per cent prior to that date.
(3) Represents the Company's 53.6 per cent direct ownership interest.
(4) Effective May 3, 2011, TCPL's ownership interest in PipeLines LP decreased from 38.2 per cent to 33.3 per cent. As a result, PipeLines LP's results include TCPL's decreased ownership in PipeLines LP and TCPL's effective ownership through PipeLines LP of 8.3 per cent of each of GTN and Bison since May 3, 2011.
(5) Non-Controlling Interests reflects Comparable EBITDA for the portions of PipeLines LP and Portland not owned by TCPL.
(6) Includes Bison's operations since January 2011.
(7) Represents the Company's 61.7 per cent ownership interest.
(8) Includes Guadalajara's operations since June 15, 2011.
(9) Represents General, Administrative and Support Costs associated with certain of the Company's pipelines.

Net Income for Wholly Owned Canadian Natural Gas Pipelines

(unaudited)	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2011**	2010	**2011**	2010
Canadian Mainline	**63**	64	**125**	130
Alberta System	**50**	37	**98**	75
Foothills	**6**	7	**12**	13

Canadian Natural Gas Pipelines

Canadian Mainline's net income for the three and six months ended June 30, 2011 decreased $1 million and $5 million, respectively, compared to the same periods in 2010 primarily due to a lower rate of return on common equity (ROE), as determined by the National Energy Board (NEB), of 8.08 per cent in 2011 compared to 8.52 per cent in 2010, as well as a lower average investment base. The impact of the lower ROE and average investment base was partially offset by higher incentive earnings in 2011.

Canadian Mainline's Comparable EBITDA for the three and six months ended June 30, 2011 of $267 million and $532 million, respectively, increased $4 million compared to each of the same periods in 2010. An increase in revenues as a result of higher incentive earnings and higher flow-through costs was partially offset by a lower overall return, associated with the reduced ROE and financial charges, on a reduced average investment base. The flow-through costs do not impact net income and increased primarily due to higher income taxes.

The Alberta System's net income was $50 million in second quarter 2011 and $98 million for the first six months of 2011 compared to $37 million and $75 million for the same periods in 2010. The increases reflect an ROE of 9.70 per cent on 40 per cent deemed common equity approved by the NEB in September 2010 as part of the Company's 2010 - 2012 Revenue Requirement Settlement application. Net income in 2010 reflected an ROE of 8.75 per cent on 35 per cent deemed common equity.

The Alberta System's Comparable EBITDA was $181 million in second quarter 2011 and $366 million for the first six months of 2011 compared to $176 million and $351 million for the same periods in 2010. The increases were primarily due to the increased ROE included in the 2010 - 2012 Revenue Requirement Settlement.

U.S. Natural Gas Pipelines

ANR's Comparable EBITDA for the three and six months ended June 30, 2011 was US$70 million and US$181 million, respectively, compared to US$59 million and US$174 million for the same periods in 2010. The increases were primarily due to higher transportation and storage revenues, a settlement with a counterparty and increased incidental commodity sales, partially offset by higher OM&A costs.

GTN's Comparable EBITDA for the three and six months ended June 30, 2011 was US$31 million and US$76 million, respectively, compared to US$40 million and US$83 million for the same periods in 2010. The decreases were primarily due to TCPL's sale of 25 per cent of GTN to PipeLines LP in May 2011.

The Bison pipeline was placed in service in January 2011. TCPL's portion of Comparable EBITDA was US$14 million and US$27 million for the three and six months ended June 30, 2011, respectively. EBIDTA reflects TCPL's sale of 25 per cent of Bison to PipeLines LP in May 2011.

Comparable EBITDA for the remainder of the U.S. Natural Gas Pipelines was US$157 million and US$346 million for the three and six months ended June 30, 2011, respectively, compared to US$152 million and US$333 million for the same periods in 2010. The increases were primarily due to higher revenues for Northern Border, lower general, administrative and support costs, and incremental earnings from the Guadalajara pipeline which was placed in service on June 15, 2011.

Depreciation

Natural Gas Pipelines' depreciation decreased $7 million and $16 million for the three and six months ended June 30, 2011, respectively, compared to the same periods in 2010. The decreases were primarily due to lower depreciation rates included in the Great Lakes and Alberta System rate settlements, and the effect of a weaker U.S. dollar on U.S. asset depreciation, partially offset by incremental depreciation for Bison.

Business Development

Natural Gas Pipelines' Business Development Comparable EBITDA loss increased $5 million and decreased $10 million in the three and six months ended June 30, 2011, respectively, compared to the same periods in 2010. Business development costs increased in second quarter 2011 compared to second quarter 2010 primarily due to greater activity in 2011 for the Alaska Pipeline Project, partially offset by a 90 per cent reimbursement by the State of Alaska for eligible project costs effective July 31, 2010 versus a 50 per cent reimbursement prior to this date. Business development costs in the first six months of 2011 were lower primarily due to the increased reimbursement by the State of Alaska. Project applicable expenses and reimbursements are shared proportionately with ExxonMobil, TCPL's joint venture partner in the Alaska Pipeline Project. The decrease in business development costs in the first six months of 2011 was partially offset by a levy charged by the NEB in March 2011 to recover the Aboriginal Pipeline Group's proportionate share of costs relating to the Mackenzie Gas Project hearings.

Operating Statistics

Six months ended June 30	Canadian Mainline[1]		Alberta System[2]		Foothills		ANR[3]	
(unaudited)	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Average investment base (millions of dollars)	**6,328**	6,572	**4,993**	4,975	**617**	666	**n/a**	n/a
Delivery volumes (Bcf)								
Total	**1,059**	844	**1,788**	1,723	**630**	680	**870**	795
Average per day	**5.9**	4.7	**9.9**	9.5	**3.5**	3.8	**4.8**	4.4

(1) Canadian Mainline's throughput volumes in the above table reflect physical deliveries to domestic and export markets. Canadian Mainline's physical receipts originating at the Alberta border and in Saskatchewan for the six months ended June 30, 2011 were 643 billion cubic feet (Bcf) (2010 – 645 Bcf); average per day was 3.6 Bcf (2010 – 3.6 Bcf).

(2) Field receipt volumes for the Alberta System for the six months ended June 30, 2011 were 1,733 Bcf (2010 – 1,740 Bcf); average per day was 9.6 Bcf (2010 – 9.6 Bcf).

(3) ANR'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.

Oil Pipelines

In the three and five months ended June 30, 2011, the Company recorded $119 million and $195 million, respectively, of Comparable EBIT related to the Oil Pipelines segment. In late January 2011, work was completed to allow Keystone to increase its operating pressure following the NEB's decision to remove the maximum operating pressure restriction along the conversion section of the system in December 2010. At the beginning of February 2011, the Company commenced recording EBITDA for the Wood River/Patoka section of Keystone and for the Cushing Extension, which was placed in service at that time.

Oil Pipelines Results

For the period February 1 to June 30 *(unaudited)(millions of dollars)*	Three months ended June 30, 2011	Five months ended June 30, 2011
Canadian Oil Pipelines Comparable EBITDA[1]	**55**	**90**
Depreciation and amortization	(13)	(22)
Canadian Oil Pipelines Comparable EBIT[1]	**42**	**68**
U.S. Oil Pipelines Comparable EBITDA[1] (in U.S. dollars)	**103**	**168**
Depreciation and amortization	(22)	(36)
U.S. Oil Pipelines Comparable EBIT[1]	**81**	**132**
Foreign exchange	(3)	(4)
U.S. Oil Pipelines Comparable EBIT[1] (in Canadian dollars)	**78**	**128**
Oil Pipelines Business Development Comparable EBITDA[1]	(1)	(1)
Oil Pipelines Comparable EBIT[1]	**119**	**195**
Summary:		
Oil Pipelines Comparable EBITDA[1]	**153**	**252**
Depreciation and amortization	(34)	(57)
Oil Pipelines Comparable EBIT[1]	**119**	**195**

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

Operating Statistics

For the period February 1 to June 30 *(unaudited)*	Three months ended June 30, 2011	Five months ended June 30, 2011
Delivery volumes (thousands of barrels)[1]		
Total	**30,167**	**52,633**
Average per day	**332**	**351**

(1) Delivery volumes reflect physical deliveries.

Energy

Energy's Comparable EBIT was $193 million and $447 million for the three and six months ended June 30, 2011, respectively, compared to $164 million and $333 million, respectively, for the same periods in 2010.

Energy Results

(unaudited) *(millions of dollars)*	Three months ended June 30 **2011**	 2010	Six months ended June 30 **2011**	 2010
Canadian Power				
Western Power[1]	**74**	85	**194**	127
Eastern Power[2]	**71**	46	**151**	98
Bruce Power	**56**	47	**133**	110
General, administrative and support costs	**(9)**	(5)	**(17)**	(15)
Canadian Power Comparable EBITDA[3]	**192**	173	**461**	320
Depreciation and amortization	**(69)**	(58)	**(136)**	(118)
Canadian Power Comparable EBIT[3]	**123**	115	**325**	202
U.S. Power (in U.S. dollars)				
Northeast Power[4]	**99**	78	**170**	151
General, administrative and support costs	**(10)**	(9)	**(19)**	(18)
U.S. Power Comparable EBITDA[3]	**89**	69	**151**	133
Depreciation and amortization	**(24)**	(27)	**(54)**	(52)
U.S. Power Comparable EBIT[3]	**65**	42	**97**	81
Foreign exchange	**(3)**	2	**(3)**	3
U.S. Power Comparable EBIT[3] (in Canadian dollars)	**62**	44	**94**	84
Natural Gas Storage				
Alberta Storage	**21**	20	**52**	73
General, administrative and support costs	**(3)**	(2)	**(5)**	(4)
Natural Gas Storage Comparable EBITDA[3]	**18**	18	**47**	69
Depreciation and amortization	**(4)**	(4)	**(8)**	(8)
Natural Gas Storage Comparable EBIT[3]	**14**	14	**39**	61
Energy Business Development Comparable EBITDA[3]	**(6)**	(9)	**(11)**	(14)
Energy Comparable EBIT[3]	**193**	164	**447**	333
Summary:				
Energy Comparable EBITDA[3]	**290**	254	**644**	513
Depreciation and amortization	**(97)**	(90)	**(197)**	(180)
Energy Comparable EBIT[3]	**193**	164	**447**	333

(1) Includes Coolidge effective May 2011.
(2) Includes Halton Hills effective September 2010.
(3) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(4) Includes phase two of Kibby Wind effective October 2010.

Canadian Power

Western and Eastern Canadian Power Comparable EBIT[(1)(2)]

(unaudited) *(millions of dollars)*	Three months ended June 30 **2011**	2010	Six months ended June 30 **2011**	2010
Revenues				
Western power	**182**	202	**461**	366
Eastern power	**113**	65	**231**	132
Other[(3)]	**18**	15	**41**	37
	313	282	**733**	535
Commodity Purchases Resold				
Western power	**(101)**	(99)	**(244)**	(205)
Other[(4)]	**(4)**	(7)	**(9)**	(12)
	(105)	(106)	**(253)**	(217)
Plant operating costs and other	**(63)**	(45)	**(135)**	(93)
General, administrative and support costs	**(9)**	(5)	**(17)**	(15)
Comparable EBITDA[(1)]	**136**	126	**328**	210
Depreciation and amortization	**(41)**	(32)	**(80)**	(69)
Comparable EBIT[(1)]	**95**	94	**248**	141

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(2) Includes Coolidge and Halton Hills effective May 2011 and September 2010, respectively.
(3) Includes sales of excess natural gas purchased for generation and thermal carbon black. The realized gains and losses from derivatives used to purchase and sell natural gas to manage Western and Eastern Power's assets are presented on a net basis in Other Revenues.
(4) Includes the cost of excess natural gas not used in operations.

Western and Eastern Canadian Power Operating Statistics

(unaudited)	Three months ended June 30 **2011**	2010	Six months ended June 30 **2011**	2010
Sales Volumes (GWh)				
Supply				
Generation				
Western Power[(1)]	**626**	594	**1,307**	1,179
Eastern Power[(2)]	**770**	395	**1,848**	824
Purchased				
Sundance A & B and Sheerness PPAs[(3)]	**1,855**	2,459	**3,960**	5,114
Other purchases	**174**	73	**376**	222
	3,425	3,521	**7,491**	7,339
Sales				
Contracted				
Western Power[(1)]	**2,038**	2,573	**4,307**	4,842
Eastern Power[(2)]	**770**	395	**1,848**	840
Spot				
Western Power	**617**	553	**1,336**	1,657
	3,425	3,521	**7,491**	7,339
Plant Availability[(4)]				
Western Power[(1)(5)]	**97%**	94%	**97%**	94%
Eastern Power[(2)(6)]	**92%**	97%	**95%**	97%

(1) Includes Coolidge effective May 2011.
(2) Includes Halton Hills effective September 2010.
(3) No volumes were delivered under the Sundance A PPA in 2011.
(4) Plant availability represents the percentage of time in a period that the plant is available to generate power regardless of whether it is running.
(5) Excludes facilities that provide power to TCPL under PPAs.
(6) Bécancour has been excluded from the availability calculation as power generation has been suspended since 2008.

Western Power's Comparable EBITDA of $74 million and Power Revenues of $182 million in second quarter 2011 decreased $11 million and $20 million, respectively, compared to the same period in 2010, primarily due to lower realized power prices in Alberta, partially offset by incremental earnings from Coolidge, which went into service under a 20-year power purchase arrangement (PPA) in May 2011. Average spot market power prices in Alberta decreased 35 per cent to $52 per megawatt hour (MWh) in second quarter 2011 compared to $80 per MWh in second quarter 2010 when certain unplanned plant and transmission outages resulted in significantly higher spot prices.

Western Power's Comparable EBITDA of $194 million and Power Revenues of $461 million in the first six months of 2011 increased $67 million and $95 million, respectively, compared to the same period in 2010 primarily due to higher overall realized prices and incremental earnings from Coolidge.

Western Power's Comparable EBITDA in the three and six months ended June 30, 2011 included $12 million and $51 million, respectively, of accrued earnings from the Sundance A PPA, the revenues and costs of which have been recorded as though Sundance A Units 1 and 2 were on normal plant outages. Refer to the Recent Developments section in this MD&A for further discussion regarding the Sundance A outage.

Western Power's Commodity Purchases Resold increased $39 million for the six months ended June 30, 2011 compared to the same period in 2010 primarily due to higher volumes at Sheerness and increased retail contracts.

Eastern Power's Comparable EBITDA of $71 million and $151 million for the three and six months ended June 30, 2011, respectively, increased $25 million and $53 million, respectively, compared to the same periods in 2010. Power Revenues of $113 million and $231 million for the three and six months ended June 30, 2011, respectively, increased $48 million and $99 million, respectively, compared to the same periods in 2010. The increases were primarily due to incremental earnings from Halton Hills, which went into service in September 2010.

Plant Operating Costs and Other of $63 million and $135 million for the three and six months ended June 30, 2011, respectively, which includes fuel gas consumed in power generation, increased $18 million and $42 million, respectively, compared to the same periods in 2010 primarily due to incremental fuel consumed at Halton Hills.

Depreciation and amortization increased $9 million and $11 million for the three and six months ended June 30, 2011, respectively, compared to the same periods in 2010 primarily due to incremental depreciation from Halton Hills and Coolidge.

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 sold 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 77 per cent of Western Power sales volumes were sold under contract in second quarter 2011, compared to 82 per cent in second quarter 2010. To reduce its exposure to spot market prices on uncontracted volumes, as at June 30, 2011, Western Power had entered into fixed-price power sales contracts to sell approximately 4,600 gigawatt hours (GWh) for the remainder of 2011 and 7,500 GWh for 2012.

Eastern Power is focused on selling power under long-term contracts. In second quarter 2011 and 2010, 100 per cent of Eastern Power's sales volumes were sold under contract and are expected to continue to be 100 per cent sold under contract for the remainder of 2011 and in 2012.

Bruce Power Results

(TCPL's proportionate share) *(unaudited)* *(millions of dollars unless otherwise indicated)*	Three months ended June 30 **2011**	 2010	Six months ended June 30 **2011**	 2010
Revenues[1]	**202**	197	**415**	422
Operating Expenses	**(146)**	(150)	**(282)**	(312)
Comparable EBITDA[2]	**56**	47	**133**	110
Bruce A Comparable EBITDA[2]	**32**	10	**66**	23
Bruce B Comparable EBITDA[2]	**24**	37	**67**	87
Comparable EBITDA[2]	**56**	47	**133**	110
Depreciation and amortization	**(28)**	(26)	**(56)**	(49)
Comparable EBIT[2]	**28**	21	**77**	61
Bruce Power – Other Information				
Plant availability				
Bruce A	**97%**	72%	**98%**	69%
Bruce B	**80%**	86%	**86%**	92%
Combined Bruce Power	**85%**	82%	**89%**	85%
Planned outage days				
Bruce A	**8**	25	**8**	60
Bruce B	**49**	47	**70**	47
Unplanned outage days				
Bruce A	**5**	22	**9**	48
Bruce B	**19**	-	**27**	6
Sales volumes (GWh)				
Bruce A	**1,436**	1,121	**2,936**	2,110
Bruce B	**1,760**	1,944	**3,792**	4,099
	3,196	3,065	**6,728**	6,209
Results per MWh				
Bruce A power revenues	**$66**	$65	**$66**	$64
Bruce B power revenues[3]	**$55**	$59	**$54**	$58
Combined Bruce Power revenues	**$59**	$60	**$58**	$60

(1) Revenues include Bruce A's fuel cost recoveries of $7 million and $15 million for the three and six months ended June 30, 2011, respectively (2010 – $9 million and $14 million).
(2) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(3) Includes revenues received under the floor price mechanism, from deemed generation, including the associated volumes, and from contract settlements.

TCPL's proportionate share of Bruce A's Comparable EBITDA for the three and six months ended June 30, 2011 of $32 million and $66 million, respectively, increased from $10 million and $23 million, respectively, in the same periods in 2010 as a result of higher volumes and lower operating expenses due to lower planned and unplanned outage days. Results for the six months ended June 30, 2010 included a payment made from Bruce B to Bruce A regarding 2009 amendments to a long-term agreement with the Ontario Power Authority (OPA). The net positive impact reflected TCPL's higher percentage ownership interest in Bruce A.

TCPL's proportionate share of Bruce B's Comparable EBITDA for the three and six months ended June 30, 2011 of $24 million and $67 million, respectively, decreased from $37 million and $87 million, respectively, in the same periods in 2010 primarily due to lower volumes and higher operating costs due to increased outage days, as well as lower realized prices resulting from the expiration of fixed-price contracts at higher prices. Results for the six months ended June 30, 2010 included the above-noted payment in first quarter 2010 to Bruce A.

Under a contract with the OPA, all output from Bruce A in second quarter 2011 was sold at a fixed price of $66.33 per MWh (before recovery of fuel costs from the OPA) compared to $64.71 per MWh in second quarter 2010. Also under a contract with the OPA, all output from the Bruce B units was subject to a floor price of $50.18 per MWh in second quarter 2011 compared to $48.96 per MWh in second quarter 2010. Both the Bruce A and Bruce B contract prices are adjusted annually for inflation on April 1.

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. With respect to 2011, TCPL currently expects spot prices to be less than the floor price for the remainder of the year, therefore no amounts recorded in revenues in the first six months of 2011 are expected to be repaid.

Bruce B 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 decreased to $55 per MWh and $54 per MWh for the three and six months ended June 30, 2011, respectively, a decrease of $4 per MWh from each of the same periods in 2010, and reflected revenues recognized from both the floor price mechanism and contract sales. The decreases were a result of the majority of higher-priced contracts entered into in previous years having expired by the end of December 2010. As the remainder of these higher-priced contracts continue to expire, a further reduction in realized prices at Bruce B in future periods is expected.

The overall plant availability percentage in 2011 is expected to be in the mid-80s for the two operating Bruce A units and in the mid-80s for the four Bruce B units. Bruce B commenced an approximately three week outage on Unit 6 in late July 2011. For further information on Bruce Power's planned maintenance outages, refer to the MD&A in TCPL's 2010 Annual Report.

As at June 30, 2011, Bruce A had incurred approximately $4.4 billion in costs for the refurbishment and restart of Units 1 and 2, and approximately $0.3 billion for the refurbishment of Units 3 and 4.

U.S. Power Comparable EBIT(1)(2)

(unaudited)	Three months ended June 30		Six months ended June 30	
(millions of U.S. dollars)	**2011**	2010	**2011**	2010
Revenues				
Power(3)	**224**	237	**479**	469
Capacity	**74**	66	**113**	106
Other(4)	**13**	15	**43**	40
	311	318	**635**	615
Commodity purchases resold	**(84)**	(112)	**(215)**	(248)
Plant operating costs and other(4)	**(128)**	(128)	**(250)**	(216)
General, administrative and support costs	**(10)**	(9)	**(19)**	(18)
Comparable EBITDA(1)	**89**	69	**151**	133
Depreciation and amortization	**(24)**	(27)	**(54)**	(52)
Comparable EBIT(1)	**65**	42	**97**	81

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.
(2) Includes phase two of Kibby Wind effective October 2010.
(3) The realized gains and losses from financial derivatives used to purchase and sell power, natural gas and fuel oil to manage U.S. Power's assets are presented on a net basis in Power Revenues.
(4) Includes revenues and costs related to a third-party service agreement at Ravenswood.

U.S. Power Operating Statistics[1]

(unaudited)	Three months ended June 30 2011	2010	Six months ended June 30 2011	2010
Physical Sales Volumes (GWh)				
Supply				
Generation	**1,941**	1,789	**3,232**	2,680
Purchased	**1,181**	2,061	**3,120**	4,547
	3,122	3,850	**6,352**	7,227
Plant Availability[2][3]	**86%**	92%	**84%**	89%

(1) Includes phase two of Kibby Wind effective October 2010.
(2) Plant availability represents the percentage of time in a period that the plant is available to generate power regardless of whether it is running.
(3) Plant availability decreased in the three and six months ended June 30, 2011 due to the impact of planned outages at Ravenswood and OSP.

U.S Power's Comparable EBITDA of US$89 million and US$151 million for the three and six months ended June 30, 2011, respectively, increased US$20 million and US$18 million, respectively, compared to the same periods in 2010. The increases were primarily due to increased capacity revenues, higher realized power prices and incremental earnings from phase two of Kibby Wind which went into service in October 2010.

U.S. Power's Power Revenues of US$224 for the three months ended June 30, 2011 decreased US$13 million compared to the same period in 2010, primarily due to lower physical volumes of power sold, partially offset by higher realized power prices, incremental revenues from the second phase of Kibby Wind, new sales activity in the PJM Interconnection area (PJM) and an increase in the New York commercial customer base. For the six months ended June 30, 2011, U.S. Power's Power Revenues were US$479 million, an increase of US$10 million from the same period in 2010 as a result of higher realized power prices, incremental revenues from the second phase of Kibby Wind and additional revenue from PJM and New York commercial customers, partially offset by lower volumes of power sold.

Capacity Revenues of US$74 million and US$113 million for the three and six months ended June 30, 2011, respectively, increased from US$66 million and US$106 million, respectively, in the same periods in 2010 primarily due to a reduction in forced outage rates at Ravenswood, partially offset by lower capacity prices in the New England power market.

Commodity Purchases Resold of US$84 million and US$215 million for the three and six months ended June 30, 2011, respectively, decreased from US$112 million and US$248 million, respectively, in the same periods in 2010 primarily due to a decrease in the quantity of power purchased for resale, partially offset by higher power prices per MWh purchased.

Plant Operating Costs and Other, including fuel gas consumed in generation, of US$128 million in second quarter 2011, was consistent with second quarter 2010. For the six months ended June 30, 2011, Plant Operating Costs and Other were US$250 million, an increase of US$34 million from the same period in 2010 primarily due to higher fuel costs as a result of increased generation, incremental operating costs from the second phase of Kibby Wind and reduced lease costs related to Ravenswood in 2010.

U.S. Power focuses on selling power under short- and long-term contracts to wholesale, commercial and industrial customers in the New England, New York and PJM power markets. Exposure to fluctuations in spot prices on these power sales commitments are hedged with a combination of forward purchases of power, forward purchases of fuel to generate power and through the use of financial contracts. As at June 30, 2011, approximately 3,100 GWh or 67 per cent of U.S. Power's planned generation is contracted for the remainder of 2011. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets, and power sales fluctuate based on customer usage. The seasonal nature of the U.S. Power business generally results in higher generation volumes in the summer months.

Natural Gas Storage

Natural Gas Storage's Comparable EBITDA for the three and six month periods ended June 30, 2011, was $18 million and $47 million, respectively, compared to $18 million and $69 million, respectively, for the same periods in 2010. The decrease in Comparable EBITDA in the six months ended June 30, 2011 compared to the same period in 2010 was primarily due to decreased proprietary and third-party storage revenues as a result of lower realized natural gas price spreads.

Other Income Statement Items

Comparable Interest Expense(1)

(unaudited) *(millions of dollars)*	Three months ended June 30 **2011**	2010	Six months ended June 30 **2011**	2010
Interest on long-term debt(2)				
Canadian dollar-denominated	**122**	129	**244**	260
U.S. dollar-denominated	**180**	163	**362**	322
Foreign exchange	**(5)**	5	**(8)**	11
	297	297	**598**	593
Other interest and amortization	**34**	44	**68**	76
Capitalized interest	**(68)**	(143)	**(165)**	(277)
Comparable Interest Expense(1)	**263**	198	**501**	392

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable Interest Expense.
(2) Includes interest on Junior Subordinated Notes.

Comparable Interest Expense for second quarter 2011 increased $65 million to $263 million from $198 million in second quarter 2010. Comparable Interest Expense for the six months ended June 30, 2011 increased $109 million to $501 million from $392 million for the six months ended June 30, 2010. The increases reflected lower capitalized interest for Keystone and Halton Hills as assets were placed into service, and incremental interest expense on debt issues of US$1.25 billion in June 2010 and US$1.0 billion in September 2010. These increases were partially offset by realized gains in 2011 compared to losses in 2010 from derivatives used to manage the Company's exposure to rising interest rates, the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest and Canadian dollar-denominated debt maturities in 2011 and 2010.

Comparable Interest Income and Other for second quarter 2011 increased $44 million to income of $26 million from an expense of $18 million in second quarter 2010. Comparable Interest Income and Other for the six months ended June 30, 2011 increased $51 million to income of $57 million from income of $6 million for the six months ended June 30, 2010. The increases reflected realized gains in 2011 compared to losses in 2010 on derivatives used to manage the Company's net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and from the translation of working capital balances due to a weakening of the U.S. dollar.

Comparable Income Taxes were $132 million in second quarter 2011 compared to $57 million for the same period in 2010. Comparable Income Taxes for the six months ended June 30, 2011 were $310 million compared to $171 million for the same period in 2010. The increases were primarily due to higher pre-tax earnings in 2011 compared to 2010 and higher positive income tax adjustments in 2010 compared to 2011.

Liquidity and Capital Resources

TCPL believes that its 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 provide for planned growth. TCPL's liquidity is underpinned by predictable cash flow from operations, cash balances on hand and unutilized committed revolving bank lines of US$1.0 billion, $2.0 billion, US$1.0 billion and US$200 million, maturing in November 2011, December 2012, December 2012 and February 2013, respectively. These facilities also support the Company's commercial paper programs. In addition, at June 30, 2011, TCPL's proportionate share of unutilized capacity on committed bank facilities at TCPL-operated affiliates was $169 million with maturity dates in 2011 and 2012. As at June 30, 2011, TCPL had remaining capacity of $2.0 billion and US$1.75 billion under its Canadian debt and U.S. debt shelf prospectuses, respectively. TCPL's liquidity, market and other risks are discussed further in the Risk Management and Financial Instruments section in this MD&A.

At June 30, 2011, the Company held Cash and Cash Equivalents of $455 million compared to $752 million at December 31, 2010. The decrease in Cash and Cash Equivalents was primarily due to expenditures for the Company's capital program, debt repayments and dividend payments, partially offset by increased cash generated from operations.

Operating Activities

Funds Generated from Operations[(1)]

(unaudited)	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2011**	2010	**2011**	2010
Cash Flows				
Funds generated from operations[(1)]	**869**	922	**1,764**	1,634
Decrease/(increase) in operating working capital	**26**	(316)	**136**	(200)
Net cash provided by operations	**895**	606	**1,900**	1,434

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

Net Cash Provided by Operations increased $289 million and $466 million for the three and six months ended June 30, 2011, respectively, compared to the same periods in 2010, largely as a result of changes in operating working capital. The six months ended June 30, 2011 also reflected an increase in Funds Generated from Operations. Funds Generated from Operations for the three and six months ended June 30, 2011 were $869 million and $1.8 billion, respectively, compared to $922 million and $1.6 billion, respectively, for the same periods in 2010. The decrease for the three months ended June 30, 2011 was primarily due to the second quarter 2010 income tax benefit generated from bonus depreciation for U.S. tax purposes on Keystone assets placed in service in June 2010. Cash generated through earnings increased in second quarter 2011 compared to second quarter 2010 excluding the 2010 income tax benefit from bonus depreciation. The increase for the six months ended June 30, 2011, was primarily due to an increase in cash generated through earnings, partially offset by the 2010 income tax benefit from bonus depreciation.

As at June 30, 2011, TCPL's current liabilities were $4.6 billion and current assets were $4.0 billion resulting in a working capital deficiency of $0.6 billion. Excluding $1.6 billion of Notes Payable under the Company's commercial paper programs and draws on its line-of-credit facilities, TCPL's working capital was $1.0 billion.

Investing Activities

TCPL remains committed to executing its remaining $11 billion capital expenditure program. For the three and six months ended June 30, 2011, capital expenditures totalled $0.7 billion and $1.4 billion, respectively (2010 – $1.0 billion and $2.3 billion, respectively), primarily related to the construction of Keystone, the refurbishment and restart of Bruce A Units 1 and 2, and expansion of the Alberta System.

Financing Activities

On July 13, 2011, PipeLines LP entered into a five-year, US$500 million senior syndicated revolving credit facility, maturing July 2016. The proceeds from the credit facility were used to reduce PipeLines LP's term loan and senior revolving credit facility, and repay its bridge loan facility. PipeLines LP's remaining US$300 million term loan matures December 2011.

In June 2011, TCPL retired $60 million of 9.5 per cent Medium-Term Notes and, in January 2011, retired $300 million of 4.3 per cent Medium-Term Notes.

In June 2011, PipeLines LP issued US$350 million of 4.65 per cent Senior Notes due 2021 and cancelled US$175 million of its unsecured syndicated senior credit facility.

In May 2011, PipeLines LP completed a public offering of 7,245,000 common units at a price of US$47.58 per unit, resulting in gross proceeds of approximately US$345 million. TCPL contributed an additional approximate US$7 million to maintain its general partnership interest and did not purchase any other units. Upon completion of this offering, TCPL's ownership interest in PipeLines LP decreased from 38.2 per cent to 33.3 per cent. In addition, PipeLines LP made draws of US$61 million on a bridge loan facility and of US$125 million on its senior revolving credit facility.

In June 2011, TCPL filed a $2.0 billion Canadian Medium-Term Notes base shelf prospectus to replace an April 2009 $2.0 billion Canadian Medium-Term Notes base shelf prospectus, which expired in May 2011 and had remaining capacity of $2.0 billion.

The Company believes it has the capacity to fund its existing capital program through internally-generated cash flow, continued access to capital markets and liquidity underpinned by in excess of $4 billion of committed credit facilities. TCPL's financial flexibility is further bolstered by opportunities for portfolio management, including an ongoing role for PipeLines LP.

Dividends

On July 28, 2011, TCPL's Board of Directors declared a quarterly dividend for the quarter ending September 30, 2011 in the aggregate amount equal to the quarterly dividend paid on TransCanada Corporation's (TransCanada) issued and outstanding common shares at the close of business on September 30, 2011. The dividend is payable on October 31, 2011. The Board of Directors also declared dividends of $0.70 per share for Series U and Series Y preferred shares for the period ending October 30, 2011 and November 1, 2011, respectively. The dividends are payable on October 31, 2011 and November 1, 2011, respectively to shareholders of record at the close of business on September 30, 2011.

Commencing with the dividends declared April 28, 2011, common shares purchased with reinvested cash dividends under TransCanada's Dividend Reinvestment and Share Purchase Plan (DRP) will no longer be satisfied with shares issued from treasury at a discount but rather will be acquired on the open market at 100 per cent of the weighted average purchase price. Under this Plan, eligible TCPL preferred shareholders may reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares.

Contractual Obligations

In the first six months of 2011, TCPL had a net reduction to its purchase obligations primarily due to the settlement of its commitments in the normal course of business. There have been no other material changes to TCPL's contractual obligations from December 31, 2010 to June 30, 2011, including payments due for the next five years and thereafter. For further information on these contractual obligations, refer to the MD&A in TCPL's 2010 Annual Report.

Significant Accounting Policies and Critical Accounting Estimates

To prepare financial statements that conform with GAAP, TCPL 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.

TCPL's significant accounting policies and critical accounting estimates have remained unchanged since December 31, 2010. For further information on the Company's accounting policies and estimates refer to the MD&A in TCPL's 2010 Annual Report.

Changes in Accounting Policies

The Company's accounting policies have not changed materially from those described in TCPL's 2010 Annual Report except as follows:

Changes in Accounting Policies for 2011

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests
Effective January 1, 2011, the Company adopted CICA Handbook Section 1582 "Business Combinations", which is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting the standard is expected to have a significant impact on the way the Company accounts for future business combinations. Entities adopting Section 1582 were also required to adopt CICA Handbook Sections 1601 "Consolidated Financial Statements" and 1602 "Non-Controlling Interests". Sections 1601 and 1602 require Non-Controlling Interests to be presented as part of Equity on the balance sheet. In addition, the income statement of the controlling parent now includes 100 per cent of the subsidiary's results and presents the allocation of income between the controlling and non-controlling interests. Changes resulting from the adoption of Section 1582 were applied prospectively and changes resulting from the adoption of Sections 1601 and 1602 were applied retrospectively.

Future Accounting Changes

U.S. GAAP/International Financial Reporting Standards
The CICA's 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.

In accordance with GAAP, TCPL follows specific accounting policies unique to a rate-regulated business. These rate-regulated accounting (RRA) standards allow the timing of recognition of certain revenues and expenses to differ from the timing that may otherwise be expected in a non-rate-regulated business under GAAP in order to appropriately reflect the economic impact of regulators' decisions regarding the Company's revenues and tolls.

In July 2009, the IASB issued an Exposure Draft "Rate-Regulated Activities", which proposed a form of RRA under IFRS. At its September 2010 meeting, the IASB concluded that the development of RRA under IFRS requires further analysis and removed the RRA project from its current agenda. TCPL does not expect a final RRA standard under IFRS to be effective in the foreseeable future.

In October 2010, the AcSB and the Canadian Securities Administrators amended their policies applicable to Canadian publicly accountable enterprises that use RRA in order to permit these entities to defer the adoption of IFRS for one year. TCPL deferred its adoption and accordingly will continue to prepare its consolidated financial statements in 2011 in accordance with Canadian GAAP, as defined by Part V of the CICA Handbook, in order to continue using RRA.

As an SEC registrant, TCPL prepares and files a "Reconciliation to United States GAAP" and has the option to prepare and file its consolidated financial statements using U.S. GAAP. As a result of the developments noted above, the Company's Board of Directors has approved the adoption of U.S. GAAP effective January 1, 2012.

U.S. GAAP Conversion Project

Effective January 1, 2012, the Company will begin reporting using U.S. GAAP. TCPL's IFRS conversion team has been redeployed to support the conversion to U.S. GAAP. The conversion team is led by a multi-disciplinary Steering Committee that provides directional leadership for the adoption of U.S. GAAP. Management also updates TCPL's Audit Committee on the progress of the U.S. GAAP project at each Audit Committee meeting and reports regularly to the Company's Board of Directors on the status of the conversion project.

U.S. GAAP training sessions continue for TCPL staff who are impacted by the conversion and will be ongoing as needed throughout 2011. Significant changes to existing systems and processes are not required to implement U.S. GAAP as the Company's primary accounting standard since TCPL prepares and files a "Reconciliation to United States GAAP". The impact to internal controls over financial reporting and disclosure controls and procedures will be addressed over the remainder of 2011.

Identified differences between Canadian GAAP and U.S. GAAP that are significant to the Company are explained below and are consistent with those currently reported in the Company's publicly-filed "Reconciliation to United States GAAP."

Joint Ventures

Canadian GAAP requires the Company to account for certain investments using the proportionate consolidation method of accounting whereby TCPL's proportionate share of assets, liabilities, revenues, expenses and cash flows are included in the Company's financial statements. U.S. GAAP does not permit the use of proportionate consolidation with respect to TCPL's joint ventures and requires that such investments be recorded using the equity method of accounting.

Inventory

Canadian GAAP allows the Company's proprietary natural gas inventory held in storage to be recorded at its fair value. Under U.S. GAAP, inventory is recorded at the lower of cost or market.

Income Tax

Canadian GAAP requires an entity to record income tax assets and liabilities resulting from substantively enacted income tax legislation. Under U.S. GAAP, the legislation must be fully enacted for income tax adjustments to be recorded.

Employee Benefits

Canadian GAAP requires an entity to recognize an accrued benefit asset or liability for defined benefit pension and other postretirement benefit plans. Under U.S. GAAP, an employer is required to recognize the overfunded or underfunded status of defined benefit pension and other postretirement benefit plans as an asset or liability in its balance sheet and to recognize changes in the funded status through Other Comprehensive Income in the year in which the change occurs.

Debt Issue Costs
Canadian GAAP requires debt issue costs to be included in long-term debt. Under U.S. GAAP these costs are classified as deferred assets.

Financial Instruments and Risk Management

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

Counterparty Credit and Liquidity Risk

TCPL's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date, without taking into account security held, consisted of accounts receivable, portfolio investments recorded at fair value, the fair value of derivative assets, and notes, loans and advances receivable. The carrying amounts and fair values of these financial assets, except amounts for derivative assets, are included in Accounts Receivable and Other, and Available-For-Sale Assets in the Non-Derivative Financial Instruments Summary table below. Guarantees, 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, 2011, there were no significant amounts past due or impaired.

At June 30, 2011, the Company had a credit risk concentration of $286 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 Storage Commodity Price Risk

At June 30, 2011, 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 $47 million (December 31, 2010 - $49 million). The change in the fair value adjustment of proprietary natural gas inventory in storage in the three and six months ended June 30, 2011 resulted in net pre-tax unrealized losses of $1 million and gains of $1 million, respectively (2010 – gains of $4 million and losses of $20 million, respectively), which were recorded as adjustments to Revenues and Inventories. The change in fair value of natural gas forward purchase and sale contracts in the three and six months ended June 30, 2011 resulted in net pre-tax unrealized losses of $3 million and $10 million, respectively (2010 – gains of $2 million and $5 million, respectively), which were included in Revenues.

VaR Analysis

TCPL uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its liquid open 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. TCPL's consolidated VaR was $11 million at June 30, 2011, which was consistent with VaR at December 31, 2010 of $12 million.

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, 2011, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $9.5 billion (US$9.8 billion) and a fair value of $10.8 billion (US$11.2 billion). At June 30, 2011, $279 million (December 31, 2010 - $181 million) was included in Other Current Assets and 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) *(unaudited)* *(millions of dollars)*	**June 30, 2011** Fair Value[1]	**June 30, 2011** Notional or Principal Amount	December 31, 2010 Fair Value[1]	December 31, 2010 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2011 to 2018)	**276**	**US 3,550**	179	US 2,800
U.S. dollar forward foreign exchange contracts (maturing 2011)	**3**	**US 600**	2	US 100
	279	**US 4,150**	181	US 2,900

(1) Fair values equal carrying values.

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

Non-Derivative Financial Instruments Summary

(unaudited) *(millions of dollars)*	**June 30, 2011** Carrying Amount	**June 30, 2011** Fair Value	December 31, 2010 Carrying Amount	December 31, 2010 Fair Value
Financial Assets[1]				
Cash and cash equivalents	**455**	**455**	752	752
Accounts receivable and other[2][3]	**1,502**	**1,534**	1,564	1,604
Due from TransCanada Corporation	**1,249**	**1,249**	1,363	1,363
Available-for-sale assets[2]	**22**	**22**	20	20
	3,228	**3,260**	3,699	3,739
Financial Liabilities[1][3]				
Notes payable	**1,628**	**1,628**	2,092	2,092
Accounts payable and deferred amounts[4]	**1,059**	**1,059**	1,444	1,444
Due to TransCanada Corporation	**2,796**	**2,796**	2,703	2,703
Accrued interest	**403**	**403**	361	361
Long-term debt	**17,340**	**20,498**	17,922	21,523
Long-term debt of joint ventures	**839**	**946**	866	971
Junior subordinated notes	**955**	**962**	985	992
	25,020	**28,292**	26,373	30,086

(1) Consolidated Net Income in the three and six months ended June 30, 2011 included losses of $2 million and $11 million, respectively, (2010 – losses of $2 million and $9 million, respectively), for fair value adjustments related to interest rate swap agreements on US$350 million (2010 – US$150 million) of Long-Term Debt. There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

(2) At June 30, 2011, the Consolidated Balance Sheet included financial assets of $1,181 million (December 31, 2010 – $1,280 million) in Accounts Receivable, $38 million (December 31, 2010 – $40 million) in Other Current Assets and $305 million (December 31, 2010 - $264 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost, except for the US$350 million (December 31, 2010 – US$250 million) of Long-Term Debt that is adjusted to fair value.

(4) At June 30, 2011, the Consolidated Balance Sheet included financial liabilities of $1,024 million (December 31, 2010 – $1,414 million) in Accounts Payable and $35 million (December 31, 2010 - $30 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, 2011 *(unaudited)* *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	**$149**	**$118**	**$6**	**$18**
Liabilities	**$(114)**	**$(146)**	**$(15)**	**$(19)**
Notional Values				
Volumes[3]				
Purchases	**21,569**	**155**	**-**	**-**
Sales	**23,961**	**123**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**634**
U.S. dollars	**-**	**-**	**US 1,622**	**US 250**
Cross-currency	**-**	**-**	**47/US 37**	**-**
Net unrealized gains/(losses) in the period[4]				
Three months ended June 30, 2011	**$4**	**$(9)**	**$(2)**	**$1**
Six months ended June 30, 2011	**$3**	**$(26)**	**$-**	**$-**
Net realized gains/(losses) in the period[4]				
Three months ended June 30, 2011	**$8**	**$(15)**	**$12**	**$3**
Six months ended June 30, 2011	**$11**	**$(41)**	**$33**	**$5**
Maturity dates	**2011-2018**	**2011-2016**	**2011-2012**	**2012-2016**
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	**$57**	**$5**	**$-**	**$11**
Liabilities	**$(197)**	**$(17)**	**$(56)**	**$(14)**
Notional Values				
Volumes[3]				
Purchases	**18,524**	**14**	**-**	**-**
Sales	**9,187**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**US 120**	**US 1,000**
Cross-currency	**-**	**-**	**136/US 100**	**-**
Net realized losses in the period[4]				
Three months ended June 30, 2011	**$(8)**	**$(5)**	**$-**	**$(4)**
Six months ended June 30, 2011	**$(46)**	**$(8)**	**$-**	**$(9)**
Maturity dates	**2011-2017**	**2011-2013**	**2011- 2014**	**2011-2015**

(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 Bcf, respectively.

(4) Realized and unrealized gains and losses on held-for-trading derivative financial instruments used to purchase and sell power and natural gas are included on a net basis 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 cash flow hedging relationships is initially recognized in Other Comprehensive Income and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $11 million and a notional amount of US$350 million at June 30, 2011. Net realized gains on fair value hedges for the three and six months ended June 30, 2011 were $2 million and $4 million, respectively, and were included in Interest Expense. In the three and six months ended June 30, 2011, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) For the three and six months ended June 30, 2011, Net Income included gains of $2 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. For the three and six months ended June 30, 2011, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

2010 *(unaudited)* *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading				
Fair Values[(1) (2)]				
Assets	$169	$144	$8	$20
Liabilities	$(129)	$(173)	$(14)	$(21)
Notional Values[(2)]				
Volumes[(3)]				
Purchases	15,610	158	-	-
Sales	18,114	96	-	-
Canadian dollars	-	-	-	736
U.S. dollars	-	-	US 1,479	US 250
Cross-currency	-	-	47/US 37	-
Net unrealized (losses)/gains in the period[(4)]				
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[(4)]				
Three months ended June 30, 2010	$15	$(17)	$(6)	$(6)
Six months ended June 30, 2010	$37	$(29)	$2	$(10)
Maturity dates[(2)]	2011-2015	2011-2015	2011-2012	2011-2016
Derivative Financial Instruments in Hedging Relationships[(5)(6)]				
Fair Values[(1)(2)]				
Assets	$112	$5	$-	$8
Liabilities	$(186)	$(19)	$(51)	$(26)
Notional Values[(2)]				
Volumes[(3)]				
Purchases	16,071	17	-	-
Sales	10,498	-	-	-
U.S. dollars	-	-	US 120	US 1,125
Cross-currency	-	-	136/US 100	-
Net realized losses in the period[(4)]				
Three months ended June 30, 2010	$(36)	$(6)	$-	$(9)
Six months ended June 30, 2010	$(43)	$(9)	$-	$(19)
Maturity dates[(2)]	2011-2015	2011-2013	2011-2014	2011-2015

(1) Fair values equal carrying values.

(2) As at December 31, 2010.

(3) Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

(4) Realized and unrealized gains and losses on held-for-trading derivative financial instruments used to purchase and sell power and natural gas are included on a net basis 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 cash flow hedging relationships is initially recognized in Other Comprehensive Income and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $8 million and a notional amount of US$250 million at December 31, 2010. 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 the three and six months ended June 30, 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) For the three and six months ended June 30, 2010, Net Income 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. For the three and six months ended June 30, 2010, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts were 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:

(unaudited) *(millions of dollars)*	**June 30, 2011**	December 31, 2010
Current		
Other current assets	**299**	273
Accounts payable	**(314)**	(337)
Long-term		
Intangibles and other assets	**344**	374
Deferred amounts	**(264)**	(282)

Other Risks

Additional risks faced by the Company are discussed in the MD&A in TCPL's 2010 Annual Report. These risks remain substantially unchanged since December 31, 2010.

Controls and Procedures

As of June 30, 2011, 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 TCPL'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 TCPL's disclosure controls and procedures were effective at a reasonable assurance level as at June 30, 2011.

During the quarter ended June 30, 2011, there have been no changes in TCPL's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, TCPL's internal control over financial reporting.

Outlook

Since the disclosure in TCPL's 2010 Annual Report, the Company's overall earnings outlook for 2011 has improved due to higher realized power prices in Western Power in the first half of 2011, with relatively strong prices expected throughout the remainder of 2011. The Company's earnings outlook could also be affected by the uncertainty and ultimate resolution of the capacity pricing issues in New York, as discussed in the Recent Developments section of this MD&A. For further information on outlook, refer to the MD&A in TCPL's 2010 Annual Report.

Recent Developments

Natural Gas Pipelines

Canadian Mainline

2011 Final Tolls
In April 2011, TCPL filed an application with the NEB for approval of Canadian Mainline's final tolls for 2011 determined in accordance with the existing 2007-2011 Tolls Settlement.

TCPL proposed to continue charging the interim 2011 tolls for the remainder of 2011 and to carry forward to 2012 the difference between the revenue that would have been generated from the final tolls and the revenue actually generated from the interim tolls. The interim 2011 tolls were implemented on March 1, 2011 and reflected a firm transportation toll from Empress, Saskatchewan to Dawn, Ontario of $1.89 per gigajoule. Adjusting for the difference in 2012 will result in greater Canadian Mainline toll certainty and stability.

In May 2011, the NEB solicited comments on the application for final tolls from interested parties, requesting their position and recommended process with respect to the application. Subsequently, the NEB solicited additional comments on the application and required TCPL to file a reply submission by July 29, 2011.

2012 – 2013 Tolls Application

As part of its 2011 final tolls application, TCPL informed the NEB of its intent to file an application for 2012 and 2013 tolls by October 31, 2011 that will include changes to the business structure, toll design and services. These changes are intended to improve the competitiveness of TCPL's regulated Canadian natural gas transportation infrastructure and the Western Canada Sedimentary Basin (WCSB).

In June, 2011, the NEB directed TCPL to file the 2012 and 2013 tolls application by September 1, 2011. TCPL will comply with the NEB's direction, however, certain elements of the application which cannot be available on September 1, 2011 will be filed by the end of October 2011.

Marcellus Facilities Expansion

The Company has concluded new capacity open seasons for the Canadian Mainline that resulted in contractual agreements to transport a total of approximately 350 million cubic feet per day (mmcf/d) of Marcellus shale gas to eastern markets for deliveries that are expected to commence in 2012 and 2013. An application for approval to construct approximately $130 million of new facilities required to provide this service was filed with the NEB on July 18, 2011.

Ongoing shipper interest is expected to result in additional requests for new capacity on the eastern part of the Canadian Mainline over time.

Alberta System

The Alberta System continues to operate under 2011 interim tolls approved by the NEB in 2010. In May 2011, TCPL filed for final 2011 tolls that reflect the provisions of the Alberta System 2010 – 2012 Revenue Requirement Settlement and commercial integration of the ATCO Pipelines system.

The Alberta System's Horn River natural gas pipeline project was approved by the NEB in January 2011 and commenced construction in March 2011, with a targeted completion date of second quarter 2012 and an estimated capital cost of $275 million. In addition, the Company has executed an agreement to extend the Horn River pipeline by approximately 100 kilometres (km) (62 miles) at an estimated capital cost of $230 million. As a result of the extension, additional contractual commitments of 100 mmcf/d are expected to commence in 2014 with volumes increasing to 300 mmcf/d by 2020. The total contracted volumes for Horn River, including the extension, are expected to be approximately 900 mmcf/d in 2020.

On June 24, 2011, the NEB approved the construction and operation of a 24 km (15 miles) extension of the Groundbirch natural gas pipeline. Construction is expected to commence in August 2011 with an in-service date of April 1, 2012 and an estimated capital cost of approximately $60 million. The project is required to service 250 mmcf/d of new transportation contracts.

TCPL continues to advance further pipeline development in British Columbia (B.C.) and Alberta to transport new natural gas supplies. The Company has filed several applications with the NEB requesting approval of further expansions of the Alberta System to accommodate requests for additional natural gas transmission service throughout the northwest portion of the WCSB. As at June 30, 2011, in addition to the projects previously discussed, the NEB had approved natural gas pipeline projects with capital costs of approximately $500 million. Further pipeline projects with a total capital cost of approximately $700 million at June 30, 2011 are awaiting NEB approval.

The successful Canadian Mainline open seasons and ongoing business with Western Canadian producers have resulted in new contracts from both the Montney and Horn River shale gas formations. Including the projects discussed above, TCPL has firm commitments to transport 2.9 Bcf/d from northwest Alberta and northeast B.C. by 2014. Further requests for significant additional volumes on the Alberta System from the northwest portion of the WCSB have been received.

Guadalajara

TCPL's US$360 million, 307 km (191 miles) Guadalajara natural gas pipeline went into service on June 15, 2011. All of the pipeline's utilized capacity is under a 25-year contract with Comisión Federal de Electricidad (CFE), Mexico's state-owned electric company. TCPL and the CFE have agreed to add a US$60 million compressor station to the pipeline that is expected to be operational early in 2013.

PipeLines LP

On May 3, 2011, the Company completed the sale of a 25 per cent interest in each of Gas Transmission Northwest LLC (GTN LLC) and Bison Pipeline LLC (Bison LLC) to PipeLines LP for an aggregate purchase price of US$605 million, subject to closing adjustments, which included US$81 million of long-term debt, or 25 per cent of GTN LLC debt outstanding. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively.

On May 3, 2011, PipeLines LP completed an underwritten public offering of 7,245,000 common units, including 945,000 common units purchased by the underwriters upon full exercise of an over-allotment option, at US$47.58 per unit. Gross proceeds of approximately US$345 million from this offering were used to partially fund the acquisition. The acquisition was also funded by draws of US$61 million on PipeLines LP's bridge loan facility and of US$125 million on its US$250 million senior revolving credit facility.

As part of this offering, TCPL made a capital contribution of approximately US$7 million to maintain its two per cent general partnership interest in PipeLines LP and did not purchase any other units. As a result of the common units offering, TCPL's ownership in PipeLines LP decreased from 38.2 per cent to 33.3 per cent and an after-tax dilution gain of $30 million ($50 million pre-tax) was recorded in Contributed Surplus.

Oil Pipelines

Keystone

On May 1, 2011, revised fixed tolls came into effect for the Wood River/Patoka section of the system. These revised tolls reflect the final project costs of the Wood River/Patoka section of Keystone.

Keystone experienced two above-ground incidents in second quarter 2011, both of which involved the release of small amounts of crude oil at pump stations in North Dakota and Kansas. In each instance, Keystone's monitoring system worked as designed, allowing for the entire system to be shut down within minutes. As a result of these incidents, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a corrective action order on June 3, 2011 which required TCPL to develop and submit a written re-start plan prior to resuming operation of the pipeline. TCPL's re-start plan, which included steps to facilitate the proper clean-up, investigation, and system improvements and modifications, was approved by PHMSA on June 4, 2011. As a result of these shut downs, Keystone was not able to transport all of the shippers' nominated volumes in May and June 2011, however, the impact to EBITDA was not significant. TCPL remains committed to building and operating a safe, reliable pipeline. Additional work to improve and modify the system will continue into July and August 2011, which will result in a reduction in available pipeline capacity of approximately 20 per cent in each month. The impact to EBITDA is not expected to be significant.

TCPL's Keystone U.S. Gulf Coast Expansion (Keystone XL) is now entering the final stages of regulatory review. On April 15, 2011, the U.S. Department of State (DOS), the lead agency for U.S. federal regulatory approvals, issued a Supplemental Draft Environmental Impact Statement (SDEIS) in response to comments received on a Draft Environmental Impact Statement (DEIS) issued in April 2010 and to address new and additional information received. The SDEIS provided additional information on key environmental issues, but did not change the conclusion reached in the DEIS that the project would enhance U.S. energy security, benefit the U.S. economy and have limited environmental impact. A 45-day comment period on the SDEIS concluded June 6, 2011. The DOS is processing the comments and has announced its plans to issue a Final Environmental Impact Statement (FEIS) in third quarter 2011. Following the publication of an FEIS, the DOS will consult with other U.S. federal agencies during a 90-day period to determine if granting approval for Keystone XL is in the U.S. national interest. The DOS has indicated it will make a final decision regarding the Presidential Permit prior to the end of 2011.

The capital cost of Keystone, including Keystone XL, is estimated to be US$13 billion. At June 30, 2011, US$7.9 billion had been invested, including US$1.7 billion related to Keystone XL. The remainder is expected to be invested between now and the in-service date of the expansion, which is expected in 2013. Capital costs related to the construction of Keystone are subject to capital cost risk- and reward-sharing mechanisms with Keystone's long-term committed shippers.

Energy

Coolidge

The US$500 million Coolidge generating station went into service on May 1, 2011. Power from the 575 MW simple-cycle, natural gas-fired peaking facility located near Phoenix, Arizona is sold to the Salt River Project Agricultural Improvement and Power District under a 20-year PPA.

Sundance A

The binding arbitration process to resolve the Sundance A PPA dispute arising out of TransAlta Corporation's claims of force majeure and economic destruction has commenced. The arbitration panel is expected to hold a hearing in March and April 2012 for these claims. Assuming the hearing concludes within the time allotted, TCPL expects to receive a decision in mid-2012. As the limited information received by TCPL to date does not support these claims, TCPL continues to record revenues and costs under the PPA as though this event was a normal plant outage.

Ravenswood

The July 2011 spot price for capacity sales in the New York Zone J market has settled at materially lower levels than prior periods resulting from the manner in which the New York Independent System Operator (NYISO) has treated price mitigation for a new power plant that recently began service in this market. TCPL believes that this treatment by the NYISO is in direct contravention of a series of Federal Energy Regulatory Commission (FERC) orders which direct how new entrant capacity is to be treated for the purpose of determining capacity price. TCPL and a number of other parties have filed a series of complaints with the FERC. The outcome of the complaints and the long-term impact that this development may have on TCPL's Ravenswood operations are unknown.

The demand curve reset process continues with the NYISO's June 20, 2011 compliance filing resulting in an increased demand curve for 2011 to 2014. The FERC has not yet responded to this filing and, as a result, it is not yet known when the revised demand curves will be effective.

Bruce Power

Loading of fuel commenced on the refurbished Bruce A Unit 2 in second quarter 2011 and was completed in July. Fuel channel assembly was completed on Unit 1 during second quarter 2011, which was the final stage of Atomic Energy of Canada Limited's work on the reactors. Demobilization of refurbishment activity continues as the work transitions from construction to commissioning.

Subject to regulatory approval, Bruce Power expects to achieve a first synchronization of the Unit 2 generator to the electrical grid by the end of 2011, with commercial operation expected to occur in first quarter 2012. Bruce Power expects to load fuel into Unit 1 in third quarter 2011, with a first synchronization of the generator during first quarter 2012 and commercial operation is expected to occur during third quarter 2012. TCPL's share of the total capital cost is expected to be approximately $2.4 billion, of which $2.1 billion was incurred as of June 30, 2011.

Bécancour

In June 2011, Hydro-Québec notified TCPL it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant throughout 2012. 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. TCPL will continue to receive payments under the agreement similar to those that would have been received under the normal course of operation.

Oakville

In October 2010, the Government of Ontario announced that it would not proceed with the $1.2 billion Oakville generating station. The Company continues to negotiate a settlement with the Ontario government and its agencies that would terminate the 20-year Clean Energy Supply contract TCPL had previously been awarded and would compensate TCPL for the economic consequences associated with the contract's termination.

Zephyr

In June 2011, Zephyr terminated the precedent agreements with its potential shippers as the parties were unable to resolve key commercial issues. In July 2011, one of Zephyr's potential shippers exercised its contractual rights to acquire 100 per cent of the Zephyr project from TCPL.

Cartier Wind

Construction continues on the five-stage, 590 MW Cartier Wind project in Québec. The 58 MW Montagne-Sèche project and the 101 MW first phase of the Gros-Morne wind farm are expected to be operational in December 2011. The 111 MW Gros-Morne phase two is expected to be operational in December 2012. These are the fourth and fifth Québec-based wind farms of Cartier Wind, which are 62 per cent owned by TCPL. All of the power produced by Cartier Wind is sold under a 20-year PPA to Hydro-Québec.

Share Information

At July 25, 2011, TCPL had 675 common shares, four million Series U and four million Series Y preferred shares issued and outstanding.

Selected Quarterly Consolidated Financial Data[1]

(unaudited)	**2011**		2010				2009	
(millions of dollars)	**Second**	**First**	Fourth	Third	Second	First	Fourth	Third
Revenues	**2,143**	**2,243**	2,057	2,129	1,923	1,955	1,986	2,049
Net income attributable to controlling interests	**353**	**414**	276	387	292	301	384	343
Share Statistics								
Net income per common share – Basic and Diluted	**$0.51**	**$0.60**	$0.40	$0.57	$0.43	$0.46	$0.58	$0.55

(1) The selected quarterly consolidated financial data has been prepared in accordance with Canadian GAAP and is presented in Canadian dollars.

Factors Affecting Quarterly Financial Information

In Natural Gas Pipelines, which consists primarily of the Company's investments in regulated natural gas pipelines and regulated natural gas storage facilities, annual revenues, EBIT 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 Oil Pipelines, which consists of the Company’s investment in the Keystone crude oil pipeline, annual revenues are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues, EBIT and net income during any particular fiscal year remain relatively stable with fluctuations resulting from planned and unplanned outages, and changes in the amount of spot volumes transported and the associated rate charged. Spot volumes transported are affected by customer demand, market pricing, planned and unplanned outages of refineries, terminals and pipeline facilities, 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, EBIT 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 affected the last eight quarters' EBIT and Net Income are as follows:

- Second Quarter 2011, Natural Gas Pipelines’ EBIT included incremental earnings from Guadalajara, which was placed in service in June 2011. Energy’s EBIT included incremental earnings from Coolidge, which was placed in service in May 2011. EBIT included net unrealized losses of $5 million pre-tax ($4 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

- First Quarter 2011, Natural Gas Pipelines’ EBIT included incremental earnings from Bison, which was placed in service in January 2011. Oil Pipelines began recording EBIT for the Wood

River/Patoka and Cushing Extension sections of Keystone in February 2011. EBIT included net unrealized losses of $17 million pre-tax ($10 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

- Fourth Quarter 2010, Natural Gas Pipelines' EBIT decreased as a result of recording a $146 million pre-tax ($127 million after-tax) valuation provision for advances to the APG for the MGP. Energy's EBIT included contributions from the second phase of Kibby Wind, which was placed in service in October 2010, and net unrealized gains of $22 million pre-tax ($12 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

- Third Quarter 2010, Natural Gas Pipelines' EBIT increased as a result of recording nine months of incremental earnings related to the Alberta System 2010 – 2012 Revenue Requirement Settlement, which resulted in a $33 million increase to Net Income. Energy's EBIT included contributions from Halton Hills, which was placed in service in September 2010, and net unrealized gains of $4 million pre-tax ($3 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

- Second Quarter 2010, Energy's EBIT included net unrealized gains of $15 million pre-tax ($10 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. Net Income reflected a decrease of $58 million after tax due to 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 U.S. dollar-denominated working capital balances.

- First Quarter 2010, Energy's EBIT included net unrealized losses of $49 million pre-tax ($32 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

- Fourth Quarter 2009, Natural Gas Pipelines EBIT included a dilution gain of $29 million pre-tax ($18 million after tax) resulting from TCPL's reduced ownership interest in PipeLines LP, which was caused by PipeLines LP's issue of common units to the public. Energy's EBIT included net unrealized gains of $7 million pre-tax ($5 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. 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 certain risk management activities.

Consolidated Income

(unaudited) *(millions of dollars)*	Three months ended June 30 **2011**	2010	Six months ended June 30 **2011**	2010
Revenues	**2,143**	1,923	**4,386**	3,878
Operating and Other Expenses				
Plant operating costs and other	**822**	764	**1,581**	1,511
Commodity purchases resold	**185**	216	**462**	472
Depreciation and amortization	**379**	341	**749**	684
	1,386	1,321	**2,792**	2,667
Financial Charges/(Income)				
Interest expense	**262**	198	**501**	392
Interest expense of joint ventures	**11**	15	**27**	31
Interest income and other	**(23)**	18	**(56)**	(6)
	250	231	**472**	417
Income before Income Taxes	**507**	371	**1,122**	794
Income Taxes Expense				
Current	**38**	(198)	**138**	(118)
Future	**93**	260	**164**	277
	131	62	**302**	159
Net Income	**376**	309	**820**	635
Net Income Attributable to Non-Controlling Interests	**23**	17	**53**	42
Net Income Attributable to Controlling Interests	**353**	292	**767**	593
Preferred Share Dividends	**5**	5	**11**	11
Net Income Attributable to Common Shares	**348**	287	**756**	582

See accompanying notes to the consolidated financial statements.

Consolidated Comprehensive Income

(unaudited) *(millions of dollars)*	Three months ended June 30 **2011**	 2010	Six months ended June 30 **2011**	 2010
Net Income	**376**	309	**820**	635
Other Comprehensive (Loss)/Income, Net of Income Taxes				
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**(30)**	227	**(128)**	80
Change in gains and losses on financial derivatives to hedge the net investments in foreign operations[2]	**23**	(79)	**72**	(20)
Change in gains and losses on derivative instruments designated as cash flow hedges[3]	**(41)**	(44)	**(92)**	(120)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[4]	**18**	(5)	**62**	(6)
Other Comprehensive (Loss)/Income	**(30)**	99	**(86)**	(66)
Comprehensive Income	**346**	408	**734**	569
Comprehensive Income Attributable to Non-Controlling Interests	**28**	15	**61**	39
Comprehensive Income Attributable to Controlling Interests	**318**	393	**673**	530
Preferred Share Dividends	**5**	5	**11**	11
Comprehensive Income Attributable to Common Shares	**313**	388	**662**	519

(1) Net of income tax expense of $11 million and $40 million for the three and six months ended June 30, 2011, respectively (2010 – recovery of $45 million and $15 million, respectively).

(2) Net of income tax expense of $8 million and $27 million for the three and six months ended June 30, 2011, respectively (2010 – recovery of $34 million and $8 million, respectively).

(3) Net of income tax recovery of $21 million and $39 million for the three and six months ended June 30, 2011, respectively (2010 – recovery of $27 million and $84 million, respectively).

(4) Net of income tax expense of $10 million and $34 million for the three and six months ended June 30, 2011, respectively (2010 – expense of $16 million and $17 million, respectively).

See accompanying notes to the consolidated financial statements.

Consolidated Cash Flows

(unaudited) *(millions of dollars)*	Three months ended June 30 2011	2010	Six months ended June 30 2011	2010
Cash Generated From Operations				
Net income	**376**	309	**820**	635
Depreciation and amortization	**379**	341	**749**	684
Future income taxes	**93**	260	**164**	277
Employee future benefits funding less than/ (in excess of) expense	**3**	(12)	**(8)**	(44)
Other	**18**	24	**39**	82
	869	922	**1,764**	1,634
Decrease/(increase) in operating working capital	**26**	(316)	**136**	(200)
Net cash provided by operations	**895**	606	**1,900**	1,434
Investing Activities				
Capital expenditures	**(655)**	(992)	**(1,439)**	(2,268)
Deferred amounts and other	**5**	8	**10**	(208)
Net cash used in investing activities	**(650)**	(984)	**(1,429)**	(2,476)
Financing Activities				
Dividends on common and preferred shares	**(298)**	(280)	**(583)**	(546)
Advances from parent	**123**	15	**207**	398
Distributions paid to non-controlling interests	**(22)**	(23)	**(43)**	(44)
Notes payable repaid, net	**(548)**	(441)	**(415)**	(9)
Long-term debt issued, net of issue costs	**519**	1,306	**519**	1,316
Reduction of long-term debt	**(419)**	(142)	**(740)**	(283)
Long-term debt of joint ventures issued	**31**	70	**31**	78
Reduction of long-term debt of joint ventures	**(38)**	(113)	**(49)**	(139)
Common shares issued	**-**	402	**-**	402
Partnership units of subsidiary issued, net of issue costs	**321**	-	**321**	-
Net cash (used in)/provided by financing activities	**(331)**	794	**(752)**	1,173
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(3)**	33	**(16)**	16
(Decrease)/Increase in Cash and Cash Equivalents	**(89)**	449	**(297)**	147
Cash and Cash Equivalents				
Beginning of period	**544**	677	**752**	979
Cash and Cash Equivalents				
End of period	**455**	1,126	**455**	1,126
Supplementary Cash Flow Information				
Income taxes (refunded)/paid, including refunds	**(47)**	39	**40**	43
Interest paid	**242**	129	**504**	372

See accompanying notes to the consolidated financial statements.

Consolidated Balance Sheet

(unaudited) *(millions of dollars)*	**June 30, 2011**	December 31, 2010
ASSETS		
Current Assets		
Cash and cash equivalents	**455**	752
Accounts receivable	**1,181**	1,280
Due from TransCanada Corporation	**1,249**	1,363
Inventories	**427**	425
Other	**692**	777
	4,004	4,597
Plant, Property and Equipment	**36,234**	36,244
Goodwill	**3,461**	3,570
Regulatory Assets	**1,449**	1,512
Intangibles and Other Assets	**1,989**	2,026
	47,137	47,949
LIABILITIES		
Current Liabilities		
Notes payable	**1,628**	2,092
Accounts payable	**1,867**	2,247
Accrued interest	**403**	361
Current portion of long-term debt	**537**	894
Current portion of long-term debt of joint ventures	**159**	65
	4,594	5,659
Due to TransCanada Corporation	**2,796**	2,703
Regulatory Liabilities	**340**	314
Deferred Amounts	**710**	694
Future Income Taxes	**3,380**	3,250
Long-Term Debt	**16,803**	17,028
Long-Term Debt of Joint Ventures	**680**	801
Junior Subordinated Notes	**955**	985
	30,258	31,434
EQUITY		
Controlling interests	**15,852**	15,747
Non-controlling interests	**1,027**	768
	16,879	16,515
	47,137	47,949

See accompanying notes to the consolidated financial statements.

Consolidated Accumulated Other Comprehensive (Loss)/Income

(unaudited) *(millions of dollars)*	Currency Translation Adjustments	Cash Flow Hedges and Other	Total
Balance at December 31, 2010	**(683)**	**(194)**	**(877)**
Change in foreign currency translation gains and losses on investments in foreign operations(1)	**(128)**	**-**	**(128)**
Change in gains and losses on financial derivatives to hedge the net investments in foreign operations(2)	**72**	**-**	**72**
Change in gains and losses on derivative instruments designated as cash flow hedges(3)	**-**	**(95)**	**(95)**
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(4)(5)	**-**	**57**	**57**
Balance at June 30, 2011	**(739)**	**(232)**	**(971)**

Balance at December 31, 2009	(592)	(40)	(632)
Change in foreign currency translation gains and losses on investments in foreign operations(1)	80	-	80
Change in gains and losses on financial derivatives to hedge the net investments in foreign operations(2)	(20)	-	(20)
Changes in gains and losses on derivative instruments designated as cash flow hedges(3)	-	(121)	(121)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(4)	-	(2)	(2)
Balance at June 30, 2010	(532)	(163)	(695)

(1) Net of income tax expense of $40 million for the six months ended June 30, 2011 (2010 – recovery of $15 million).
(2) Net of income tax expense of $27 million for the six months ended June 30, 2011 (2010 – recovery of $8 million).
(3) Net of income tax recovery of $39 million for the six months ended June 30, 2011 (2010 – recovery of $84 million).
(4) Net of income tax expense of $34 million for the six months ended June 30, 2011 (2010 – expense of $17 million).
(5) 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 $103 million ($68 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 Equity

(unaudited) *(millions of dollars)*	Six months ended June 30 **2011**	2010
Common Shares		
Balance at beginning of period	**11,636**	10,649
Proceeds from common shares issued	**-**	402
Balance at end of period	**11,636**	11,051
Preferred Shares		
Balance at beginning and end of period	**389**	389
Contributed Surplus		
Balance at beginning of period	**341**	335
Dilution gain from PipeLines LP units issued	**30**	-
Other	**1**	4
Balance at end of period	**372**	339
Retained Earnings		
Balance at beginning of period	**4,258**	4,131
Net income attributable to controlling interests	**767**	593
Common share dividends	**(588)**	(552)
Preferred share dividends	**(11)**	(11)
Balance at end of period	**4,426**	4,161
Accumulated Other Comprehensive (Loss)/Income		
Balance at beginning of period	**(877)**	(632)
Other comprehensive (loss)/income	**(94)**	(63)
Balance at end of period	**(971)**	(695)
	3,455	3,466
Equity Attributable to Controlling Interests	**15,852**	15,245
Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	**768**	785
Net income attributable to non-controlling interests		
PipeLines LP	**49**	39
Portland	**4**	3
Other comprehensive income/(loss) attributable to non-controlling interests	**8**	(3)
Sale of PipeLines LP units		
Proceeds, net of issue costs	**321**	-
Decrease in TCPL's ownership	**(50)**	-
Distributions to non-controlling interests	**(43)**	(44)
Other	**(30)**	17
Balance at end of period	**1,027**	797
Total Equity	**16,879**	16,042

See accompanying notes to the consolidated financial statements.

Notes to Consolidated Financial Statements

(Unaudited)

1. Significant Accounting Policies

The consolidated financial statements of TransCanada PipeLines Limited (TCPL or the Company) have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) as defined in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook, which is discussed further in Note 2. The accounting policies applied are consistent with those outlined in TCPL's annual audited Consolidated Financial Statements for the year ended December 31, 2010. 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 2010 audited Consolidated Financial Statements included in TCPL's 2010 Annual Report. Unless otherwise indicated, "TCPL" or "the Company" includes TransCanada PipeLines Limited and its subsidiaries. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in the Glossary of Terms contained in TCPL's 2010 Annual Report. Amounts are stated in Canadian dollars unless otherwise indicated.

In Natural Gas Pipelines, which consists primarily of the Company's investments in regulated natural gas 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 Oil Pipelines, which consists of the Company's investment in the Keystone crude oil pipeline, annual revenues are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income during any particular fiscal year remain relatively stable with fluctuations resulting from planned and unplanned outages, and changes in the amount of spot volumes transported and the associated rate charged. Spot volumes transported are affected by customer demand, market pricing, planned and unplanned outages of refineries, terminals and pipeline facilities, 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, TCPL 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

Changes in Accounting Policies for 2011

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

Effective January 1, 2011, the Company adopted CICA Handbook Section 1582 "Business Combinations", which is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting the standard is expected to have a significant impact on the way the Company accounts for future business combinations. Entities adopting Section 1582 were also required to adopt CICA Handbook Sections 1601 "Consolidated Financial Statements" and 1602 "Non-Controlling Interests". Sections 1601 and 1602 require Non-Controlling Interests to be presented as part of Equity on the balance sheet. In addition, the income statement of the controlling parent now includes 100 per cent of the subsidiary's results and presents the allocation of income between the controlling and non-controlling interests. Changes resulting from the adoption of Section 1582 were applied prospectively and changes resulting from the adoption of Sections 1601 and 1602 were applied retrospectively.

Future Accounting Changes

U.S. GAAP/International Financial Reporting Standards

The CICA's 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.

In accordance with GAAP, TCPL follows specific accounting policies unique to a rate-regulated business. These rate-regulated accounting (RRA) standards allow the timing of recognition of certain revenues and expenses to differ from the timing that may otherwise be expected in a non-rate-regulated business under GAAP in order to appropriately reflect the economic impact of regulators' decisions regarding the Company's revenues and tolls. The IASB has concluded that the development of RRA under IFRS requires further analysis and has removed the RRA project from its current agenda. TCPL does not expect a final RRA standard under IFRS to be effective in the foreseeable future.

In October 2010, the AcSB and the Canadian Securities Administrators amended their policies applicable to Canadian publicly accountable enterprises that use RRA in order to permit these entities to defer the adoption of IFRS for one year. TCPL deferred its adoption and accordingly will continue to prepare its consolidated financial statements in 2011 in accordance with Canadian GAAP, as defined by Part V of the CICA Handbook, in order to continue using RRA.

As a registrant with the U.S. Securities and Exchange Commission, TCPL prepares and files a "Reconciliation to United States GAAP" and has the option to prepare and file its consolidated financial statements using U.S. GAAP. As a result of the developments noted above, the Company's Board of Directors has approved the adoption of U.S. GAAP effective January 1, 2012. The accounting policies and financial impact of TCPL adopting U.S. GAAP are consistent with that currently reported in the "Reconciliation to United States GAAP" and, as a result, significant changes to existing systems and processes are not required to implement U.S. GAAP as the Company's primary accounting standard.

3. Segmented Information

For the three months ended June 30 *(unaudited)* *(millions of dollars)*	Natural Gas Pipelines 2011	Natural Gas Pipelines 2010	Oil Pipelines[1] 2011	Oil Pipelines[1] 2010	Energy 2011	Energy 2010	Corporate 2011	Corporate 2010	Total 2011	Total 2010
Revenues	1,067	1,061	211	-	865	862	-	-	2,143	1,923
Plant operating costs and other	(356)	(365)	(58)	-	(393)	(377)	(15)	(22)	(822)	(764)
Commodity purchases resold	-	-	-	-	(185)	(216)	-	-	(185)	(216)
Depreciation and amortization	(244)	(251)	(34)	-	(97)	(90)	(4)	-	(379)	(341)
	467	445	119	-	190	179	(19)	(22)	757	602
Interest expense									(262)	(198)
Interest expense of joint ventures									(11)	(15)
Interest income and other									23	(18)
Income taxes expense									(131)	(62)
Net Income									376	309
Net Income Attributable to Non-Controlling Interests									(23)	(17)
Net Income Attributable to Controlling Interests									353	292
Preferred Share Dividends									(5)	(5)
Net Income Attributable to Common Shares									348	287

For the six months ended June 30 *(unaudited)* *(millions of dollars)*	Natural Gas Pipelines 2011	Natural Gas Pipelines 2010	Oil Pipelines[1] 2011	Oil Pipelines[1] 2010	Energy 2011	Energy 2010	Corporate 2011	Corporate 2010	Total 2011	Total 2010
Revenues	2,196	2,190	346	-	1,844	1,688	-	-	4,386	3,878
Plant operating costs and other	(689)	(726)	(94)	-	(759)	(737)	(39)	(48)	(1,581)	(1,511)
Commodity purchases resold	-	-	-	-	(462)	(472)	-	-	(462)	(472)
Depreciation and amortization	(488)	(504)	(57)	-	(197)	(180)	(7)	-	(749)	(684)
	1,019	960	195	-	426	299	(46)	(48)	1,594	1,211
Interest expense									(501)	(392)
Interest expense of joint ventures									(27)	(31)
Interest income and other									56	6
Income taxes expense									(302)	(159)
Net Income									820	635
Net Income Attributable to Non-Controlling Interests									(53)	(42)
Net Income Attributable to Controlling Interests									767	593
Preferred Share Dividends									(11)	(11)
Net Income Attributable to Common Shares									756	582

[1] Commencing in February 2011, TCPL began recording earnings related to the Wood River/Patoka and Cushing Extension sections of Keystone.

Total Assets

(unaudited) *(millions of dollars)*	**June 30, 2011**	December 31, 2010
Natural Gas Pipelines	**22,903**	23,592
Oil Pipelines	**8,781**	8,501
Energy	**12,788**	12,847
Corporate	**2,665**	3,009
	47,137	47,949

4. Long-Term Debt

On July 13, 2011, PipeLines LP entered into a five-year, US$500 million senior syndicated revolving credit facility, maturing July 2016. The proceeds from the credit facility were used to reduce PipeLines LP's term loan and senior revolving credit facility, and repay its bridge loan facility. PipeLines LP's remaining US$300 million term loan matures December 2011.

In June 2011, TCPL retired $60 million of 9.5 per cent Medium-Term Notes and, in January 2011, retired $300 million of 4.3 per cent Medium-Term Notes.

In June 2011, PipeLines LP issued US$350 million of 4.65 per cent Senior Notes due 2021 and cancelled US$175 million of its unsecured syndicated senior credit facility.

In the three and six months ended June 30, 2011, the Company capitalized interest related to capital projects of $68 million and $165 million, respectively (2010 - $143 million and $277 million).

5. Equity and Share Capital

In May 2011, PipeLines LP completed a public offering of 7,245,000 common units at a price of US$47.58 per unit, resulting in gross proceeds of approximately US$345 million. TCPL contributed an additional approximate US$7 million to maintain its general partnership interest and did not purchase any other units. Upon completion of this offering, TCPL's ownership interest in PipeLines LP decreased from 38.2 per cent to 33.3 per cent. In addition, PipeLines LP made draws of US$61 million on a bridge loan facility and of US$125 million on its senior revolving credit facility.

6. Financial Instruments and Risk Management

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

Counterparty Credit and Liquidity Risk

TCPL's maximum counterparty credit exposure with respect to financial instruments at the balance sheet date, without taking into account security held, consisted of accounts receivable, portfolio investments recorded at fair value, the fair value of derivative assets, and notes, loans and advances receivable. The carrying amounts and fair values of these financial assets, except amounts for derivative assets, are included in Accounts Receivable and Other, and Available-For-Sale Assets in the Non-Derivative Financial Instruments Summary table below. Guarantees, 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, 2011, there were no significant amounts past due or impaired.

At June 30, 2011, the Company had a credit risk concentration of $286 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 Storage Commodity Price Risk

At June 30, 2011, 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 $47 million (December 31, 2010 - $49 million). The change in the fair value adjustment of proprietary natural gas inventory in storage in the three and six months ended June 30, 2011 resulted in net pre-tax unrealized losses of $1 million and gains of $1 million, respectively (2010 – gains of $4 million and losses of $20 million, respectively), which were recorded as adjustments to Revenues and Inventories. The change in fair value of natural gas forward purchase and sale contracts in the three and six months ended June 30, 2011 resulted in net pre-tax unrealized losses of $3 million and $10 million, respectively (2010 – gains of $2 million and $5 million, respectively), which were included in Revenues.

VaR Analysis

TCPL uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its liquid open 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. TCPL's consolidated VaR was $11 million at June 30, 2011, which was consistent with VaR at December 31, 2010 of $12 million.

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, 2011, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $9.5 billion (US$9.8 billion) and a fair value of $10.8 billion (US$11.2 billion). At June 30, 2011, $279 million (December 31, 2010 - $181 million) was included in Other Current Assets and 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) *(unaudited)* *(millions of dollars)*	**June 30, 2011** **Fair Value**[1]	 **Notional or Principal Amount**	December 31, 2010 Fair Value[1]	 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2011 to 2018)	**276**	**US 3,550**	179	US 2,800
U.S. dollar forward foreign exchange contracts (maturing 2011)	**3**	**US 600**	2	US 100
	279	**US 4,150**	181	US 2,900

(1) Fair values equal carrying values.

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

Non-Derivative Financial Instruments Summary

(unaudited) (millions of dollars)	June 30, 2011 Carrying Amount	June 30, 2011 Fair Value	December 31, 2010 Carrying Amount	December 31, 2010 Fair Value
Financial Assets(1)				
Cash and cash equivalents	**455**	**455**	752	752
Accounts receivable and other(2)(3)	**1,502**	**1,534**	1,564	1,604
Due from TransCanada Corporation	**1,249**	**1,249**	1,363	1,363
Available-for-sale assets(2)	**22**	**22**	20	20
	3,228	**3,260**	3,699	3,739
Financial Liabilities(1)(3)				
Notes payable	**1,628**	**1,628**	2,092	2,092
Accounts payable and deferred amounts(4)	**1,059**	**1,059**	1,444	1,444
Due to TransCanada Corporation	**2,796**	**2,796**	2,703	2,703
Accrued interest	**403**	**403**	361	361
Long-term debt	**17,340**	**20,498**	17,922	21,523
Long-term debt of joint ventures	**839**	**946**	866	971
Junior subordinated notes	**955**	**962**	985	992
	25,020	**28,292**	26,373	30,086

(1) Consolidated Net Income in the three and six months ended June 30, 2011 included losses of $2 million and $11 million, respectively, (2010 – losses of $2 million and $9 million, respectively), for fair value adjustments related to interest rate swap agreements on US$350 million (2010 – US$150 million) of Long-Term Debt. There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

(2) At June 30, 2011, the Consolidated Balance Sheet included financial assets of $1,181 million (December 31, 2010 – $1,280 million) in Accounts Receivable, $38 million (December 31, 2010 – $40 million) in Other Current Assets and $305 million (December 31, 2010 - $264 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost, except for the US$350 million (December 31, 2010 – US$250 million) of Long-Term Debt that is adjusted to fair value.

(4) At June 30, 2011, the Consolidated Balance Sheet included financial liabilities of $1,024 million (December 31, 2010 – $1,414 million) in Accounts Payable and $35 million (December 31, 2010 - $30 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, 2011 *(unaudited)* *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[(1)]				
Fair Values [(2)]				
Assets	**$149**	**$118**	**$6**	**$18**
Liabilities	**$(114)**	**$(146)**	**$(15)**	**$(19)**
Notional Values				
Volumes[(3)]				
Purchases	**21,569**	**155**	**-**	**-**
Sales	**23,961**	**123**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**634**
U.S. dollars	**-**	**-**	**US 1,622**	**US 250**
Cross-currency	**-**	**-**	**47/US 37**	**-**
Net unrealized gains/(losses) in the period[(4)]				
Three months ended June 30, 2011	**$4**	**$(9)**	**$(2)**	**$1**
Six months ended June 30, 2011	**$3**	**$(26)**	**$-**	**$-**
Net realized gains/(losses) in the period[(4)]				
Three months ended June 30, 2011	**$8**	**$(15)**	**$12**	**$3**
Six months ended June 30, 2011	**$11**	**$(41)**	**$33**	**$5**
Maturity dates	**2011-2018**	**2011-2016**	**2011-2012**	**2012-2016**
Derivative Financial Instruments in Hedging Relationships[(5)(6)]				
Fair Values [(2)]				
Assets	**$57**	**$5**	**$-**	**$11**
Liabilities	**$(197)**	**$(17)**	**$(56)**	**$(14)**
Notional Values				
Volumes[(3)]				
Purchases	**18,524**	**14**	**-**	**-**
Sales	**9,187**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**US 120**	**US 1,000**
Cross-currency	**-**	**-**	**136/US 100**	**-**
Net realized losses in the period[(4)]				
Three months ended June 30, 2011	**$(8)**	**$(5)**	**$-**	**$(4)**
Six months ended June 30, 2011	**$(46)**	**$(8)**	**$-**	**$(9)**
Maturity dates	**2011-2017**	**2011-2013**	**2011- 2014**	**2011-2015**

(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 gigawatt hours (GWh) and billion cubic feet (Bcf), respectively.

(4) Realized and unrealized gains and losses on held-for-trading derivative financial instruments used to purchase and sell power and natural gas are included on a net basis 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 cash flow hedging relationships is initially recognized in Other Comprehensive Income and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $11 million and a notional amount of US$350 million at June 30, 2011. Net realized gains on fair value hedges for the three and six months ended June 30, 2011 were $2 million and $4 million, respectively, and were included in Interest Expense. In the three and six months ended June 30, 2011, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) For the three and six months ended June 30, 2011, Net Income included gains of $2 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. For the three and six months ended June 30, 2011, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

2010

(unaudited) *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading				
Fair Values(1) (2)				
Assets	$169	$144	$8	$20
Liabilities	$(129)	$(173)	$(14)	$(21)
Notional Values(2)				
Volumes(3)				
Purchases	15,610	158	-	-
Sales	18,114	96	-	-
Canadian dollars	-	-	-	736
U.S. dollars	-	-	US 1,479	US 250
Cross-currency	-	-	47/US 37	-
Net unrealized (losses)/gains in the period(4)				
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(4)				
Three months ended June 30, 2010	$15	$(17)	$(6)	$(6)
Six months ended June 30, 2010	$37	$(29)	$2	$(10)
Maturity dates(2)	2011-2015	2011-2015	2011-2012	2011-2016
Derivative Financial Instruments in Hedging Relationships(5)(6)				
Fair Values(1) (2)				
Assets	$112	$5	$-	$8
Liabilities	$(186)	$(19)	$(51)	$(26)
Notional Values(2)				
Volumes(3)				
Purchases	16,071	17	-	-
Sales	10,498	-	-	-
U.S. dollars	-	-	US 120	US 1,125
Cross-currency	-	-	136/US 100	-
Net realized losses in the period(4)				
Three months ended June 30, 2010	$(36)	$(6)	$-	$(9)
Six months ended June 30, 2010	$(43)	$(9)	$-	$(19)
Maturity dates(2)	2011-2015	2011-2013	2011-2014	2011-2015

(1) Fair values equal carrying values.
(2) As at December 31, 2010.
(3) Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.
(4) Realized and unrealized gains and losses on held-for-trading derivative financial instruments used to purchase and sell power and natural gas are included on a net basis 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 cash flow hedging relationships is initially recognized in Other Comprehensive Income and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.
(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $8 million and a notional amount of US$250 million at December 31, 2010. 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 the three and six months ended June 30, 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) For the three and six months ended June 30, 2010, Net Income 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. For the three and six months ended June 30, 2010, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts were 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:

(unaudited) *(millions of dollars)*	**June 30, 2011**	December 31, 2010
Current		
Other current assets	**299**	273
Accounts payable	**(314)**	(337)
Long-term		
Intangibles and other assets	**344**	374
Deferred amounts	**(264)**	(282)

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. In Level I, the fair value of assets and liabilities is determined by reference to quoted prices in active markets for identical assets and liabilities. In Level II, determination of the fair value of assets and liabilities includes valuations using inputs, other than quoted prices, for which all significant inputs are observable, directly or indirectly. This category includes fair value determined using valuation techniques such as option pricing models and extrapolation using observable inputs. In Level III, determination of the fair value of assets and liabilities is based on inputs that are not readily observable and are significant to the overall fair value measurement. Long-dated commodity transactions in certain markets 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.

There were no transfers between Level I and Level II in the three and six months ended June 30, 2011. - Financial assets and liabilities measured at fair value, including both current and non-current portions, are categorized as follows:

Assets/(Liabilities)	Quoted Prices in Active Markets (Level 1)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total	
(unaudited) *(millions of dollars, pre-tax)*	**June 30 2011**	Dec 31 2010	**June 30 2011**	Dec 31 2010	**June 30 2011**	Dec 31 2010	**June 30 2011**	Dec 31 2010
Natural Gas Inventory	**-**	-	**47**	49	**-**	-	**47**	49
Derivative Financial Instrument Assets:								
Interest rate contracts	**-**	-	**29**	28	**-**	-	**29**	28
Foreign exchange contracts	**11**	10	**278**	179	**-**	-	**289**	189
Power commodity contracts	**-**	-	**194**	269	**3**	5	**197**	274
Natural gas commodity contracts	**68**	93	**53**	56	**-**	-	**121**	149
Derivative Financial Instrument Liabilities:								
Interest rate contracts	**-**	-	**(32)**	(47)	**-**	-	**(32)**	(47)
Foreign exchange contracts	**(17)**	(11)	**(59)**	(54)	**-**	-	**(76)**	(65)
Power commodity contracts	**-**	-	**(272)**	(299)	**(30)**	(8)	**(302)**	(307)
Natural gas commodity contracts	**(133)**	(178)	**(28)**	(15)	**-**	-	**(161)**	(193)
Non-Derivative Financial Instruments:								
Available-for-sale assets	**22**	20	**-**	-	**-**	-	**22**	20
	(49)	(66)	**210**	166	**(27)**	(3)	**134**	97

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:

(unaudited) *(millions of dollars, pre-tax)*	Derivatives[1] **2011**	Derivatives[1] 2010
Balance at January 1	**(3)**	(2)
New contracts[2]	**1**	(10)
Transfers out of Level III[3]	**(4)**	(15)
Settlements	**-**	(2)
Change in unrealized gains recorded in Net Income	**1**	14
Change in unrealized (losses)/gains recorded in Other Comprehensive Income	**(22)**	10
Balance at June 30	**(27)**	(5)

(1) The fair value of derivative assets and liabilities is presented on a net basis.
(2) For the three and six months ended June 30, 2011, there were no amounts (2010 – gain of $1 million and nil, respectively), included in Net Income attributable to derivatives that were entered into during the period and still held at the reporting date.
(3) As contracts near maturity, they are transferred out of Level III and into Level II.

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $12 million decrease or increase, respectively, in the fair value of derivative financial instruments included in Level III and outstanding as at June 30, 2011.

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	Pension Benefit Plans		Other Benefit Plans	
(unaudited)(millions of dollars)	**2011**	2010	**2011**	2010
Current service cost	**13**	13	**1**	1
Interest cost	**22**	22	**2**	2
Expected return on plan assets	**(28)**	(27)	**(1)**	(1)
Amortization of transitional obligation related to regulated business	**-**	-	**1**	1
Amortization of net actuarial loss	**5**	2	**1**	1
Amortization of past service costs	**1**	1	**-**	-
Net benefit cost recognized	**13**	11	**4**	4

Six months ended June 30	Pension Benefit Plans		Other Benefit Plans	
(unaudited)(millions of dollars)	**2011**	2010	**2011**	2010
Current service cost	**27**	25	**1**	1
Interest cost	**45**	45	**4**	4
Expected return on plan assets	**(56)**	(54)	**(1)**	(1)
Amortization of transitional obligation related to regulated business	**-**	-	**1**	1
Amortization of net actuarial loss	**11**	4	**1**	1
Amortization of past service costs	**2**	2	**-**	-
Net benefit cost recognized	**29**	22	**6**	6

8. Dispositions

On May 3, 2011, the Company completed the sale of a 25 per cent interest in each of Gas Transmission Northwest LLC (GTN LLC) and Bison Pipeline LLC (Bison LLC) to PipeLines LP for an aggregate purchase price of US$605 million, subject to closing adjustments, which included US$81 million of long-term debt, or 25 per cent of GTN LLC debt outstanding. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively.

On May 3, 2011, PipeLines LP completed an underwritten public offering of 7,245,000 common units, including 945,000 common units purchased by the underwriters upon full exercise of an over-allotment option, at US$47.58 per unit. Gross proceeds of approximately US$345 million from this offering were used to partially fund the acquisition. The acquisition was also funded by draws of US$61 million on PipeLines LP's bridge loan facility and of US$125 million on its US$250 million senior revolving credit facility.

As part of this offering, TCPL made a capital contribution of approximately US$7 million to maintain its two per cent general partnership interest in PipeLines LP and did not purchase any other units. As a result of the common units offering, TCPL's ownership in PipeLines LP decreased from 38.2 per cent to 33.3 per cent and an after-tax dilution gain of $30 million ($50 million pre-tax) was recorded in Contributed Surplus.

9. Contingencies

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. No amounts recorded in revenues in the first six months of 2011 are expected to be repaid.

10. Related Party Transactions

The following amounts are included in Due from TransCanada Corporation:

		2011		2010	
(millions of dollars)	Maturity Dates	**Outstanding December 31**	**Interest Rate**	Outstanding December 31	Interest Rate
Discount Notes	2011	**2,664**	**1.4%**	2,566	1.4%
Credit Facility		**(1,415)**	**3.0%**	(1,203)	2.3%
		1,249		1,363	

The following amounts are included in Due to TransCanada Corporation:

		2011		2010	
(millions of dollars)	Maturity Dates	**Outstanding December 31**	**Interest Rate**	Outstanding December 31	Interest Rate
Credit Facility	2012	**2,796**	**3.8%**	2,703	3.8%

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

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