Quarterly Report to Shareholders

Management's Discussion and Analysis

Management's Discussion and Analysis (MD&A) dated April 29, 2010 should be read in conjunction with the accompanying unaudited Consolidated Financial Statements of TransCanada PipeLines Limited (TCPL or the Company) for the three months ended March 31, 2010. It should also be read in conjunction with the audited Consolidated Financial Statements and notes thereto, and the MD&A contained in TCPL's 2009 Annual Report for the year ended December 31, 2009. 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 TransCanada PipeLines Limited. Unless otherwise indicated, "TCPL" or "the Company" includes TransCanada PipeLines Limited and its subsidiaries. Amounts are stated in Canadian dollars unless otherwise indicated. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in the Glossary of Terms contained in TCPL's 2009 Annual Report.

Forward-Looking Information

This MD&A may contain certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "should", "estimate", "project", "outlook", "forecast" or other similar words are used to identify such forward-looking information. Forward-looking statements in this document are intended to provide 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), 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, 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, 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 and Funds Generated from Operations in this MD&A. These measures do not have any standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP). They are, therefore, considered to be non-GAAP measures and may not be comparable to similar measures presented by other entities. Management of 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. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, non-controlling interests and preferred share dividends. EBIT is a measure of the Company's earnings from ongoing operations. EBIT comprises earnings before deducting interest and other financial charges, income taxes, non-controlling interests and preferred share dividends.

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

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

Consolidated Results of Operations

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

For the three months ended March 31 *(unaudited)(millions of dollars)*	Pipelines **2010**	Pipelines 2009	Energy **2010**	Energy 2009	Corporate **2010**	Corporate 2009	Total **2010**	Total 2009
Comparable EBITDA[1]	**768**	871	**259**	290	**(26)**	(30)	**1,001**	1,131
Depreciation and amortization	**(253)**	(260)	**(90)**	(86)	**-**	-	**(343)**	(346)
Comparable EBIT[1]	**515**	611	**169**	204	**(26)**	(30)	**658**	785
Specific items:								
Fair value adjustments of U.S. Power derivative contracts	**-**	-	**(28)**	-	**-**	-	**(28)**	-
Fair value adjustments of natural gas inventory in storage and forward contracts	**-**	-	**(21)**	(13)	**-**	-	**(21)**	(13)
EBIT[1]	**515**	611	**120**	191	**(26)**	(30)	**609**	772
Interest expense							**(194)**	(301)
Interest expense of joint ventures							**(16)**	(14)
Interest income and other							**24**	22
Income taxes							**(97)**	(114)
Non-controlling interests							**(25)**	(29)
Net Income							**301**	336
Preferred share dividends							**(6)**	(6)
Net Income Applicable to Common Shares							**295**	330
Specific items (net of tax):								
Fair value adjustments of U.S. Power derivative contracts							**17**	-
Fair value adjustments of natural gas inventory in storage and forward contracts							**15**	9
Comparable Earnings[1]							**327**	339

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

TCPL's Net Income was $301 million and Net Income Applicable to Common Shares was $295 million in first quarter 2010 compared to $336 million and $330 million, respectively, in first quarter 2009. The $35 million decrease in Net Income and Net Income Applicable to Common Shares reflected:

- decreased EBIT from Pipelines primarily due to the negative impact of a weaker U.S. dollar, lower revenues from certain Other U.S. Pipelines, and higher business development costs relating to the Alaska pipeline project;

- decreased EBIT from Energy primarily due to reduced realized power prices in Western Power, lower volumes and higher operating costs at Bruce A, and lower contracted earnings at Bécancour, partially offset by increased capacity payments at Ravenswood, higher third-party storage revenues for Natural Gas Storage and incremental earnings from Portlands Energy which went into service in April 2009; and

- decreased Interest Expense primarily due to increased capitalized interest and the positive effect of a weaker U.S. dollar on U.S. dollar-denominated interest.

Comparable Earnings in first quarter 2010 decreased $12 million to $327 million, compared to $339 million for the same period in 2009. Comparable Earnings in first quarter 2010 excluded net unrealized after tax losses of $17 million ($28 million pre-tax) resulting from changes in the fair value of certain U.S. Power derivative contracts. Effective January 1, 2010, these unrealized losses have been removed from Comparable Earnings as they are not representative of amounts that will be realized on settlement of the contracts. Comparative amounts in 2009 were not material and therefore were not excluded from the computation of Comparable Earnings. Comparable Earnings in first quarter 2010 and 2009 also excluded net unrealized after tax losses of $15 million ($21 million pre-tax) and $9 million ($13 million pre-tax), respectively, resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. Pipelines and Energy EBIT is largely offset by the impact on U.S. dollar-denominated interest. The resultant net exposure is managed using derivatives, effectively reducing the Company's exposure to changes in foreign exchange rates. The average U.S. dollar exchange rate for the three months ended March 31, 2010 was 1.04 (2009 - 1.25).

Results from each of the segments for first quarter 2010 are discussed further in the Pipelines, Energy and Corporate sections of this MD&A.

Pipelines

Pipelines' Comparable EBIT and EBIT were $515 million in first quarter 2010 compared to $611 million for the same period in 2009.

Pipelines Results

(unaudited) *(millions of dollars)*	Three months ended March 31 **2010**	2009
Canadian Pipelines		
Canadian Mainline	**265**	284
Alberta System	**175**	168
Foothills	**33**	34
Other (TQM, Ventures LP)	**13**	19
Canadian Pipelines Comparable EBITDA(1)	**486**	505
U.S. Pipelines		
ANR	**120**	133
GTN(2)	**45**	61
Great Lakes	**33**	44
PipeLines LP(2)(3)	**26**	29
Iroquois	**19**	23
Portland(4)	**10**	14
International (Tamazunchale, TransGas, Gas Pacifico/INNERGY)	**10**	13
General, administrative and support costs(5)	**(6)**	(3)
Non-controlling interests(6)	**48**	60
U.S. Pipelines Comparable EBITDA(1)	**305**	374
Business Development Comparable EBITDA(1)	**(23)**	(8)
Pipelines Comparable EBITDA(1)	**768**	871
Depreciation and amortization	**(253)**	(260)
Pipelines Comparable EBIT and EBIT(1)	**515**	611

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA, Comparable EBIT and EBIT.
(2) GTN's results include North Baja until July 1, 2009 when it was sold to PipeLines LP.
(3) PipeLines LP's results reflect TCPL's ownership interest in PipeLines LP of 38.2 per cent in first quarter 2010 (first quarter 2009 – 32.1 per cent).
(4) Portland's results reflect TCPL's 61.7 per cent ownership interest.
(5) Represents certain costs associated with supporting the Company's Canadian and U.S. Pipelines.
(6) Non-controlling interests reflects Comparable EBITDA for the portions of PipeLines LP and Portland not owned by TCPL.

Net Income for Wholly Owned Canadian Pipelines

(unaudited) *(millions of dollars)*	Three months ended March 31 **2010**	2009
Canadian Mainline	**66**	66
Alberta System	**38**	39
Foothills	**6**	6

Canadian Pipelines

Canadian Mainline's Comparable EBITDA for first quarter 2010 of $265 million decreased $19 million compared to the same period in 2009 primarily due to lower revenues as a result of lower income taxes and financial charges in the 2010 tolls, which are recovered on a flow-through basis and do not impact net income. The decrease in financial charges was primarily due to higher cost debt that matured in 2009.

The Alberta System’s net income was $38 million in first quarter 2010 compared to $39 million in first quarter 2009. The impact of a higher average investment base in first quarter 2010 was offset by lower earnings due to the expiration of the 2008-2009 Revenue Requirement Settlement. Net income in 2010 reflects a rate of return on common equity (ROE) of 8.75 per cent on a deemed common equity of 35 per cent.

The Alberta System's Comparable EBITDA was $175 million in first quarter 2010 compared to $168 million in the same quarter of 2009. The increase was due to higher revenues as a result of a higher return associated with an increased average investment base and a recovery of increased depreciation and income taxes, partially offset by lower earnings due to the expiration of the 2008-2009 Revenue Requirement Settlement. Depreciation and income taxes are recovered on a flow-through basis and do not impact net income.

Comparable EBITDA from Other Canadian Pipelines was $13 million for first quarter 2010 compared to $19 million for the same period in 2009. The decrease in first quarter 2010 was primarily due to an adjustment recorded in first quarter 2009 for a National Energy Board of Canada (NEB) decision to retroactively increase TQM’s allowed rate of return on capital for 2008 and 2007.

U.S. Pipelines

ANR’s Comparable EBITDA for first quarter 2010 of $120 million decreased $13 million compared to $133 million for the same period in 2009 primarily due to the negative impact of a weaker U.S. dollar, partially offset by lower operating, maintenance and administration (OM&A) costs and increased incidental natural gas and condensate sales.

GTN’s Comparable EBITDA for first quarter 2010 decreased $16 million from the same period in 2009 primarily due to the negative impact of a weaker U.S. dollar and the sale of North Baja to PipeLines LP in July 2009.

Comparable EBITDA for the remainder of the U.S. Pipelines was $140 million for first quarter 2010 compared to $180 million for the same period in 2009. The decrease was primarily due to the negative impact of a weaker U.S. dollar on U.S. Pipelines operations and lower revenues from Great Lakes, Northern Border and Portland, partially offset by the acquisition of North Baja by PipeLines LP.

Business Development

Pipelines’ Business Development Comparable EBITDA losses increased $15 million in first quarter 2010 compared to the same period in 2009 primarily due to higher business development costs related to the continued advancement of the Alaska pipeline project. The State of Alaska has agreed to reimburse certain of TCPL’s eligible pre-construction costs, as they are incurred and approved by the state, to a maximum of US$500 million. Such reimbursements are shared proportionately with ExxonMobil, TCPL’s joint venture partner in developing the Alaska pipeline project.

Operating Statistics

Three months ended March 31 (*unaudited*)	Canadian Mainline[1] 2010	Canadian Mainline[1] 2009	Alberta System[2] 2010	Alberta System[2] 2009	Foothills 2010	Foothills 2009	ANR[3] 2010	ANR[3] 2009	GTN[3] 2010	GTN[3] 2009
Average investment base ($millions)	**6,629**	6,590	**4,956**	4,586	**677**	725	**n/a**	n/a	**n/a**	n/a
Delivery volumes (Bcf)										
Total	**560**	646	**938**	1,027	**328**	323	**447**	491	**207**	195
Average per day	**6.2**	7.2	**10.4**	11.4	**3.6**	3.6	**5.0**	5.5	**2.3**	2.2

(1) Canadian Mainline's throughput volumes in the above table reflect physical deliveries to domestic and export markets. Throughput volumes reported in previous years reflected contract deliveries, however, customer contracting patterns have changed in recent years making physical deliveries a better measure of system utilization. Canadian Mainline's physical receipts originating at the Alberta border and in Saskatchewan for the three months ended March 31, 2010 were 385 billion cubic feet (Bcf) (2009 – 472 Bcf); average per day was 4.3 Bcf (2009 – 5.3 Bcf).

(2) Field receipt volumes for the Alberta System for the three months ended March 31, 2010 were 855 Bcf (2009 – 909 Bcf); average per day was 9.5 Bcf (2009 – 10.1 Bcf).

(3) ANR's and GTN's results are not impacted by average investment base as these systems operate under fixed rate models approved by the U.S. Federal Energy Regulatory Commission.

Capitalized Project Costs

As at March 31, 2010, TCPL had advanced $144 million to the Aboriginal Pipeline Group (APG) with respect to the Mackenzie Gas Pipeline Project (MGP). TCPL and the other co-venture companies involved in the MGP continue to pursue approval of the proposed project, focusing on obtaining regulatory approval and the Canadian government's support of an acceptable fiscal framework. The NEB recently concluded the final argument hearings for the project and is expected to release its conclusions on the project's application in September 2010. Project timing continues to be uncertain. In the event the co-venture group is unable to reach an agreement with the government on an acceptable fiscal framework, the parties will need to determine the appropriate next steps for the project. For TCPL, this may result in a reassessment of the carrying amount of the APG advances.

Energy

Energy's Comparable EBIT was $169 million in first quarter 2010 compared to $204 million in first quarter 2009. Comparable EBIT in first quarter 2010 excluded net unrealized losses of $28 million resulting from changes in the fair value of certain U.S. Power derivative contracts. Comparable EBIT in first quarter 2010 and 2009 also excluded net unrealized losses of $21 million and $13 million, respectively, from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Items excluded from Comparable Earnings are discussed further under the headings U.S. Power and Natural Gas Storage in this section.

Energy Results

(unaudited) (millions of dollars)	Three months ended March 31 2010	2009
Canadian Power		
Western Power	**42**	93
Eastern Power[1]	**52**	52
Bruce Power	**63**	99
General, administrative and support costs	**(10)**	(8)
Canadian Power Comparable EBITDA[2]	**147**	236
U.S. Power		
Northeast Power[3]	**75**	42
General, administrative and support costs	**(9)**	(12)
U.S. Power Comparable EBITDA[2]	**66**	30
Natural Gas Storage		
Alberta Storage	**53**	39
General, administrative and support costs	**(2)**	(3)
Natural Gas Storage Comparable EBITDA[2]	**51**	36
Business Development Comparable EBITDA[2]	**(5)**	(12)
Energy Comparable EBITDA[2]	**259**	290
Depreciation and amortization	**(90)**	(86)
Energy Comparable EBIT[2]	**169**	204
Specific items:		
Fair value adjustments of U.S. Power derivative contracts	**(28)**	-
Fair value adjustments of natural gas inventory in storage and forward contracts	**(21)**	(13)
Energy EBIT[2]	**120**	191

(1) Includes Portlands Energy effective April 2009.
(2) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA, Comparable EBIT and EBIT.
(3) Includes phase one of Kibby Wind effective October 2009.

Western and Eastern Canadian Power

Western and Eastern Canadian Power Comparable EBITDA[1][2]

(unaudited) (millions of dollars)	Three months ended March 31 2010	2009
Revenues		
Western power	**164**	215
Eastern power	**67**	69
Other[3]	**22**	12
	253	296
Commodity Purchases Resold		
Western power	**(106)**	(98)
Other[3][4]	**(5)**	(9)
	(111)	(107)
Plant operating costs and other	**(48)**	(44)
General, administrative and support costs	**(10)**	(8)
Comparable EBITDA[1]	**84**	137

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA.
(2) Includes Portlands Energy effective April 2009.

(3) Includes sales of excess natural gas purchased for generation and thermal carbon black. Effective January 1, 2010, the net impact of derivatives used to purchase and sell natural gas to manage Western and Eastern Power's assets is presented on a net basis in Other Revenues. Comparative results for 2009 reflect amounts reclassified from Other Commodity Purchases Resold to Other Revenues.
(4) Includes the cost of excess natural gas not used in operations.

Western and Eastern Canadian Power Operating Statistics[1]

(unaudited)	Three months ended March 31 **2010**	2009
Sales Volumes (GWh)		
Supply		
Generation		
Western Power	**585**	605
Eastern Power	**429**	355
Purchased		
Sundance A & B and Sheerness PPAs	**2,655**	2,440
Other purchases	**149**	185
	3,818	3,585
Sales		
Contracted		
Western Power	**2,269**	2,053
Eastern Power	**445**	391
Spot		
Western Power	**1,104**	1,141
	3,818	3,585
Plant Availability		
Western Power[2]	**95%**	91%
Eastern Power	**96%**	97%

(1) Includes Portlands Energy effective April 2009.
(2) Excludes facilities that provide power to TCPL under PPAs.

Western Power's Comparable EBITDA of $42 million and Power Revenues of $164 million in first quarter 2010 both decreased $51 million compared to the same period in 2009. These decreases were primarily due to lower revenues from the Alberta power portfolio resulting from lower overall realized power prices, partially offset by higher volumes of power sold. Average spot market power prices in Alberta decreased 35 per cent to $41 per megawatt hour (MWh) in first quarter 2010 compared to $63 per MWh in first quarter 2009.

Western Power's Commodity Purchases Resold increased $8 million in first quarter 2010 compared to the same period in 2009 primarily due to higher purchased power volumes under the Alberta power purchase arrangements (PPAs).

Eastern Power's Comparable EBITDA of $52 million in first quarter 2010 was consistent with the same period in 2009. Increased revenues due to incremental earnings from Portlands Energy, which went in service in April 2009, were offset by lower contracted earnings from Bécancour.

Plant Operating Costs and Other, which includes fuel gas consumed in generation, of $48 million for first quarter 2010 increased from the same period in 2009 primarily due to incremental fuel consumed at Portlands Energy, partially offset by lower prices for natural gas fuel in Western Power.

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 case of an unexpected plant outage. The overall amount of spot market volumes is dependent upon the ability to transact in forward sales markets at acceptable contract terms. This approach to portfolio management helps to minimize costs in situations where Western Power would otherwise have to purchase electricity in the open market to fulfill its contractual sales obligations. Approximately 67 per cent of Western Power sales volumes were sold under contract in first quarter 2010, compared to 64 per cent in first quarter 2009. To reduce its exposure to spot market prices on uncontracted volumes, as at March 31, 2010, Western Power had entered into fixed-price power sales contracts to sell approximately 7,000 gigawatt hours (GWh) for the remainder of 2010 and 6,100 GWh for 2011.

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

Bruce Power

Bruce Power Results

(TCPL's proportionate share) *(unaudited)* *(millions of dollars unless otherwise indicated)*	Three months ended March 31 **2010**	 2009
Revenues[1]	**225**	221
Operating Expenses	**(162)**	(122)
Comparable EBITDA[2]	**63**	99
Bruce A Comparable EBITDA[2]	**13**	41
Bruce B Comparable EBITDA[2]	**50**	58
Comparable EBITDA[2]	**63**	99
Bruce Power – Other Information		
Plant availability		
Bruce A	**65%**	97%
Bruce B	**98%**	96%
Combined Bruce Power	**87%**	96%
Planned outage days		
Bruce A	**35**	-
Bruce B	**-**	-
Unplanned outage days		
Bruce A	**26**	5
Bruce B	**6**	8
Sales volumes (GWh)		
Bruce A	**989**	1,495
Bruce B	**2,155**	2,139
	3,144	3,634
Results per MWh		
Bruce A power revenues	**$64**	$63
Bruce B power revenues[3]	**$58**	$52
Combined Bruce Power revenues	**$60**	$57
Percentage of Bruce B output sold to spot market[4]	**78%**	36%

(1) Revenues include Bruce A's fuel cost recoveries of $5 million for the three months ended March 31, 2010 (2009 - $10 million). Revenues also include Bruce B unrealized losses of $1 million as a result of changes in the fair value of power derivatives for the three months ended March 31, 2010 (2009 – $2 million gain).
(2) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA.
(3) Includes revenues received under the floor price mechanism and contract settlements.
(4) All of Bruce B's output is covered by the floor price mechanism, including volumes sold to the spot market.

TCPL's proportionate share of Bruce Power's Comparable EBITDA decreased $36 million to $63 million in first quarter 2010 compared to $99 million in first quarter 2009 as a result of lower volumes and increased operating expenses due to an increase in outage days, partially offset by the impact of 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 to TCPL reflects TCPL's higher percentage ownership interest in Bruce A.

TCPL's proportionate share of Bruce A's Comparable EBITDA decreased $28 million to $13 million in first quarter 2010 compared to $41 million in first quarter 2009 as a result of decreased volumes and higher operating costs due to increased planned and unplanned outages, partially offset by the payment received from Bruce B. Bruce A's plant availability in first quarter 2010 was 65 per cent as a result of 61 outage days compared to an availability of 97 per cent and five outage days in the same period in 2009.

TCPL's proportionate share of Bruce B's Comparable EBITDA decreased $8 million to $50 million in first quarter 2010 compared to $58 million in first quarter 2009 primarily due to the payment made to Bruce A, partially offset by higher realized prices resulting from the recognition of payments received pursuant to the floor price mechanism in Bruce B's contract with the OPA.

In second quarter 2009, Bruce B's contract with the OPA was amended such that, beginning in 2009, annual net payments received under the floor price mechanism will not be subject to repayment in future years. The support payments recognized by Bruce B in second quarter 2009 included an amount for first quarter 2009. Had this amount been included in first quarter 2009, the realized price on Bruce B revenues in first quarter 2009 would be consistent with the $58 per MWh realized in 2010.

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

TCPL's share of Bruce Power's generation in first quarter 2010 decreased to 3,144 GWh compared to 3,634 GWh in first quarter 2009, primarily due to an increase in the planned and unplanned outage days at Bruce A in first quarter 2010. Bruce Power units' combined average availability was 87 per cent in first quarter 2010 compared to 96 per cent in first quarter 2009.

Under a contract with the OPA, all of the output from Bruce A in first quarter 2010 was sold at a fixed price of $64.45 per MWh (before recovery of fuel costs from the OPA) compared to $63.00 per MWh in first quarter 2009. All output from the Bruce B units were subject to a floor price of $48.76 per MWh in first quarter 2010 and $47.66 per MWh in first quarter 2009. Both the Bruce A and Bruce B contract prices are adjusted annually for inflation on April 1. Effective April 1, 2010, the fixed price for output from Bruce A increased to $64.71 per MWh and the Bruce B floor price increased to $48.96 per MWh.

Bruce B also enters into fixed-price contracts whereby Bruce B receives or pays the difference between the contract price and the spot price. Bruce B's realized price of $58 per MWh in first quarter 2010 reflects revenues recognized from both the floor price mechanism and contract sales. A significant portion of these contracts will expire by the end of 2010, which is expected to result in lower realized prices at Bruce B for future periods. At March 31, 2010, Bruce B had sold forward approximately 1,200 GWh and 300 GWh, representing TCPL's proportionate share, for the remainder of 2010 and 2011, respectively.

The overall plant availability percentage in 2010 is expected to be in the mid-80s for the two operating Bruce A units and in the high 80s for the four Bruce B units. A planned outage of Bruce A Unit 3 began in late February 2010 and ended April 25, 2010. Maintenance outages of approximately eight weeks are scheduled to begin in mid-May 2010 for Bruce B Unit 6 and mid-October 2010 for Bruce B Unit 5.

As at March 31, 2010, Bruce A had incurred approximately $3.4 billion in costs for the refurbishment and restart of Units 1 and 2, and approximately $0.2 billion for the refurbishment of Units 3 and 4.

U.S. Power

U.S. Power Comparable EBITDA[1][2]

(unaudited) *(millions of dollars)*	Three months ended March 31 2010	2009
Revenues		
Power[3]	**241**	272
Capacity	**42**	30
Other[3][4]	**26**	46
	309	348
Commodity purchases resold[3]	**(142)**	(122)
Plant operating costs and other[4]	**(92)**	(184)
General, administrative and support costs	**(9)**	(12)
Comparable EBITDA[1]	**66**	30

(1) Refer to the Non-GAAP Measures section of this MD&A for further discussion of Comparable EBITDA.
(2) Includes phase one of Kibby Wind effective October 2009.
(3) Effective January 1, 2010, the net impact of derivatives used to purchase and sell power, natural gas and fuel oil to manage U.S. Power's assets is presented on a net basis in Power Revenues. Comparative results for 2009 reflect amounts reclassified from Commodity Purchases Resold and Other Revenues to Power Revenues.
(4) Includes revenues and costs related to a third-party service agreement at Ravenswood.

U.S. Power Operating Statistics[1]

(unaudited)	Three months ended March 31 2010	2009
Sales Volumes (GWh)		
Supply		
Generation	**891**	1,168
Purchased	**2,486**	1,259
	3,377	2,427
Sales		
Contracted	**3,215**	2,140
Spot	**162**	287
	3,377	2,427
Plant Availability	**86%**	58%

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

U.S. Power's Comparable EBITDA for first quarter 2010 of $66 million increased $36 million compared to the same period in 2009. The increase was primarily due to increased capacity revenue and a 2010 adjustment of Ravenswood's 2009 operating costs, partially offset by the impact of a weaker U.S. dollar.

U.S. Power's Power Revenues for first quarter 2010 of $241 million decreased from $272 million for the same period in 2009 primarily due to lower realized power prices and the impact of a weaker U.S. dollar, partially offset by higher volumes of power sold.

Other Revenues of $26 million decreased $20 million in first quarter 2010 compared to the same period in 2009 due to the impact of a weaker U.S. dollar in 2010 and a decrease in revenue associated with a third-party service agreement.

Power Commodity Purchases Resold of $142 million for first quarter 2010 increased from $122 million in the same period in 2009 primarily due to an increase in the quantity of power purchased for resale under its power sales commitments, partially offset by lower contracted power prices per MWh and the impact of a weaker U.S. dollar in first quarter 2010.

Plant Operating Costs and Other of $92 million for first quarter 2010 decreased $92 million from the same period in 2009 due to the impact of a weaker U.S. dollar, decreased asset dispatch, reduced fuel costs, lower overall maintenance costs and the Ravenswood prior year adjustment.

In first quarter 2010, 95 per cent of power sales volumes were sold under contract, compared to 88 per cent for the same period in 2009. U.S. Power is focused on selling the majority of its power under contract to wholesale, commercial and industrial customers, while managing a portfolio of power supplies sourced from its own generation and wholesale power purchases. To reduce its exposure to spot market prices on uncontracted volumes, as at March 31, 2010, U.S. Power had entered into fixed-price power sales contracts to sell approximately 8,900 GWh for the remainder of 2010 and 6,600 GWh for 2011, including financial contracts to effectively lock in the margin on forecasted generation. Certain contracted volumes are dependent on customer usage levels and actual amounts contracted in future periods and will depend on market liquidity and other factors.

Comparable EBITDA excluded net unrealized losses of $28 million in first quarter 2010 resulting from changes in the fair value of certain U.S. Power derivative contracts. Power is purchased under forward contracts to satisfy a significant portion of U.S. Power's wholesale, commercial and industrial power sales commitments, mitigating its exposure to fluctuations in spot market prices and effectively locking in a positive margin. In addition, power generation is managed by entering into contracts to sell a portion of power forecasted to be generated. Contracts are entered into simultaneously to purchase the fuel required to generate the power to reduce exposure to market price volatility and effectively lock in positive margins. Each of these contracts provide economic hedges which, in some cases, do not meet the specific criteria required for hedge accounting treatment and therefore are recorded at their fair value based on forward market prices. Effective January 1, 2010, the unrealized losses from these contracts have been removed from Comparable EBITDA as they are not representative of amounts that will be realized on settlement of the contracts. Comparative amounts in 2009 were not material and therefore were not excluded from the computation of Comparable EBITDA.

Natural Gas Storage

Natural Gas Storage's Comparable EBITDA for first quarter 2010 was $51 million compared to $36 million for the same period in 2009. The $15 million increase in Comparable EBITDA in first quarter 2010 was primarily due to increased third party storage revenues as a result of higher realized seasonal natural gas price spreads. The seasonal nature of natural gas storage generally results in higher revenues in the winter season.

Comparable EBITDA excluded net unrealized losses of $21 million in first quarter 2010 (2009 – losses of $13 million) resulting from changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. TCPL manages its proprietary natural gas storage earnings by simultaneously entering into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to price movements of natural gas. Fair value adjustments recorded in each period on proprietary natural gas held in storage and these forward contracts are not representative of the amounts that will be realized on settlement. The fair value of proprietary natural gas inventory held in storage has been measured using a weighted average of forward prices for the following four months less selling costs.

Other Income Statement Items

Interest Expense

(unaudited) *(millions of dollars)*	Three months ended March 31 **2010**	2009
Interest on long-term debt[1]	**296**	335
Other interest and amortization	**32**	20
Capitalized interest	**(134)**	(54)
	194	301

(1) Includes interest for Junior Subordinated Notes.

Interest Expense decreased $107 million to $194 million in first quarter 2010 from $301 million in first quarter 2009. The decrease reflected increased capitalized interest to finance the Company's larger capital growth program in 2010, primarily due to Keystone construction. Interest expense also decreased due to the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest in first quarter 2010.

Income Taxes decreased to $97 million in first quarter 2010 from $114 million in first quarter 2009 primarily due to lower earnings in first quarter 2010.

Liquidity and Capital Resources

TCPL's financial position remains sound and consistent with recent years as does its ability to generate cash in the short and long term to provide liquidity, maintain financial capacity and flexibility, and to provide for planned growth. TCPL's liquidity position remains solid, underpinned by predictable cash flow from operations, significant cash balances on hand from common share and debt issues, as well as committed revolving bank lines of US$1.0 billion, $2.0 billion, US$1.0 billion and US$300 million, maturing in November 2010, December 2012, December 2012 and February 2013, respectively. At March 31, 2010, draws of $812 million had been made on these facilities, which also support the Company's two commercial paper programs in Canada. In addition, TCPL's proportionate share of capacity remaining available on committed bank facilities at TCPL-operated affiliates was $140 million with maturity dates from 2010 through 2012. As at March 31, 2010, TCPL had remaining capacity of $2.0 billion and US$4.0 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 of this MD&A.

At March 31, 2010, the Company held Cash and Cash Equivalents of $677 million compared to $979 million at December 31, 2009. The decrease in Cash and Cash Equivalents was primarily due to capital expenditures, partially offset by cash generated by operations.

Operating Activities

Funds Generated from Operations[1]

(unaudited) *(millions of dollars)*	Three months ended March 31 **2010**	2009
Cash Flows		
Funds generated from operations[1]	**712**	760
Decrease in operating working capital	**116**	95
Net cash provided by operations	**828**	855

(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 and Funds Generated from Operations decreased $27 million and $48 million, respectively, for the three months ended March 31, 2010 compared to the same period in 2009, primarily due to a decrease in cash generated through earnings.

Investing Activities

TCPL remains committed to executing its previously announced $22 billion capital expenditure program by the end of 2013. For the three months ended March 31, 2010, capital expenditures totalled $1.3 billion (2009 - $1.1 billion), primarily related to construction of Keystone and expenditures related to the expansion of the Alberta System, refurbishment and restart of Bruce A Units 1 and 2, and construction of Guadalajara.

Financing Activities

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

In the three months ended March 31, 2010, TCPL issued $10 million (2009 - $3.1 billion), and retired $141 million (2009 - $482 million), of Long-Term Debt while Notes Payable increased $432 million (2009 – decreased $917 million).

Dividends

On April 29, 2010, TCPL's Board of Directors declared a dividend for the quarter ending June 30, 2010, 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 June 30, 2010. The Board also declared a dividend on TCPL’s preferred shares.

TransCanada’s Board of Directors approved the issuance of common shares from treasury at a three per cent discount under TransCanada’s Dividend Reinvestment and Share Purchase Plan (DRP) for the dividends payable July 30, 2010. Under this plan, eligible TCPL preferred shareholders may reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares. TransCanada reserves the right to alter the discount or return to fulfilling DRP participation by purchasing shares on the open market at any time.

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, 2009. For further information on the Company’s accounting policies and estimates refer to the MD&A in TCPL's 2009 Annual Report.

Changes in Accounting Policies

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

Future Accounting Changes

International Financial Reporting Standards

The Canadian Institute of Chartered Accountants' (CICA) Accounting Standards Board 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. Effective January 1, 2011, the Company will begin reporting under IFRS.

TCPL continues to progress its conversion project by scheduling training sessions and IFRS updates for employees and Directors, executing changes to information systems and business processes to accommodate IFRS accounting and reporting requirements, reviewing new IFRS developments and assessing the impact that significant differences between GAAP and IFRS will have on TCPL.

TCPL currently follows specific accounting policies unique to a rate-regulated business. The Company is actively monitoring developments regarding potential future guidance on the applicability of certain aspects of rate-regulated accounting under IFRS. Developments in this area could have a significant effect on the scope of the Company's IFRS project and on TCPL's IFRS financial results. The Company is assessing the impact of developments related to the IASB's July 2009 Exposure Draft "Rate-Regulated Activities". Currently, TCPL does not expect this Exposure Draft to be effective for 2011.

TCPL actively monitors the IASB's schedule of projects, giving consideration to any proposed changes, where applicable, in its assessment of differences between IFRS and GAAP. As a result of ongoing developments related to rate-regulated accounting under IFRS as well as other areas, together with the current stage of the Company's IFRS project, TCPL cannot reasonably quantify the full impact that adopting IFRS will have on its financial position and future results.

Contractual Obligations

There have been no material changes to TCPL's contractual obligations from December 31, 2009 to March 31, 2010, 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 2009 Annual Report.

Financial Instruments and Risk Management

TCPL continues to manage and monitor its exposure to market, counterparty credit and liquidity 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, the fair value of derivative assets and loans and advances receivable. The carrying amounts and fair values of these financial assets are included in Accounts Receivable and Other in the Non-Derivative Financial Instruments Summary table below. Letters of credit and cash are the primary types of security provided to support these amounts. The majority of counterparty credit exposure is with counterparties who are investment grade. At March 31, 2010, there were no significant amounts past due or impaired.

At March 31, 2010 the Company had a credit risk concentration of $339 million due from a creditworthy counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

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

Natural Gas Inventory Price Risk

At March 31, 2010, the fair value of proprietary natural gas inventory held in storage, as measured using a weighted average of forward prices for the following four months less selling costs, was $54 million (December 31, 2009 - $73 million). The change in fair value of proprietary natural gas inventory in storage in the three months ended March 31, 2010 resulted in a net pre-tax unrealized loss of $24 million (2009 - loss of $23 million), which was recorded as a decrease to Revenues and Inventories. The net change in fair value of natural gas forward purchase and sale contracts in the three months ended March 31, 2010 resulted in a net pre-tax unrealized gain of $3 million (2009 - gain of $10 million), which was recorded as an increase to Revenues.

VaR Analysis

TCPL uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its open liquid positions. VaR represents the potential change in pre-tax earnings over a given holding period. It is calculated assuming a 95 per cent confidence level that the daily change resulting from normal market fluctuations in its open positions will not exceed the reported VaR. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR. TCPL's consolidated VaR was $6 million at March 31, 2010 (December 31, 2009 – $12 million). The decrease from December 31, 2009 was primarily due to decreased prices and lower open positions in the U.S. Power portfolio.

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At March 31, 2010, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $7.7 billion (US$7.6 billion) and a fair value of $8.0 billion (US$7.9 billion). At March 31, 2010, $158 million (December 31, 2009 - $96 million) was included in Intangibles and Other Assets for the fair value of forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

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

Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

Asset/(Liability) *(unaudited)* *(millions of dollars)*	**March 31, 2010** **Fair Value(1)**	**March 31, 2010** **Notional or Principal Amount**	December 31, 2009 Fair Value(1)	December 31, 2009 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2010 to 2014)	**140**	**U.S. 2,000**	86	U.S. 1,850
U.S. dollar forward foreign exchange contracts (maturing 2010)	**18**	**U.S. 1,030**	9	U.S. 765
U.S. dollar options (matured 2010)	**-**	**-**	1	U.S. 100
	158	**U.S. 3,030**	96	U.S. 2,715

(1) Fair values equal carrying values.

Non-Derivative Financial Instruments Summary

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

(unaudited) *(millions of dollars)*	**March 31, 2010** Carrying Amount	**March 31, 2010** Fair Value	December 31, 2009 Carrying Amount	December 31, 2009 Fair Value
Financial Assets[1]				
Cash and cash equivalents	**677**	**677**	979	979
Accounts receivable and other[2][3]	**1,365**	**1,404**	1,433	1,484
Due from TransCanada Corporation	**462**	**462**	845	845
Available-for-sale assets[2]	**22**	**22**	23	23
	2, 526	**2,565**	3,280	3,331
Financial Liabilities[1][3]				
Notes payable	**2,087**	**2,087**	1,687	1,687
Accounts payable and deferred amounts[4]	**1,633**	**1,633**	1,532	1,532
Due to TransCanada Corporation	**2,069**	**2,069**	2,069	2,069
Accrued interest	**328**	**328**	380	380
Long-term debt	**16,213**	**19,208**	16,664	19,377
Junior subordinated notes	**1,005**	**987**	1,036	976
Long-term debt of joint ventures	**931**	**1,000**	965	1,025
	24,266	**27,312**	24,333	27,046

(1) Consolidated Net Income in first quarter 2010 included losses of $7 million (2009 – losses of $14 million) for fair value adjustments related to interest rate swap agreements on US$250 million (2009 – US$200 million) of long-term debt. There were no other unrealized gains or losses from fair value adjustments to the financial instruments.

(2) At March 31, 2010, the Consolidated Balance Sheet included financial assets of $914 million (December 31, 2009 – $968 million) in Accounts Receivable, $40 million in Other Current Assets (December 31, 2009 – nil) and $433 million (December 31, 2009 - $488 million) in Intangibles and Other Assets.

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

(4) At March 31, 2010, the Consolidated Balance Sheet included financial liabilities of $1,607 million (December 31, 2009 – $1,507 million) in Accounts Payable and $26 million (December 31, 2009 - $25 million) in Deferred Amounts.

Derivative Financial Instruments Summary

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

March 31, 2010 *(unaudited)* *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Oil Products	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading(1)					
Fair Values(2)					
Assets	**$319**	**$178**	**-**	**$1**	**$26**
Liabilities	**$(251)**	**$(182)**	**-**	**$(12)**	**$(73)**
Notional Values					
Volumes(3)					
Purchases	**16,661**	**112**	**-**	**-**	**-**
Sales	**17,657**	**99**	**-**	**-**	**-**
Canadian dollars	**-**	**-**	**-**	**-**	**838**
U.S. dollars	**-**	**-**	**-**	**U.S. 612**	**U.S. 1,500**
Cross-currency	**-**	**-**	**-**	**47/U.S. 37**	**-**
Net unrealized (losses)/gains in the three months ended March 31, 2010(4)	**$(16)**	**$2**	**-**	**-**	**$(4)**
Net realized gains/(losses) in the three months ended March 31, 2010(4)	**$22**	**$(12)**	**-**	**$8**	**$(4)**
Maturity dates	**2010-2015**	**2010-2014**	**2010**	**2010-2012**	**2010-2018**
Derivative Financial Instruments in Hedging Relationships(5)(6)					
Fair Values(2)					
Assets	**$191**	**-**	**-**	**-**	**$10**
Liabilities	**$(313)**	**$(53)**	**-**	**$(48)**	**$(44)**
Notional Values					
Volumes(3)					
Purchases	**15,819**	**31**	**-**	**-**	**-**
Sales	**12,385**	**-**	**-**	**-**	**-**
U.S. dollars	**-**	**-**	**-**	**U.S. 120**	**U.S. 2,075**
Cross-currency	**-**	**-**	**-**	**136/U.S. 100**	**-**
Net realized losses in the three months ended March 31, 2010(4)	**$(7)**	**$(3)**	**-**	**-**	**$(10)**
Maturity dates	**2010-2015**	**2010-2012**	**n/a**	**2010- 2014**	**2010-2020**

(1) All derivative financial instruments in the held-for-trading classification have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

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

(4) Realized and unrealized gains and losses on power, natural gas and oil products derivative financial instruments held for trading are included in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of unrealized gains and losses on derivative financial instruments in hedging relationships are initially recognized in Other Comprehensive Income, and are reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $7 million and a notional amount of US$150 million. Net realized gains on fair value hedges for

the three months ended March 31, 2010 were $1 million and were included in Interest Expense. In first quarter 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) Net Income for the three months ended March 31, 2010 included losses of $8 million for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. There were no gains or losses included in Net Income for the three months ended March 31, 2010 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

2009 *(unaudited)* *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Oil Products	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading					
Fair Values[(1)(2)]					
Assets	$150	$107	$5	-	$25
Liabilities	$(98)	$(112)	$(5)	$(66)	$(68)
Notional Values[(2)]					
Volumes[(3)]					
Purchases	15,275	238	180	-	-
Sales	13,185	194	180	-	-
Canadian dollars	-	-	-	-	574
U.S. dollars	-	-	-	U.S. 444	U.S. 1,325
Cross-currency	-	-	-	227/ U.S. 157	-
Net unrealized gains/(losses) in the three months ended March 31, 2009[(4)]	$21	$(35)	$7	$1	-
Net realized gains/(losses) in the three months ended March 31, 2009[(4)]	$10	$26	$(3)	$6	$(4)
Maturity dates[(2)]	2010-2015	2010-2014	2010	2010-2012	2010-2018
Derivative Financial Instruments in Hedging Relationships[(5)(6)]					
Fair Values[(1)(2)]					
Assets	$175	$2	-	-	$15
Liabilities	$(148)	$(22)	-	$(43)	$(50)
Notional Values[(2)]					
Volumes[(3)]					
Purchases	13,641	33	-	-	-
Sales	14,311	-	-	-	-
U.S. dollars	-	-	-	U.S. 120	U.S. 1,825
Cross-currency	-	-	-	136/ U.S. 100	-
Net realized gains/(losses) in the three months ended March 31, 2009[(4)]	$26	$(10)	-	-	$(7)
Maturity dates[(2)]	2010-2015	2010-2014	n/a	2010-2014	2010-2020

(1) Fair values equal carrying values.

(2) As at December 31, 2009.

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

(4) Realized and unrealized gains and losses on power, natural gas and oil products derivative financial instruments held for trading are included in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of unrealized gains and losses on derivative financial instruments in hedging relationships are initially recognized in Other Comprehensive Income, and are reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $4 million and a notional amount of US$150 million at December 31, 2009. Net realized gains on fair value hedges for the three months ended March 31, 2009 were $1 million and were included in Interest Expense. In first quarter 2009, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) Net Income for the three months ended March 31, 2009 included gains of $5 million for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. There were no gains or losses included in Net Income for the three months ended March 31, 2009 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

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

(unaudited) *(millions of dollars)*	**March 31, 2010**	December 31, 2009
Current		
Other current assets	**460**	315
Accounts payable	**(538)**	(340)
Long-term		
Intangibles and other assets	**423**	260
Deferred amounts	**(438)**	(272)

Other Risks

Additional risks faced by the Company are discussed in the MD&A in TCPL's 2009 Annual Report. These risks remain substantially unchanged since December 31, 2009.

Controls and Procedures

As of March 31, 2010, an evaluation was carried out under the supervision of, and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of 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 as at March 31, 2010.

During the recent fiscal quarter, 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 2009 Annual Report, the Company's earnings outlook for 2010 has declined due to the continued negative impact of reduced market prices for power on Energy's results. For further information on outlook, refer to the MD&A in TCPL's 2009 Annual Report.

TransCanada's issuer rating assigned by Moody's Investors Service (Moody's) is Baa1 with a stable outlook. TCPL's senior unsecured debt is rated A with a stable outlook by DBRS, A3 with a stable outlook by Moody's and A- with a stable outlook by Standard and Poor's (S&P). S&P has assigned TransCanada an A- long-term corporate credit rating with a stable outlook.

Recent Developments

Pipelines

Keystone

Construction on the first phase of Keystone is substantially complete and commissioning continued in first quarter 2010. Commercial in service of this segment is expected to occur in second quarter 2010. The first phase of Keystone extends from Hardisty, Alberta to serve markets in Wood River and Patoka, Illinois and has an initial nominal capacity of 435,000 barrels per day (Bbl/d). As part of the NEB's approval to begin operations, Keystone will operate at a reduced maximum operating pressure (MOP) which will reduce throughput capacity below initial nominal capacity. Within nine months from commercial in service, Keystone is required to run additional in-line inspections on the Canadian segment of the pipeline. These inspections, any remedial work and removal of the MOP restriction are expected to be completed within this nine month period.

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

Keystone is planning to construct and operate an expansion and extension of the pipeline system that will provide additional capacity of 500,000 Bbl/d from Western Canada to the U.S. Gulf Coast in first quarter 2013. The Keystone expansion will extend from Hardisty, Alberta to a delivery point near existing terminals in Port Arthur, Texas. In March 2010, the NEB approved the Company's application to construct and operate the Canadian portion of the Keystone expansion. Permits for the U.S. portion of the expansion are expected in fourth quarter 2010. Construction of the expansion facilities is anticipated to commence in first quarter 2011 following the receipt of the remaining regulatory approvals.

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

Although commercial in service is expected to occur in second quarter 2010, TCPL expects Keystone to begin recording EBITDA in fourth quarter 2010 when the MOP restriction on the Canadian segment is expected to be removed, with EBITDA increasing through 2011, 2012 and 2013 as subsequent phases are placed in service. Based on current long-term commitments of 910,000 Bbl/d, Keystone is expected to generate EBITDA of approximately US$1.2 billion in 2013, its first full year of commercial operation serving both the U.S. Midwest and Gulf Coast markets. If volumes increase to 1.1 million Bbl/d, the full commercial design of the system, Keystone would generate approximately US$1.5 billion of annual EBITDA. In the future, Keystone can be economically expanded from 1.1 million Bbl/d to 1.5 million Bbl/d in response to additional market demand.

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

Alberta System

In March 2010, TCPL completed the final phase of the North Central Corridor natural gas pipeline. North Central Corridor consists of a 300 km (186 miles) pipeline and associated compression facilities on the northern section of the Alberta System. This project was completed ahead of schedule and under budget at a total capital cost of approximately $800 million.

In March 2010, the NEB approved TCPL's application for approval to construct and operate the Groundbirch natural gas pipeline. Construction is scheduled to commence in July 2010 with completion anticipated in November 2010. The total capital cost of this project is estimated to be $200 million.

In April 2010, the NEB announced that it will hold a public hearing process on an application TCPL filed in February 2010 for approval to construct and operate the Horn River project. The public hearing process is scheduled to begin in October 2010. Subject to regulatory approvals, the Horn River project is anticipated to commence operations in second quarter 2012 with a total capital cost of approximately $310 million.

NEB ROE Formula

In October 2009, the NEB issued a decision that the RH-2-94 Decision which has formed the basis of determining tolls for certain pipelines under NEB jurisdiction since January 1, 1995 would not continue to be in effect. The NEB stated that instead of a multi-pipeline approach, the cost of capital will be determined by negotiations between pipeline companies and their shippers or by the NEB if a pipeline company files a cost of capital application. This decision impacts certain NEB regulated pipelines including the Canadian Mainline, Alberta System, Foothills and TQM. TCPL is working with customers and interested parties to determine the cost of capital to be used in calculating tolls for 2010 on the Alberta System, Foothills and TQM. Cost of Capital discussions with stakeholders on the Canadian Mainline will commence prior to termination of its existing settlement on December 31, 2011. If agreements cannot be reached, applications will be filed with the NEB requesting an appropriate return on capital.

In November 2009, the Canadian Association of Petroleum Producers (CAPP) and the Industrial Gas Users Association (IGUA) sought leave to appeal the October 2009 NEB decision to the Federal Court of Appeal and named the NEB as the sole respondent. In March 2010, the Federal Court of Appeal dismissed the motion filed by CAPP and IGUA.

Alaska Open Season

In March 2010, the U.S. Federal Energy Regulatory Commission (FERC) approved the open season for TCPL and ExxonMobil's joint Alaska pipeline project. The open season will commence on April 30, 2010, and continue through July 30, 2010. There will be concurrent open seasons in Canada for those shippers seeking to access the pipeline in Alberta. Shippers will also have the opportunity to nominate deliveries on either the proposed pipeline to Alberta or the proposed pipeline to Valdez, Alaska. The results of the open season are expected to be available near the end of 2010.

Great Lakes Rate Case

In November 2009, the FERC commenced an investigation, alleging that, based on a review of certain historical information, Great Lakes' revenues might substantially exceed Great Lakes' actual cost of service and therefore may be unjust and unreasonable.

In April 2010, the Chief Administrative Law Judge (ALJ) granted a motion filed by Great Lakes to temporarily suspend the Great Lakes rate proceeding due to an agreement in principle which was reached among Great Lakes, active participants and the FERC trial staff. The parties anticipate filing an agreement embodying the settlement terms on or about May 17, 2010, for subsequent approval by the ALJ and the FERC. In the absence of a settlement, a hearing in the investigation is scheduled for early August 2010 and an initial decision by the ALJ is expected in November 2010. The Company does not expect the rate case settlement, if reached, will have a material effect on Great Lakes' revenues in the context of the current market environment.

Bison

In April 2010, the FERC issued a Certificate Order which requires certain submissions and approvals before approval for construction can be issued. Construction is expected to commence in second quarter 2010 with an expected in-service date of fourth quarter 2010. The project is expected to cost US$600 million.

Energy

Oakville

Advancement continues on the 900 MW Oakville power generating station located in Oakville, Ontario. In January 2010, TCPL released a draft Environmental Review Report (ERR) for government agency and public comment, with a final ERR expected to be submitted to the Province of Ontario's Ministry of the Environment in second quarter 2010. TCPL continues to work with the local community to address concerns and the project is anticipated to be in service in first quarter 2014.

Power Transmission Line Projects

TCPL continues to review the results of the open seasons on the proposed Zephyr and Chinook power transmission line projects and expects to announce the results in second quarter 2010. Each project would be capable of delivering primarily wind-generated power from Wyoming (Zephyr) and Montana (Chinook) to Nevada to access California and other U.S. desert southwest markets.

Share Information

As at April 27, 2010, TCPL had 660 million issued and outstanding common shares.

Selected Quarterly Consolidated Financial Data(1)

(unaudited)	**2010**	2009				2008		
(millions of dollars except per share amounts)	**First**	Fourth	Third	Second	First	Fourth	Third	Second
Revenues	**1,955**	2,010	2,087	2,010	2,179	2,234	2,145	2,079
Net Income	**301**	384	343	316	336	274	383	318
Share Statistics								
Net income per share – Basic and Diluted	**$0.46**	$0.58	$0.55	$0.52	$0.55	$0.47	$0.70	$0.60

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

Factors Impacting Quarterly Financial Information

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

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

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

- First quarter 2010, Energy's EBIT included net unrealized losses of $28 million pre-tax ($17 million after tax) resulting from changes in the fair value of certain U.S. Power derivative contracts. Energy's EBIT also included net unrealized losses of $21 million pre-tax ($15 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

- Fourth quarter 2009, Pipelines' EBIT included a dilution gain of $29 million pre-tax ($18 million after tax) resulting from TCPL's reduced ownership interest in PipeLines LP after PipeLines LP issued common units to the public. Energy's EBIT included net unrealized gains of $7 million pre-tax ($5 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Net Income included $30 million of favourable income tax adjustments resulting from reductions in the Province of Ontario's corporate income tax rates.

- Third quarter 2009, Energy's EBIT included net unrealized gains of $14 million pre-tax ($10 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

- Second quarter 2009, Energy's EBIT included net unrealized losses of $7 million pre-tax ($5 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Energy's EBIT also included contributions from Portlands Energy, which was placed in service in April 2009, and the negative impact of Western Power's lower overall realized power prices.

- First quarter 2009, Energy's EBIT included net unrealized losses of $13 million pre-tax ($9 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts.

- Fourth quarter 2008, Energy's EBIT included net unrealized gains of $7 million pre-tax ($6 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. Net Income included net unrealized losses of $57 million pre-tax ($39 million after tax) due to changes in the fair value of derivatives used to manage the Company's exposure to rising interest rates but which did not qualify as hedges for accounting purposes.

- Third quarter 2008, Energy's EBIT included contributions from the August 2008 acquisition of Ravenswood. Net Income included favourable income tax adjustments of $26 million from an internal restructuring and realization of losses.

- Second quarter 2008, Energy's EBIT included net unrealized gains of $12 million pre-tax ($8 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sale contracts. In addition, Western Power's EBIT increased due to higher overall realized prices and market heat rates in Alberta.

Consolidated Income

(unaudited) *(millions of dollars)*	Three months ended March 31 **2010**	 2009
Revenues	**1,955**	2,179
Operating and Other Expenses		
Plant operating costs and other	**747**	815
Commodity purchases resold	**256**	246
Depreciation and amortization	**343**	346
	1,346	1,407
Financial Charges/(Income)		
Interest expense	**194**	301
Interest expense of joint ventures	**16**	14
Interest income and other	**(24)**	(22)
	186	293
Income before Income Taxes and Non-Controlling Interests	**423**	479
Income Taxes		
Current	**80**	54
Future	**17**	60
	97	114
Non-Controlling Interests		
Non-controlling interest in PipeLines LP	**22**	24
Non-controlling interest in Portland	**3**	5
	25	29
Net Income	**301**	336
Preferred Share Dividends	**6**	6
Net Income Applicable to Common Shares	**295**	330

See accompanying notes to the consolidated financial statements.

Consolidated Cash Flows

(unaudited) *(millions of dollars)*	Three months ended March 31 **2010**	2009
Cash Generated From Operations		
Net income	**301**	336
Depreciation and amortization	**343**	346
Future income taxes	**17**	60
Non-controlling interests	**25**	29
Employee future benefits funding in excess of expense	**(32)**	(34)
Other	**58**	23
	712	760
Decrease in operating working capital	**116**	95
Net cash provided by operations	**828**	855
Investing Activities		
Capital expenditures	**(1,276)**	(1,123)
Acquisitions, net of cash acquired	**-**	(134)
Deferred amounts and other	**(216)**	(174)
Net cash used in investing activities	**(1,492)**	(1,431)
Financing Activities		
Dividends on common and preferred shares	**(266)**	(229)
Advances from/(to) parent	**383**	(8)
Distributions paid to non-controlling interests	**(21)**	(21)
Notes payable issued/(repaid), net	**432**	(917)
Long-term debt issued, net of issue costs	**10**	3,060
Reduction of long-term debt	**(141)**	(482)
Long-term debt of joint ventures issued	**8**	16
Reduction of long-term debt of joint ventures	**(26)**	(23)
Common shares issued	**-**	74
Net cash provided by financing activities	**379**	1,470
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(17)**	26
(Decrease)/Increase in Cash and Cash Equivalents	**(302)**	920
Cash and Cash Equivalents		
Beginning of period	**979**	1,300
Cash and Cash Equivalents		
End of period	**677**	2,220
Supplementary Cash Flow Information		
Income taxes paid, net of refunds	**4**	57
Interest paid	**243**	263

See accompanying notes to the consolidated financial statements.

Consolidated Balance Sheet

(unaudited) *(millions of dollars)*	**March 31, 2010**	December 31, 2009
ASSETS		
Current Assets		
Cash and cash equivalents	**677**	979
Accounts receivable	**914**	968
Due from TransCanada Corporation	**462**	845
Inventories	**463**	511
Other	**799**	701
	3,315	4,004
Plant, Property and Equipment	**34,111**	32,879
Goodwill	**3,645**	3,763
Regulatory Assets	**1,459**	1,524
Intangibles and Other Assets	**2,296**	2,500
	44,826	44,670
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable	**2,087**	1,687
Accounts payable	**2,600**	2,191
Accrued interest	**328**	380
Current portion of long-term debt	**636**	478
Current portion of long-term debt of joint ventures	**206**	212
	5,857	4,948
Due to TransCanada Corporation	**2,069**	2,069
Regulatory Liabilities	**347**	385
Deferred Amounts	**912**	743
Future Income Taxes	**2,837**	2,893
Long-Term Debt	**15,577**	16,186
Long-Term Debt of Joint Ventures	**725**	753
Junior Subordinated Notes	**1,005**	1,036
	29,329	29,013
Non-Controlling Interests		
Non-controlling interest in PipeLines LP	**686**	705
Non-controlling interest in Portland	**81**	80
	767	785
Shareholders' Equity	**14,730**	14,872
	44,826	44,670

See accompanying notes to the consolidated financial statements.

Consolidated Comprehensive Income

(unaudited) *(millions of dollars)*	Three months ended March 31 **2010**	2009
Net Income Applicable to Common Shares	**295**	330
Other Comprehensive (Loss)/Income, Net of Income Taxes		
Change in foreign currency translation gains and losses on investments in foreign operations(1)	**(147)**	(38)
Change in gains and losses on hedges of investments in foreign operations(2)	**59**	-
Change in gains and losses on derivative instruments designated as cash flow hedges(3)	**(77)**	27
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods(4)	**1**	4
Other Comprehensive (Loss)/Income	**(164)**	(7)
Comprehensive Income	**131**	323

(1) Net of income tax expense of $30 million for the three months ended March 31, 2010 (2009 - $6 million recovery).
(2) Net of income tax expense of $26 million for the three months ended March 31, 2010 (2009 - $4 million expense).
(3) Net of income tax recovery of $57 million for the three months ended March 31, 2010 (2009 - $3 million recovery).
(4) Net of income tax expense of $1 million for the three months ended March 31, 2010 (2009 - $1 million expense).

See accompanying notes to the consolidated financial statements.

Consolidated Accumulated Other Comprehensive (Loss)/Income

(unaudited) *(millions of dollars)*	Currency Translation Adjustments	Cash Flow Hedges	Total
Balance at December 31, 2009	**(592)**	**(40)**	**(632)**
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**(147)**	**-**	**(147)**
Change in gains and losses on hedges of investments in foreign operations[2]	**59**	**-**	**59**
Change in gains and losses on derivative instruments designated as cash flow hedges[3]	**-**	**(77)**	**(77)**
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[4][5]	**-**	**1**	**1**
Balance at March 31, 2010	**(680)**	**(116)**	**(796)**

Balance at December 31, 2008	(379)	(93)	(472)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	(38)	-	(38)
Change in gains and losses on hedges of investments in foreign operations[2]	-	-	-
Changes in gains and losses on derivative instruments designated as cash flow hedges[3]	-	27	27
Reclassification to net income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[4]	-	4	4
Balance at March 31, 2009	(417)	(62)	(479)

(1) Net of income tax expense of $30 million for the three months ended March 31, 2010 (2009 - $6 million recovery).
(2) Net of income tax expense of $26 million for the three months ended March 31, 2010 (2009 - $4 million expense).
(3) Net of income tax recovery of $57 million for the three months ended March 31, 2010 (2009 - $3 million recovery).
(4) Net of income tax expense of $1 million for the three months ended March 31, 2010 (2009 - $1 million expense).
(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 $68 million ($35 million, net of tax). These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

See accompanying notes to the consolidated financial statements.

Consolidated Shareholders' Equity

(unaudited) *(millions of dollars)*	Three months ended March 31 **2010**	 2009
Common Shares		
Balance at beginning of period	**10,649**	8,973
Proceeds from shares issued	**-**	74
Balance at end of period	**10,649**	9,047
Preferred Shares		
Balance at beginning and end of period	**389**	389
Contributed Surplus		
Balance at beginning of period	**335**	284
Other	**2**	2
Balance at end of period	**337**	286
Retained Earnings		
Balance at beginning of period	**4,131**	3,789
Net income	**301**	336
Common share dividends	**(275)**	(236)
Preferred share dividends	**(6)**	(6)
Balance at end of period	**4,151**	3,883
Accumulated Other Comprehensive (Loss)/Income		
Balance at beginning of period	**(632)**	(472)
Other comprehensive (loss)/income	**(164)**	(7)
Balance at end of period	**(796)**	(479)
	3,355	3,404
Total Shareholders' Equity	**14,730**	13,126

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

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

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

In preparing these financial statements, 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

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

Future Accounting Changes

International Financial Reporting Standards

The Canadian Institute of Chartered Accountants' (CICA) Accounting Standards Board 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. Effective January 1, 2011, the Company will begin reporting under IFRS.

TCPL currently follows specific accounting policies unique to a rate-regulated business. The Company is actively monitoring developments regarding potential future guidance on the applicability of certain aspects of rate-regulated accounting under IFRS. Developments in this area could have a significant effect on the scope of the Company's IFRS project and on TCPL's IFRS financial results. The Company is assessing the impact of developments related to the IASB's July 2009 Exposure Draft ''Rate-Regulated Activities''.

As a result of ongoing developments related to rate-regulated accounting under IFRS as well as other areas, together with the current stage of the Company's IFRS project, TCPL cannot reasonably quantify the full impact that adopting IFRS will have on its financial position and future results.

3. Segmented Information

Three months ended March 31	Pipelines		Energy[1]		Corporate		Total	
(unaudited)(millions of dollars)	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
Revenues	**1,129**	1,264	**826**	915	**-**	-	**1,955**	2,179
Plant operating costs and other	**(361)**	(393)	**(360)**	(409)	**(26)**	(30)	**(747)**	(832)
Commodity purchases resold	**-**	-	**(256)**	(229)	**-**	-	**(256)**	(229)
Depreciation and amortization	**(253)**	(260)	**(90)**	(86)	**-**	-	**(343)**	(346)
	515	611	**120**	191	**(26)**	(30)	**609**	772
Interest expense							**(194)**	(301)
Interest expense of joint ventures							**(16)**	(14)
Interest income and other							**24**	22
Income taxes							**(97)**	(114)
Non-controlling interests							**(25)**	(29)
Net Income							**301**	336
Preferred share dividends							**(6)**	(6)
Net Income Applicable to Common Shares							**295**	330

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

Total Assets

(unaudited) *(millions of dollars)*	**March 31, 2010**	December 31, 2009
Pipelines	**29,917**	29,508
Energy	**12,862**	12,477
Corporate	**2,047**	2,685
	44,826	44,670

4. Long-Term Debt

In the three months ended March 31, 2010, the Company capitalized interest related to capital projects of $134 million (2009 - $54 million).

5. Financial Instruments and Risk Management

TCPL continues to manage and monitor its exposure to market, counterparty credit and liquidity 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, the fair value of derivative assets and loans and advances receivable. The carrying amounts and fair values of these financial assets are included in Accounts Receivable and Other in the Non-Derivative Financial Instruments Summary table below. Letters of credit and cash are the primary types of security provided to support these amounts. The majority of counterparty credit exposure is with counterparties who are investment grade. At March 31, 2010, there were no significant amounts past due or impaired.

At March 31, 2010 the Company had a credit risk concentration of $339 million due from a creditworthy counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

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

Natural Gas Inventory Price Risk

At March 31, 2010, the fair value of proprietary natural gas inventory held in storage, as measured using a weighted average of forward prices for the following four months less selling costs, was $54 million (December 31, 2009 - $73 million). The change in fair value of proprietary natural gas inventory in storage in the three months ended March 31, 2010 resulted in a net pre-tax unrealized loss of $24 million (2009 - loss of $23 million), which was recorded as a decrease to Revenues and Inventories. The net change in fair value of natural gas forward purchase and sale contracts in the three months ended March 31, 2010 resulted in a net pre-tax unrealized gain of $3 million (2009 - gain of $10 million), which was recorded as an increase to Revenues.

VaR Analysis

TCPL uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its open liquid positions. VaR represents the potential change in pre-tax earnings over a given holding period. It is calculated assuming a 95 per cent confidence level that the daily change resulting from normal market fluctuations in its open positions will not exceed the reported VaR. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR. TCPL's consolidated VaR was $6 million at March 31, 2010 (December 31, 2009 – $12 million). The decrease from December 31, 2009 was primarily due to decreased prices and lower open positions in the U.S. Power portfolio.

Net Investment in Self-Sustaining Foreign Operations

The Company hedges its net investment in self-sustaining foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At March 31, 2010, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $7.7 billion (US$7.6 billion) and a fair value of $8.0 billion (US$7.9 billion). At March 31, 2010, $158 million (December 31, 2009 - $96 million) was included in Intangibles and Other Assets for the fair value of forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

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

Derivatives Hedging Net Investment in Self-Sustaining Foreign Operations

Asset/(Liability) *(unaudited)* *(millions of dollars)*	**March 31, 2010** Fair Value[1]	**March 31, 2010** Notional or Principal Amount	December 31, 2009 Fair Value[1]	December 31, 2009 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2010 to 2014)	**140**	**U.S. 2,000**	86	U.S. 1,850
U.S. dollar forward foreign exchange contracts (maturing 2010)	**18**	**U.S. 1,030**	9	U.S. 765
U.S. dollar options (matured 2010)	**-**	**-**	1	U.S. 100
	158	**U.S. 3,030**	96	U.S. 2,715

(1) Fair values equal carrying values.

Non-Derivative Financial Instruments Summary

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

(unaudited) *(millions of dollars)*	**March 31, 2010** Carrying Amount	**March 31, 2010** Fair Value	December 31, 2009 Carrying Amount	December 31, 2009 Fair Value
Financial Assets[1]				
Cash and cash equivalents	**677**	**677**	979	979
Accounts receivable and other [2][3]	**1,365**	**1,404**	1,433	1,484
Due from TransCanada Corporation	**462**	**462**	845	845
Available-for-sale assets[2]	**22**	**22**	23	23
	2, 526	**2,565**	3,280	3,331
Financial Liabilities[1][3]				
Notes payable	**2,087**	**2,087**	1,687	1,687
Accounts payable and deferred amounts[4]	**1,633**	**1,633**	1,532	1,532
Due to TransCanada Corporation	**2,069**	**2,069**	2,069	2,069
Accrued interest	**328**	**328**	380	380
Long-term debt	**16,213**	**19,208**	16,664	19,377
Junior subordinated notes	**1,005**	**987**	1,036	976
Long-term debt of joint ventures	**931**	**1,000**	965	1,025
	24,266	**27,312**	24,333	27,046

(1) Consolidated Net Income in first quarter 2010 included losses of $7 million (2009 – losses of $14 million) for fair value adjustments related to interest rate swap agreements on US$250 million (2009 – US$200 million) of long-term debt. There were no other unrealized gains or losses from fair value adjustments to the financial instruments.

(2) At March 31, 2010, the Consolidated Balance Sheet included financial assets of $914 million (December 31, 2009 – $968 million) in Accounts Receivable, $40 million in Other Current Assets (December 31, 2009 – nil) and $433 million (December 31, 2009 - $488 million) in Intangibles and Other Assets.

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

(4) At March 31, 2010, the Consolidated Balance Sheet included financial liabilities of $1,607 million (December 31, 2009 – $1,507 million) in Accounts Payable and $26 million (December 31, 2009 - $25 million) in Deferred Amounts.

Derivative Financial Instruments Summary

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

March 31, 2010 *(unaudited)* *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Oil Products	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading(1)					
Fair Values(2)					
Assets	**$319**	**$178**	-	**$1**	**$26**
Liabilities	**$(251)**	**$(182)**	-	**$(12)**	**$(73)**
Notional Values					
Volumes(3)					
Purchases	**16,661**	**112**	-	-	-
Sales	**17,657**	**99**	-	-	-
Canadian dollars	-	-	-	-	**838**
U.S. dollars	-	-	-	**U.S. 612**	**U.S. 1,500**
Cross-currency	-	-	-	**47/U.S. 37**	-
Net unrealized (losses)/gains in the three months ended March 31, 2010(4)	**$(16)**	**$2**	-	-	**$(4)**
Net realized gains/(losses) in the three months ended March 31, 2010(4)	**$22**	**$(12)**	-	**$8**	**$(4)**
Maturity dates	**2010-2015**	**2010-2014**	**2010**	**2010-2012**	**2010-2018**
Derivative Financial Instruments in Hedging Relationships(5)(6)					
Fair Values(2)					
Assets	**$191**	-	-	-	**$10**
Liabilities	**$(313)**	**$(53)**	-	**$(48)**	**$(44)**
Notional Values					
Volumes(3)					
Purchases	**15,819**	**31**	-	-	-
Sales	**12,385**	-	-	-	-
U.S. dollars	-	-	-	**U.S. 120**	**U.S. 2,075**
Cross-currency	-	-	-	**136/U.S. 100**	-
Net realized losses in the three months ended March 31, 2010(4)	**$(7)**	**$(3)**	-	-	**$(10)**
Maturity dates	**2010-2015**	**2010-2012**	**n/a**	**2010- 2014**	**2010-2020**

(1) All derivative financial instruments in the held-for-trading classification have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

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

(4) Realized and unrealized gains and losses on power, natural gas and oil products derivative financial instruments held for trading are included in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of unrealized gains and losses on derivative financial instruments in hedging relationships are initially recognized in Other Comprehensive Income, and are reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $7 million and a notional amount of US$150 million. Net realized gains on fair value hedges for the three months ended March 31, 2010 were $1 million and were included in Interest Expense. In first quarter 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) Net Income for the three months ended March 31, 2010 included losses of $8 million for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. There were no gains or losses included in Net Income for the three months ended March 31, 2010 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

2009
(unaudited)

(all amounts in millions unless otherwise indicated)	Power	Natural Gas	Oil Products	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading					
Fair Values(1)(2)					
Assets	$150	$107	$5	-	$25
Liabilities	$(98)	$(112)	$(5)	$(66)	$(68)
Notional Values(2)					
Volumes(3)					
Purchases	15,275	238	180	-	-
Sales	13,185	194	180	-	-
Canadian dollars	-	-	-	-	574
U.S. dollars	-	-	-	U.S. 444	U.S. 1,325
Cross-currency	-	-	-	227/ U.S. 157	-
Net unrealized gains/(losses) in the three months ended March 31, 2009(4)	$21	$(35)	$7	$1	-
Net realized gains/(losses) in the three months ended March 31, 2009(4)	$10	$26	$(3)	$6	$(4)
Maturity dates(2)	2010-2015	2010-2014	2010	2010-2012	2010-2018
Derivative Financial Instruments in Hedging Relationships(5)(6)					
Fair Values(1)(2)					
Assets	$175	$2	-	-	$15
Liabilities	$(148)	$(22)	-	$(43)	$(50)
Notional Values(2)					
Volumes(3)					
Purchases	13,641	33	-	-	-
Sales	14,311	-	-	-	-
U.S. dollars	-	-	-	U.S. 120	U.S. 1,825
Cross-currency	-	-	-	136/ U.S. 100	-
Net realized gains/(losses) in the three months ended March 31, 2009(4)	$26	$(10)	-	-	$(7)
Maturity dates(2)	2010-2015	2010-2014	n/a	2010-2014	2010-2020

(1) Fair values equal carrying values.

(2) As at December 31, 2009.

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

(4) Realized and unrealized gains and losses on power, natural gas and oil products derivative financial instruments held for trading are included in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of unrealized gains and losses on derivative financial instruments in hedging relationships are initially recognized in Other Comprehensive Income, and are reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $4 million and a notional amount of US$150 million at December 31, 2009. Net realized gains on fair

value hedges for the three months ended March 31, 2009 were $1 million and were included in Interest Expense. In first quarter 2009, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) Net Income for the three months ended March 31, 2009 included gains of $5 million for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. There were no gains or losses included in Net Income for the three months ended March 31, 2009 for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

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

(unaudited) *(millions of dollars)*	**March 31, 2010**	December 31, 2009
Current		
Other current assets	**460**	315
Accounts payable	**(538)**	(340)
Long-term		
Intangibles and other assets	**423**	260
Deferred amounts	**(438)**	(272)

Fair Value Hierarchy

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

Financial assets and liabilities measured at fair value as of March 31, 2010, including both current and non-current portions, are categorized as follows. There were no transfers between Level I and Level II in first quarter 2010.

(unaudited) *(millions of dollars, pre-tax)*	Quoted Prices in Active Markets (Level I)	Significant Other Observable Inputs (Level II)	Significant Unobservable Inputs (Level III)	Total
Natural Gas Inventory	-	54	-	54
Derivative Financial Instruments:				
Assets	137	742	19	898
Liabilities	(205)	(762)	(24)	(991)
Available-for-sale assets	22	-	-	22
Guarantee Liabilities(1)	-	-	(9)	(9)
	(46)	34	(14)	(26)

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

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

(unaudited) *(millions of dollars, pre-tax)*	Derivatives[(1)]	Guarantees[(2)]	Total
Balance at December 31, 2009	(2)	(9)	(11)
New contracts[(3)]	**(10)**	**-**	**(10)**
Settlements	**(1)**	**-**	**(1)**
Transfers out of Level III	**(5)**	**-**	**(5)**
Change in unrealized gains recorded in Net Income	**5**	**-**	**5**
Change in unrealized gains recorded in Other Comprehensive Income	**8**	**-**	**8**
Balance at March 31, 2010	**(5)**	**(9)**	**(14)**

(1) The fair value of derivative assets and liabilities is presented on a net basis.
(2) The fair value of guarantees is included in Deferred Amounts. No amounts were recognized in Net Income for the periods presented.
(3) The total amount of net losses included in Net Income attributable to derivatives that were entered into during the period and still held at the reporting date is $1 million for the three months ended March 31, 2010.

A 10 per cent increase or 10 per cent decrease in commodity prices, with all other variables held constant, would cause a $20 million decrease or a $20 million increase, respectively, in the fair value of derivative financial instruments included in Level III and outstanding as at March 31, 2010.

A 100 basis points increase or 100 basis points decrease in the letter of credit rate, with all other variables held constant, would cause a $5 million increase or a $5 million decrease, respectively, in the fair value of guarantee liabilities outstanding as at March 31, 2010. Similarly, the effect of a 100 basis points increase or 100 basis points decrease in the discount rate on the fair value of guarantee liabilities outstanding as at March 31, 2010 would cause a $1 million decrease in the liability or a $1 million increase in the liability, respectively.

6. 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 March 31	Pension Benefit Plans		Other Benefit Plans	
(unaudited)(millions of dollars)	**2010**	2009	**2010**	2009
Current service cost	**12**	11	**-**	-
Interest cost	**23**	23	**2**	2
Expected return on plan assets	**(27)**	(25)	**-**	-
Amortization of net actuarial loss	**2**	1	**-**	-
Amortization of past service costs	**1**	1	**-**	-
Net benefit cost recognized	**11**	11	**2**	2

7. Contingencies

Amounts received under the Bruce B floor price mechanism in any year are subject to repayment if spot prices exceed the floor price. With respect to 2010, 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 three months of 2010 are expected to be repaid.

8. Related Party Transactions

The following amounts are included in Due from TransCanada Corporation:

(unaudited) (millions of dollars)	Maturity Dates	2010 Outstanding December 31	2010 Interest Rate	2009 Outstanding December 31	2009 Interest Rate
Discount Notes	2010	**1,962**	**0.6 %**	1,959	0.6 %
Credit Facility		**(1,500)**	**2.3 %**	(1,114)	2.3 %
		462		845	

The following amounts are included in Due to TransCanada Corporation:

(unaudited) (millions of dollars)	Maturity Dates	2010 Outstanding December 31	2010 Interest Rate	2009 Outstanding December 31	2009 Interest Rate
Credit Facility	2012	**2,069**	**1.3 %**	2,069	1.3 %

9. Subsequent Events

Subsequent events have been assessed up to April 29, 2010, which is the date the financial statements were available for issuance.

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

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

Visit the TCPL website at: http://www.transcanada.com.