TABLE OF CONTENTS

Management's Discussion and Analysis (MD&A) dated February 14, 2011 should be read in conjunction with the accompanying audited Consolidated Financial Statements of TransCanada Corporation (TransCanada or the Company) and the notes thereto for the year ended December 31, 2010 which are prepared in accordance with Canadian generally accepted accounting principles (GAAP). This MD&A covers TransCanada's financial position and operations as at and for the year ended December 31, 2010. "TransCanada" or "the Company" includes TransCanada Corporation and its subsidiaries, unless otherwise indicated. Amounts are stated in Canadian dollars unless otherwise indicated. Abbreviations and acronyms not defined in this MD&A are defined in the Glossary of Terms in the Company's 2010 Annual Report.

TRANSCANADA OVERVIEW

With more than 50 years experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure, including natural gas and oil pipelines, power generation and natural gas storage facilities.

In pursuing its vision to be the leading energy infrastructure company in North America, TransCanada strives to execute on its portfolio of large, attractive growth projects. Each of these new projects is supported by strong business fundamentals and long-term contracts.

With assets of approximately $47 billion and a substantial growth portfolio, TransCanada believes it is well positioned to build on its track record of strong and sustainable earnings and cash flow.

At December 31, 2010, TransCanada had completed construction and placed in service, or will place in service in early 2011, approximately $10 billion of its $20 billion capital growth program. In 2010, TransCanada spent $2.3 billion to advance or complete construction of several major Natural Gas Pipeline and Energy projects, including placing five projects in service. In addition, the Company completed the first two phases of the Keystone crude oil pipeline with capital expenditures of $2.7 billion.

TransCanada's 2010 Key Accomplishments

The Company advanced a significant portion of the Keystone oil pipeline extending from Hardisty, Alberta to markets in the United States (U.S.) Midwest, including the following:

- commenced operating at a low operating pressure as the first phase of Keystone began delivering oil to Wood River and Patoka in Illinois (Wood River/Patoka) in June 2010; and
- completed construction of the extension to Cushing, Oklahoma (Cushing Extension) and commenced line fill in late 2010. The Cushing Extension was in service at the beginning of February 2011.

The Company completed construction, placed in service and advanced the following initiatives in natural gas pipelines, which included connecting new shale and unconventional natural gas supply:

- completed the final portion of the $800 million North Central Corridor (NCC) pipeline in northern Alberta in early 2010, providing capacity to shippers on the Alberta System to address increasing natural gas supply in northwestern Alberta and northeastern British Columbia (B.C.). The project was completed on schedule and under budget;
- completed the US$630 million Bison pipeline in late December 2010, delivering natural gas from the Powder River Basin in Wyoming. The pipeline was placed in service in January 2011;
- completed the $155 million Groundbirch pipeline in December 2010, on schedule and under budget, and began transporting natural gas from the Montney shale gas formation into the Alberta System;
- received approval from the National Energy Board (NEB) in January 2011 to construct the approximate $310 million Horn River natural gas pipeline, which is expected to transport natural gas from the Horn River shale gas formation starting in second quarter 2012; and
- advanced construction of the Guadalajara pipeline, which will move natural gas from Manzanillo to Guadalajara in Mexico and was 70 per cent complete as of December 31, 2010. The US$360 million project is expected to be operational in second quarter 2011.

The Company completed, placed in service and advanced the following power generation assets:

- completed the $700 million, 683 megawatt (MW) Halton Hills generating station, on time and on budget, in the fall of 2010 when it began delivering low-emission, natural gas-sourced power to the Ontario market;
- completed the US$350 million Kibby Wind project, a 44 turbine, 132 MW wind farm in Maine ahead of schedule and on budget; and
- advanced construction of the US$500 million Coolidge generation station, which is approximately 95 per cent complete, with commissioning approximately 80 per cent finished. Coolidge is anticipated to be in service in second quarter 2011.

TransCanada's Businesses Are Organized Into Three Segments – Natural Gas Pipelines, Oil Pipelines and Energy

The Natural Gas Pipelines and Oil Pipelines businesses consist of large-scale natural gas and crude oil pipelines, respectively, primarily situated in Canada and the U.S. TransCanada is also the general partner of TC PipeLines, LP (PipeLines LP), a limited partnership that owns interests in U.S. natural gas pipelines.

Natural Gas Pipelines

TransCanada's natural gas pipeline systems consist of a network of more than 60,000 kilometres (km) (37,000 miles) of wholly owned and operated natural gas pipelines, and more than 8,800 km (5,500 miles) of partially owned natural gas pipelines. The network connects major natural gas supply basins and markets, transporting approximately 20 per cent of the natural gas consumed in North America or 14 billion cubic feet (Bcf) of natural gas per day, which is delivered to local distribution companies, power generation facilities and other businesses in markets across North America. The Company's U.S. Natural Gas Pipelines also include regulated natural gas storage facilities in Michigan with a total capacity of 250 Bcf.

TransCanada is also pursuing additional natural gas pipelines projects to diversify the supply side of the business and add incremental value to existing assets. Key areas of focus include greenfield development opportunities to connect TransCanada's natural gas pipelines to emerging Canadian and U.S. shale gas and other supplies, and over the longer term, to northern natural gas reserves. TransCanada is also pursuing opportunities to optimize its existing natural gas pipelines systems to respond to the changing flow patterns of natural gas supply in North America.

Oil Pipelines

With increasing production of crude oil in Alberta and new crude oil discoveries in the U.S., including the Bakken shale play in Montana and North Dakota, along with growing demand for secure, reliable sources of energy, TransCanada has identified opportunities to develop new oil pipeline capacity. The Keystone oil pipeline complements the Company's natural gas transmission business and draws on its pipelines experience. This large-scale crude oil pipeline system, designed to initially carry 1.1 million barrels per day (Bbl/d), comprises the completed 3,467 km (2,154 miles) Wood River/Patoka and Cushing Extension phases, and a proposed 2,673 km (1,661 miles) U.S. Gulf Coast Expansion project (collectively, Keystone). Future expansions could increase the capacity of Keystone to 1.5 million Bbl/d.

Energy

TransCanada's Energy business primarily consists of a portfolio of essential power generation assets in select regions of Canada and the U.S., and unregulated natural gas storage assets in Alberta.

TransCanada owns, controls or is developing more than 10,800 MW of power generation, comprising a diverse portfolio that includes power sourced from natural gas, nuclear, coal, hydro and wind assets. TransCanada's power business is primarily located in Alberta, Ontario and Québec and in the northeastern U.S., mainly in the New England states, and New York. The assets are largely underpinned by long-term tolling contracts or represent low-cost baseload generation and essential capacity.

From offices in Western Canada, Ontario and the northeastern U.S., TransCanada complements these assets by conducting wholesale and retail electricity marketing and trading throughout North America.

In addition to power generation assets in the Energy business, TransCanada owns or controls approximately 130 Bcf of unregulated natural gas storage capacity in Alberta, or approximately one-third of all storage capacity in the province. Combined with the regulated natural gas storage in Michigan included in Natural Gas Pipelines, TransCanada provides natural gas storage and related services for approximately 380 Bcf of capacity.

TRANSCANADA'S STRATEGY

TransCanada's vision is to be the leading energy infrastructure company in North America, focusing on pipeline and power generation opportunities in regions where it has or can develop a significant competitive advantage. TransCanada's key strategies continue to evolve with the Company's growth and development and its changing business environment. TransCanada's corporate strategy integrates four fundamental value-creating activities:

1. Maximize the full-life value of TransCanada's infrastructure assets and commercial positions
2. Commercially develop and physically execute new asset investment programs
3. Cultivate a focused portfolio of high-quality development options
4. Maximize TransCanada's competitive strengths

Maximize the full-life value of TransCanada's infrastructure assets and commercial positions
TransCanada relies on a low-risk business model to maximize the full-life value of its existing assets and commercial positions. In the Natural Gas Pipelines and Oil Pipelines businesses, large-scale natural gas and crude oil pipelines connect long-life supply basins with stable and growing markets, generating predictable, sustainable cash flows and earnings of a long-term nature. In the Energy business, highly efficient, large-scale power generation facilities supply markets through long-term power purchase and sale agreements and low-volatility, shorter-term commercial arrangements. TransCanada's growing investments in natural gas, nuclear, wind and hydro-power generating facilities demonstrate the Company's commitment to sustainable, clean energy. Long-life infrastructure assets and long-term commercial arrangements will continue as cornerstones of TransCanada's business model.

Commercially develop and physically execute new asset investment programs
TransCanada's expertise, scale and financial capacity enable access to attractive commercial, financing and input cost arrangements that underpin the quality of growth projects, notably the current $20 billion capital program that began generating revenue in 2010. The remainder of these projects will provide further contributions to the Company's earnings over the next three years as they are put in service. Success in this capital program requires effective performance in engineering and in project and operational set-up and delivery. It also requires regulatory, legal and financing support. TransCanada's model for managing construction risks and maximizing capital productivity helps ensure disciplined attention to quality, cost and schedule that produces service for its customers and returns to its shareholders. Many of these functional capabilities also form the basis for successful acquisition and integration of new energy and pipeline facilities, an important dimension of the Company's growth strategy.

Cultivate a focused portfolio of high-quality development options
The Company's core regions within North America are the focus of pipelines and energy growth initiatives. TransCanada will continue to pursue opportunities to connect long-life shale and conventional natural gas resources in Western Canada, Northern Canada, Alaska, the U.S. Rockies, the U.S. midcontinent and the U.S. Gulf Coast supply regions. TransCanada will also continue to pursue opportunities to connect growing crude oil volumes from the Alberta oil sands and U.S. sources, including the Bakken formation of the Williston basin, to preferred North American markets. In addition, the Company will continue to assess energy infrastructure acquisition opportunities that complement its existing assets and provide access to new supply and market regions. In the Energy business, the Company will continue to focus on low-cost, long-life baseload power generating and natural gas storage assets supported by firm, long-term contracts with creditworthy counterparties. Selected opportunities will advance to full development and construction when market conditions are appropriate and project risks are manageable.

Maximize TransCanada's competitive strengths
TransCanada continues to build competitive strength in areas that directly drive long-term shareholder value. The Company relies on its scale, presence, operating capabilities, leadership and teams to compete effectively and deliver value to customers. A disciplined approach to capital investment combined with access to sizeable amounts of competitive-cost capital allows the Company to create shareholder value from its large capital projects. TransCanada recognizes that constructive relationships with key customers and stakeholders are critically important in the long-term energy infrastructure business.

CONSOLIDATED FINANCIAL REVIEW

SELECTED THREE-YEAR CONSOLIDATED FINANCIAL DATA

(millions of dollars except per share amounts)	**2010**	2009	2008
Income Statement			
Revenues	**8,064**	8,181	8,547
Comparable EBITDA[1]	**3,941**	4,107	4,125
Net Income	**1,272**	1,380	1,440
Preferred Share Dividends	**45**	6	–
Net Income Applicable to Common Shares	**1,227**	1,374	1,440
Comparable Earnings[1]	**1,361**	1,325	1,279
Per Share Data			
Net Income per Common Share			
Basic	**$1.78**	$2.11	$2.53
Diluted	**$1.77**	$2.11	$2.52
Comparable Earnings per Common Share[1]	**$1.97**	$2.03	$2.25
Dividends Declared			
Per Common Share	**$1.60**	$1.52	$1.44
Per Class 1 Preferred Share[2]	**$1.15**	$0.2899	–
Per Class 3 Preferred Share[2]	**$0.8041**	–	–
Per Class 5 Preferred Share[2]	**$0.6457**	–	–
Cash Flows			
Funds generated from operations[1]	**3,331**	3,080	3,021
(Increase)/decrease in operating working capital	**(249)**	(90)	135
Net Cash Provided by Operations	**3,082**	2,990	3,156
Capital Expenditures	**5,036**	5,417	3,134
Acquisitions, Net of Cash Acquired	**–**	902	3,229
Balance Sheet			
Total Assets	**46,589**	43,841	39,414
Total Long-Term Liabilities	**23,044**	21,959	20,158

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA, Comparable Earnings, Comparable Earnings per Share and Funds Generated from Operations.

(2) The Company issued Class 1, 3 and 5 preferred shares in September 2009, March 2010 and June 2010, respectively.

HIGHLIGHTS

Earnings

- Net Income was $1,272 million and Net Income Applicable to Common Shares was $1,227 million or $1.78 per share in 2010 compared to $1,380 million and $1,374 million or $2.11 per share, respectively, in 2009.
- TransCanada's Comparable Earnings of $1,361 million or $1.97 per share in 2010 excluded a $127 million after-tax valuation provision for the Mackenzie Gas Project (MGP).

Cash Flow

- Funds Generated from Operations were $3.3 billion in 2010, an increase of $0.2 billion from 2009.
- TransCanada invested $5.0 billion in its Natural Gas Pipelines, Oil Pipelines and Energy capital projects in 2010, including the following:
  - capital expenditures of $1.2 billion for Natural Gas Pipelines projects, including expansion of the Alberta System and construction of Bison and Guadalajara;
  - capital expenditures of $2.7 billion for Keystone; and
  - capital expenditures of $1.1 billion for Energy projects, including the refurbishment and restart of Bruce A Units 1 and 2, and construction of Coolidge, Halton Hills and Cartier Wind.
- In 2010, TransCanada issued approximately $2.4 billion of long-term debt, $0.7 billion of preferred shares and $0.4 billion of common shares, primarily comprising the following:
  - in September 2010, the issuance of US$1.0 billion of senior notes;
  - in June 2010, the issuance of 14 million Series 5 preferred shares at $25 per share, resulting in gross proceeds of $350 million;
  - in June 2010, the issuance of US$1.25 billion of senior notes;
  - in March 2010, the issuance of 14 million Series 3 preferred shares at $25 per share, resulting in gross proceeds of $350 million; and
  - in accordance with its Dividend Reinvestment and Share Purchase Plan (DRP), the issuance of approximately 11 million common shares from treasury in lieu of making cash dividend payments totalling $378 million.

Balance Sheet

- Total assets increased by $2.8 billion to $46.6 billion in 2010 from 2009, primarily due to investments in capital projects, described above.
- TransCanada's Shareholders' Equity increased by $1.0 billion to $16.7 billion in 2010 from 2009.

Dividends

- On February 14, 2011, the Board of Directors of TransCanada increased the quarterly dividend on the Company's outstanding common shares by five per cent to $0.42 per share from $0.40 per share for the quarter ending March 31, 2011. This was the eleventh consecutive year in which the common share dividend was increased. In addition, the Board of Directors declared quarterly dividends of $0.2875 and $0.25 per Series 1 and 3 preferred share, respectively, for the quarter ending March 31, 2011, and $0.275 per Series 5 preferred share for the three-month period ending April 30, 2011.

Refer to the Results of Operations and Liquidity and Capital Resources sections in this MD&A for further discussion of these highlights.

Reconciliation of Comparable EBITDA, Comparable EBIT, EBIT and Comparable Earnings to Net Income Applicable to Common Shares

Year ended December 31, 2010 *(millions of dollars except per share amounts)*	**Natural Gas Pipelines**	**Energy**	**Corporate**	**Total**
Comparable EBITDA[1]	**2,915**	**1,125**	**(99)**	**3,941**
Depreciation and amortization	**(977)**	**(377)**	**–**	**(1,354)**
Comparable EBIT[1]	**1,938**	**748**	**(99)**	**2,587**
Specific items:				
Valuation provision for MGP	**(146)**	**–**	**–**	**(146)**
Risk management activities	**–**	**(8)**	**–**	**(8)**
EBIT[1]	**1,792**	**740**	**(99)**	**2,433**
Interest expense				**(701)**
Interest expense of joint ventures				**(59)**
Interest income and other				**94**
Income taxes				**(380)**
Non-controlling interests				**(115)**
Net Income				**1,272**
Preferred share dividends				**(45)**
Net Income Applicable to Common Shares				**1,227**
Specific items (net of tax):				
Valuation provision for MGP				**127**
Risk management activities				**7**
Comparable Earnings[1]				**1,361**
Net Income per Share – Basic				**$1.78**
Comparable Earnings per Share[1][2]				**$1.97**

Year ended December 31, 2009 *(millions of dollars except per share amounts)*				
Comparable EBITDA[1]	3,093	1,131	(117)	4,107
Depreciation and amortization	(1,030)	(347)	–	(1,377)
Comparable EBIT[1]	2,063	784	(117)	2,730
Specific items:				
Dilution gain from reduced interest in PipeLines LP	29	–	–	29
Risk management activities	–	1	–	1
EBIT[1]	2,092	785	(117)	2,760
Interest expense				(954)
Interest expense of joint ventures				(64)
Interest income and other				121
Income taxes				(387)
Non-controlling interests				(96)
Net Income				1,380
Preferred share dividends				(6)
Net Income Applicable to Common Shares				1,374
Specific items (net of tax where applicable):				
Dilution gain from reduced interest in PipeLines LP				(18)
Risk management activities				(1)
Income tax adjustments				(30)
Comparable Earnings[1]				1,325
Net Income per Share – Basic				$2.11
Comparable Earnings per Share[1][2]				$2.03

Reconciliation of Comparable EBITDA, Comparable EBIT, EBIT and Comparable Earnings to Net Income Applicable to Common Shares

Year ended December 31, 2008 *(millions of dollars except per share amounts)*	Natural Gas Pipelines	Energy	Corporate	Total
Comparable EBITDA[1]	3,019	1,210	(104)	4,125
Depreciation and amortization	(989)	(258)	–	(1,247)
Comparable EBIT[1]	2,030	952	(104)	2,878
Specific items:				
Calpine bankruptcy distributions	279	–	–	279
GTN lawsuit settlement	17	–	–	17
Write-down of Broadwater LNG project costs	–	(41)	–	(41)
EBIT[1]	2,326	911	(104)	3,133
Interest expense				(943)
Interest expense of joint ventures				(72)
Interest income and other				54
Income taxes				(602)
Non-controlling interests				(130)
Net Income				1,440
Specific items (net of tax where applicable):				
Calpine bankruptcy distributions				(152)
GTN lawsuit settlement				(10)
Write-down of Broadwater LNG project costs				27
Income tax adjustments				(26)
Comparable Earnings[1]				1,279
Net Income per Share – Basic				$2.53
Comparable Earnings per Share[1][2]				$2.25

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

	2010	2009	2008
[2] **Comparable Earnings per Share**[1]	**$1.97**	$2.03	$2.25
Specific items – per share (net of tax where applicable):			
Valuation provision for MGP	**(0.18)**	–	–
Risk management activities	**(0.01)**	–	–
Dilution gain from reduced interest in PipeLines LP	**–**	0.03	–
Calpine bankruptcy distributions	**–**	–	0.27
GTN lawsuit settlement	**–**	–	0.02
Write-down of Broadwater LNG project costs	**–**	–	(0.05)
Income tax adjustments	**–**	0.05	0.04
Net Income per Share	**$1.78**	$2.11	$2.53

RESULTS OF OPERATIONS

TransCanada had Net Income of $1,272 million and Net Income Applicable to Common Shares of $1,227 million or $1.78 per share in 2010 compared to $1,380 million and $1,374 million or $2.11 per share, respectively, in 2009. Net Income in 2008 was $1,440 million or $2.53 per share.

Comparable Earnings in 2010, 2009 and 2008 were $1,361 million or $1.97 per share, $1,325 million or $2.03 per share and $1,279 million or $2.25 per share, respectively. Comparable Earnings in 2010 excluded a $127 million after-tax ($146 million pre-tax) valuation provision for advances to the Aboriginal Pipeline Group (APG) for the MGP. Comparable Earnings in 2010 also excluded $7 million of net unrealized after-tax losses ($8 million pre-tax) (2009 – after-tax and pre-tax gains of $1 million; 2008 – nil) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

Comparable Earnings in 2009 also excluded $30 million of favourable income tax adjustments arising from a reduction in the Province of Ontario's corporate income tax rates and an $18 million after-tax ($29 million pre-tax) dilution gain resulting from TransCanada's reduced interest in PipeLines LP after a public offering of PipeLines LP common units in fourth quarter 2009. Comparable Earnings in 2008 excluded $152 million of after-tax gains ($279 million pre-tax) on the disposition of shares received by GTN and Portland from Calpine Corporation (Calpine) bankruptcy distributions, $10 million after tax ($17 million pre-tax) of GTN lawsuit settlement proceeds and a $27 million after-tax ($41 million pre-tax) write-down of costs previously capitalized for the Broadwater liquefied natural gas (LNG) project. Comparable Earnings in 2008 also excluded $26 million of favourable income tax adjustments from an internal restructuring and realization of losses.

Comparable Earnings increased $36 million and decreased $0.06 per share in 2010 from 2009. The increase in Comparable Earnings reflected:

- decreased Comparable Earnings Before Interest and Taxes (EBIT) from Natural Gas Pipelines primarily due to the negative impact in 2010 of a weaker U.S. dollar on Natural Gas Pipelines' U.S. operations, a decrease in Canadian Mainline revenues due to decreased amounts recovered on a flow-through basis, and reduced revenues for Great Lakes. These decreases were partially offset by decreased operating, maintenance and administration (OM&A) costs, reduced depreciation expense primarily for Great Lakes, increased revenue for Northern Border and higher earnings as a result of an Alberta System revenue requirement settlement;
- decreased Comparable EBIT from Energy primarily due to lower realized power prices for Western Power and Bruce B, and lower Natural Gas Storage price spreads, partially offset by higher capacity revenues at Ravenswood and incremental earnings from the start up of Halton Hills, Portlands Energy and Kibby Wind;
- decreased Comparable EBIT loss from Corporate primarily due to lower support services and other corporate costs;
- decreased Interest Expense primarily due to an increase in capitalized interest relating to Keystone and other capital projects, the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest expense, and Canadian debt maturities, partially offset by interest expense for long-term debt issuances in 2010 and increased losses from changes in the fair value of derivatives used to manage the Company's exposure to fluctuating interest rates;
- decreased Interest Income and Other due to a higher positive impact in 2009 compared to 2010 of a weakening U.S. dollar on U.S. dollar working capital balances throughout the year;
- decreased Income Taxes due to reduced pre-tax earnings in 2010, partially offset by positive tax adjustments in 2009;
- an increase in Non-Controlling Interests due to higher PipeLines LP earnings; and
- increased preferred share dividends recorded on preferred shares issued in 2010 and third quarter 2009.

Comparable Earnings increased $46 million and decreased $0.22 per share in 2009 compared to 2008. Comparable Earnings reflected an increase in Comparable EBIT primarily as a result of higher realized power prices for Bruce Power, the positive impact in 2009 of a stronger U.S. dollar on Natural Gas Pipelines' U.S. operations, incremental earnings from the start-up of Portlands Energy and the Carleton phase of Cartier Wind, and higher earnings from the Alberta System revenue requirement settlement, partially offset by lower realized power prices in Western Power and U.S. Power, and increased costs for developing the Alaska Pipeline Project.

Net Income per Share and Comparable Earnings per Share in 2010 and 2009 were reduced by the increase in the average number of common shares outstanding following the Company's issuance of 58.4 million common shares in second quarter 2009 as well as common shares issued under the DRP. Net Income per Share and Comparable Earnings per Share in 2009 were also reduced by the issuance of 35.1 million and 34.7 million common shares in fourth quarter 2008 and second quarter 2008, respectively. The shares were issued to partially finance TransCanada's extensive capital growth program and acquisitions.

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. Natural Gas Pipelines and U.S. Energy EBIT is partially offset by U.S. dollar-denominated interest expense. The resultant net exposure is managed using derivatives, further reducing the Company's exposure to changes in U.S. foreign exchange rates.

Further discussion of these items is included in the Natural Gas Pipelines, Energy, Corporate and Other Income Statement Items sections in this MD&A.

FORWARD-LOOKING INFORMATION

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

NON-GAAP MEASURES

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

EBITDA is an approximate measure of the Company's pre-tax operating cash flow and is generally used to better measure performance and evaluate trends of individual assets. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, non-controlling interests and preferred share dividends. EBIT is a measure of the Company's earnings from ongoing operations and is generally used to better measure performance and evaluate trends within each segment. EBIT comprises earnings before deducting interest and other financial charges, income taxes, non-controlling interests and preferred share dividends.

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 year. 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, write-downs of assets and investments, and certain fair value adjustments on risk management activities. The Reconciliation of Comparable EBITDA, Comparable EBIT, EBIT and Comparable Earnings to Net Income Applicable to Common Shares table in this MD&A presents a reconciliation of Comparable Earnings, Comparable EBITDA, Comparable EBIT and EBIT to Net Income and Net Income Applicable to Common Shares. Comparable Earnings per Share is calculated by dividing Comparable Earnings by the weighted average number of common shares outstanding for the year.

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

OUTLOOK

TransCanada's corporate strategy is to maximize the full-life value of its existing assets and commercial positions, and to pursue long-term growth opportunities that add long-term shareholder value while focusing on core strengths in its pipelines and energy businesses in North America. In 2011 and beyond, TransCanada expects its net income and operating cash flow combined with a strong balance sheet and its proven ability to access capital markets will provide the financial resources needed to complete its $20 billion capital expenditure program, to continue pursuing additional long-term growth opportunities and to create additional value for its shareholders. This strategy will be executed with the same discipline and deliberate manner that characterized TransCanada's capital expenditure program in previous years. In 2011, the Company will continue to advance its capital program and implement its strategy to grow the Natural Gas Pipelines, Oil Pipelines and Energy businesses as discussed in the TransCanada's Strategy section in this MD&A.

In February 2011, TransCanada began recording EBITDA for Keystone's Wood River/Patoka and Cushing Extension phases. Keystone's EBITDA could be impacted by levels of spot volumes transported. Spot volumes transported are affected by customer demand, market pricing, refinery, terminal and pipeline facility outages, and the associated rates charged.

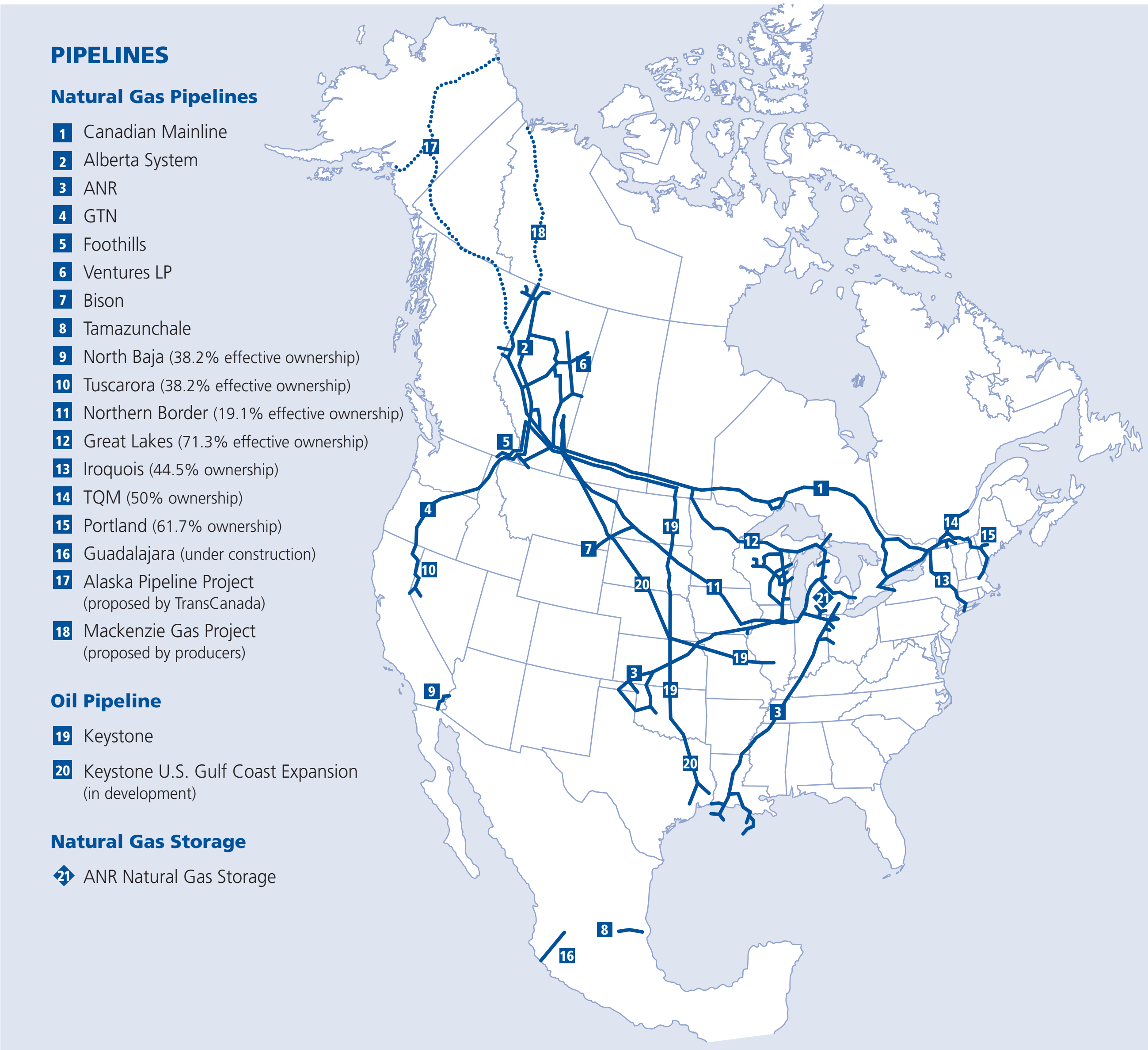
In addition, TransCanada expects a positive impact on its 2011 earnings from assets that were placed in service in 2010 and early 2011 such as NCC, Groundbirch, Bison, Halton Hills and Kibby Wind, and from assets that are expected to be placed in service later in 2011, such as Guadalajara and Coolidge. TransCanada expects that, as these new assets are placed in service in 2011, its consolidated earnings for the year will be affected by a reduction in capitalized interest and an increase in depreciation.

Natural Gas Pipelines' EBIT in 2011 may be affected by the expiry of long-term contracts, variances in throughput volume particularly on the U.S. pipelines, customer settlements and decisions made by applicable regulatory authorities.

Energy's EBIT in 2011 will be affected by the current economic climate which continues to dampen demand growth, market liquidity, as well as commodity and capacity prices. Although a significant portion of Energy's output is sold under long-term contracts, output that is sold under shorter-term forward arrangements or at spot prices will continue to be impacted by the current lower price environment. Energy's EBIT in 2011 will be positively affected by assets that were placed in service during 2010 and assets that are expected to be placed in service in 2011.

TransCanada's earnings from its U.S. Natural Gas Pipelines, Oil Pipelines and Energy businesses are generated in U.S. dollars and, therefore, fluctuations in the value of the Canadian dollar relative to the U.S. dollar can affect TransCanada's Net Income. As new assets are placed in service in the U.S., this exposure is expected to increase as EBIT from U.S. operations increases. This impact is expected to be partially offset by changes in the value of U.S. dollar-denominated interest expense. In addition, the Company expects to continue to use derivatives to manage its resultant net exposure to changes in U.S. dollar exchange rates.

The Company's results in 2011 may be affected by a number of factors and developments as discussed throughout this MD&A including, without limitation, the factors and developments discussed in the Forward-Looking Information and Business Risks sections for Natural Gas Pipelines, Oil Pipelines and Energy. Refer to the Outlook sections in this MD&A for further discussion on the outlook for Natural Gas Pipelines, Oil Pipelines and Energy.



The following pipelines are owned 100 per cent by TransCanada unless otherwise stated.

NATURAL GAS PIPELINES

CANADIAN MAINLINE The Canadian Mainline is a 14,101 km (8,762 miles) natural gas transmission system in Canada that extends from the Alberta/Saskatchewan border east to the Québec/Vermont border and connects with other natural gas pipelines in Canada and the U.S.

ALBERTA SYSTEM The Alberta System is a 24,187 km (15,029 miles) natural gas transmission system in Alberta and Northeast B.C. that connects with the Canadian Mainline and Foothills natural gas pipelines and with third-party natural gas pipelines.

ANR ANR is a 17,000 km (10,563 miles) natural gas transmission system that extends from producing fields located in the Texas and Oklahoma panhandle regions, from the offshore and onshore regions of the Gulf of Mexico, and from the U.S. midcontinent region to markets located mainly in Wisconsin, Michigan, Illinois, Indiana and Ohio. ANR also owns and operates regulated underground natural gas storage facilities in Michigan with a total working capacity of 250 Bcf.

GTN GTN is a 2,178 km (1,353 miles) natural gas transmission system that transports WCSB and Rocky Mountain-sourced natural gas to third-party natural gas pipelines and markets in Washington, Oregon and California, and connects with Tuscarora.

FOOTHILLS Foothills is a 1,241 km (771 miles) transmission system in Western Canada carrying natural gas for export from central Alberta to the U.S. border to serve markets in the U.S. Midwest, Pacific Northwest, California and Nevada.

VENTURES LP Ventures LP comprises a 161 km (100 miles) pipeline supplying natural gas to the oil sands region near Fort McMurray, Alberta and a 27 km (17 miles) pipeline supplying natural gas to a petrochemical complex at Joffre, Alberta.

BISON Bison is a 487 km (303 miles) natural gas pipeline that was placed in service in January 2011 and connects supply from the Powder River Basin in Wyoming to Northern Border in North Dakota.

TAMAZUNCHALE Tamazunchale is a 130 km (81 miles) natural gas pipeline in east central Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi.

NORTH BAJA Owned 100 per cent by PipeLines LP, North Baja is a natural gas transmission system extending 138 km (86 miles) from Ehrenberg, Arizona to Ogilby, California and connecting with a third-party natural gas pipeline system in Mexico. TransCanada operates North Baja and effectively owns 38.2 per cent of the system through its 38.2 per cent interest in PipeLines LP.

TUSCARORA Owned 100 per cent by PipeLines LP, Tuscarora is a 491 km (305 miles) pipeline system transporting natural gas from GTN at Malin, Oregon to Wadsworth, Nevada, with delivery points in northeastern California and northwestern Nevada. TransCanada operates Tuscarora and effectively owns 38.2 per cent of the system through its 38.2 per cent interest in PipeLines LP.

NORTHERN BORDER Owned 50 per cent by PipeLines LP, Northern Border is a 2,250 km (1,398 miles) natural gas transmission system serving the U.S. Midwest. TransCanada operates Northern Border and effectively owns 19.1 per cent of the system through its 38.2 per cent interest in PipeLines LP.

GREAT LAKES Owned 53.6 per cent by TransCanada and 46.4 per cent by PipeLines LP, Great Lakes is a 3,404 km (2,115 miles) natural gas transmission system serving markets in Eastern Canada and the U.S. Northeast and Midwest regions. TransCanada operates Great Lakes and effectively owns 71.3 per cent of the system through the combination of its direct ownership interest and its 38.2 per cent interest in PipeLines LP.

IROQUOIS Owned 44.5 per cent by TransCanada, Iroquois is a 666 km (414 miles) pipeline system that connects with the Canadian Mainline near Waddington, New York and delivers natural gas to customers in the northeastern U.S.

TQM Owned 50 per cent by TransCanada, TQM is a 572 km (355 miles) pipeline system that connects with the Canadian Mainline near the Québec/Ontario border, transports natural gas to markets in Québec, and connects with Portland. TQM is operated by TransCanada.

PORTLAND Owned 61.7 per cent by TransCanada, Portland is a 474 km (295 miles) pipeline that connects with TQM near East Hereford, Québec and delivers natural gas to customers in the northeastern U.S. Portland is operated by TransCanada.

TRANSGAS Owned 46.5 per cent by TransCanada, TransGas is a 344 km (214 miles) natural gas pipeline system extending from Mariquita to Cali in Colombia.

GAS PACIFICO/INNERGY Owned 30 per cent by TransCanada, Gas Pacifico is a 540 km (336 miles) natural gas pipeline extending from Loma de la Lata, Argentina to Concepción, Chile. TransCanada also has a 30 per cent ownership interest in INNERGY, an industrial natural gas marketing company based in Concepción that markets natural gas transported on Gas Pacifico.

GUADALAJARA The Guadalajara natural gas pipeline is under construction and when completed in 2011 will extend approximately 305 km (190 miles) from Manzanillo to Guadalajara in Mexico.

ALASKA PIPELINE PROJECT The Alaska Pipeline Project is a proposed natural gas pipeline and treatment plant. The pipeline would extend 2,737 km (1,700 miles) from the treatment plant at Prudhoe Bay, Alaska to Alberta. TransCanada has also proposed an alternate pipeline from Prudhoe Bay to Valdez, Alaska. TransCanada has entered into an agreement with ExxonMobil to jointly advance the project.

MACKENZIE GAS PROJECT The Mackenzie Gas Project is a proposed natural gas pipeline extending 1,196 km (743 miles) that would connect northern onshore natural gas fields with North American markets. TransCanada has the right to acquire an equity interest in the project.

OIL PIPELINE

KEYSTONE Keystone is a 3,467 km (2,154 miles) crude oil pipeline extending from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and from Steele City, Nebraska to Cushing, Oklahoma. The Wood River/Patoka and Cushing Extension phases commenced commercial operations in June 2010 and February 2011, respectively. In addition, TransCanada plans to construct the U.S. Gulf Coast Expansion, a 2,673 km (1,661 miles) extension and expansion of the pipeline to the U.S. Gulf Coast.

NATURAL GAS PIPELINES

NATURAL GAS PIPELINES – HIGHLIGHTS

- Comparable EBIT from Natural Gas Pipelines was $1.9 billion in 2010, a decrease of $0.2 billion from $2.1 billion in 2009.
- The Company invested $1.2 billion in Natural Gas Pipelines capital projects in 2010.
- Construction was completed on the Bison natural gas pipeline in late 2010 and became operational in January 2011.
- During 2010, the NEB approved the Company's Alberta System 2010 - 2012 Revenue Requirement Settlement application. The NEB also approved the Company's application for the Alberta System's Rate Design Settlement and the commercial integration of the ATCO Pipelines system with the Alberta System.
- In March 2010, the Company completed the final phase of the Alberta System's NCC expansion at a total capital cost of approximately $800 million. The Alberta System's Groundbirch pipeline was completed in December 2010 at a total capital cost of approximately $155 million.
- In December 2010, the NEB issued its decision approving the MGP subject to the project proponents meeting certain conditions and deadlines. Nevertheless, uncertainty persists with respect to the project. Accordingly, at December 31, 2010, the Company recorded a valuation provision of $146 million. TransCanada remains committed to advancing the project.
- In January 2011, the NEB approved the construction of the approximately $310 million Horn River pipeline, which is expected to commence operations in second quarter 2012.

NATURAL GAS PIPELINES – RESULTS

Year ended December 31 *(millions of dollars)*	**2010**	2009	2008
Canadian Natural Gas Pipelines			
Canadian Mainline	**1,054**	1,133	1,141
Alberta System	**742**	728	692
Foothills	**135**	132	133
Other (TQM, Ventures LP)	**50**	59	50
Canadian Natural Gas Pipelines Comparable EBITDA[1]	**1,981**	2,052	2,016
Depreciation and amortization	**(715)**	(714)	(702)
Canadian Natural Gas Pipelines Comparable EBIT[1]	**1,266**	1,338	1,314
U.S. Natural Gas Pipelines (in U.S. dollars)			
ANR	**314**	300	327
GTN[2]	**171**	170	185
Great Lakes[3]	**109**	120	118
PipeLines LP[2][4]	**99**	90	84
Iroquois	**67**	68	55
Portland[5]	**22**	22	25
International (Tamazunchale, TransGas, Gas Pacifico/INNERGY)	**42**	52	38
General, administrative and support costs[6]	**(31)**	(17)	(17)
Non-controlling interests[7]	**173**	153	161
U.S. Natural Gas Pipelines Comparable EBITDA[1]	**966**	958	976
Depreciation and amortization	**(256)**	(276)	(272)
U.S. Natural Gas Pipelines Comparable EBIT[1]	**710**	682	704
Foreign exchange	**24**	105	49
U.S. Natural Gas Pipelines Comparable EBIT[1] (in Canadian dollars)	**734**	787	753
Natural Gas Pipelines Business Development Comparable EBITDA and EBIT[1]	**(62)**	(62)	(37)
Natural Gas Pipelines Comparable EBIT[1]	**1,938**	2,063	2,030
Summary:			
Natural Gas Pipelines Comparable EBITDA[1]	**2,915**	3,093	3,019
Depreciation and amortization	**(977)**	(1,030)	(989)
Natural Gas Pipelines Comparable EBIT[1]	**1,938**	2,063	2,030
Specific items:			
Valuation provision for MGP[8]	**(146)**	–	–
Dilution gain from reduced interest in PipeLines LP[3][9]	**–**	29	–
Calpine bankruptcy distributions[10]	**–**	–	279
GTN lawsuit settlement	**–**	–	17
Natural Gas Pipelines EBIT[1]	**1,792**	2,092	2,326

(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 North Baja was sold to PipeLines LP.

(3) Represents the Company's 53.6 per cent direct ownership interest.

(4) Effective November 18, 2009, PipeLines LP's results reflected TransCanada's effective ownership in PipeLines LP of 38.2 per cent. From July 1, 2009 to November 17, 2009, TransCanada's ownership interest in PipeLines LP was 42.6 per cent. From January 1, 2008 to June 30, 2009, TransCanada's ownership interest in PipeLines LP was 32.1 per cent.

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

(6) Represents General, Administrative and Support Costs associated with certain of the Company's pipelines, including $17 million for Keystone.

(7) Non-Controlling Interests reflects Comparable EBITDA for the portions of PipeLines LP and Portland not owned by TransCanada.

(8) The Company recorded a valuation provision of $146 million for its advances to the APG for the MGP, which is discussed further under the heading Opportunities and Developments in the Natural Gas Pipelines section in this MD&A.

(9) As a result of PipeLines LP issuing common units to the public in 2009, the Company's ownership interest in PipeLines LP was reduced to 38.2 per cent from 42.6 per cent and a dilution gain of $29 million was realized.

(10) GTN and Portland received shares of Calpine with an initial value of $154 million and $103 million, respectively, as a result of the bankruptcy distributions with Calpine. These shares were subsequently sold for an additional gain of $22 million.

Natural Gas Pipelines generated Comparable EBIT of $1,938 million in 2010 compared to $2,063 million in 2009. Comparable EBIT in 2010 excluded a $146 million valuation provision for the Company's advances to the APG for the MGP. Comparable EBIT in 2009 excluded the $29 million dilution gain resulting from TransCanada's reduced interest in PipeLines LP, which occurred as a result of the public issuance of common units by PipeLines LP in November 2009. Comparable EBIT in 2008 was $2,030 million excluding the $279 million of gains received by Portland and GTN from the bankruptcy distributions with Calpine and the $17 million of proceeds received by GTN from a lawsuit settlement with a software supplier.

Wholly Owned Canadian Natural Gas Pipelines Net Income

Year ended December 31 *(millions of dollars)*	**2010**	2009	2008
Canadian Mainline	**267**	273	278
Alberta System	**198**	168	145
Foothills	**27**	23	24

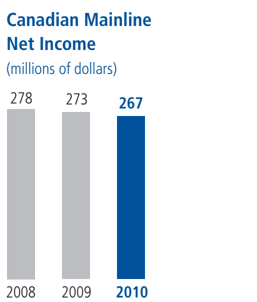
NATURAL GAS PIPELINES – FINANCIAL ANALYSIS

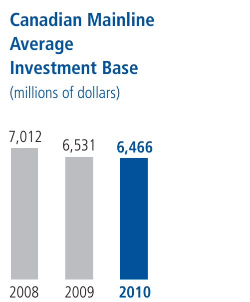
Canadian Mainline The Canadian Mainline is regulated by the NEB under the *National Energy Board Act* (Canada). The NEB sets tolls that provide TransCanada with the opportunity to recover the costs of transporting natural gas, including a return on average investment base. The Canadian Mainline's EBITDA and net income are affected by changes in investment base, the rate of return on common equity (ROE), the level of deemed common equity, potential incentive earnings and changes in the level of depreciation, financial charges and income taxes recovered in revenue on a flow-through basis.

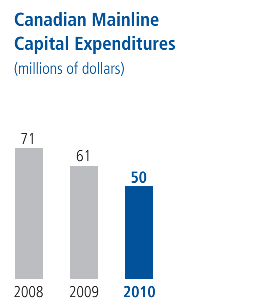
The Canadian Mainline currently operates under a five-year tolls settlement effective from 2007 through 2011. The cost of capital reflects an ROE as determined by the NEB's ROE formula on deemed common equity of 40 per cent. The tolls settlement established certain elements of the Canadian Mainline's fixed OM&A costs for each of the five years. The variance between actual and agreed-upon OM&A costs accrued entirely to TransCanada from 2007 to 2009, and was shared equally between TransCanada and its customers in 2010, and will be shared equally in 2011. All other cost elements of the revenue requirement are treated on a flow-through basis. The settlement also allows for performance-based incentive arrangements that the Company believes are mutually beneficial to TransCanada and its customers. In 2009, an adjustment charge account was established under a settlement with stakeholders and approved by the NEB to reduce tolls in 2010. In accordance with the terms of the settlement, balances in an adjustment charge account in any given year will be amortized at the composite depreciation rate and included in tolls commencing the following year.

Net income of $267 million in 2010 was $6 million lower than $273 million in 2009. The decrease was primarily the result of lower OM&A savings as a result of cost-sharing with customers and an ROE of 8.52 per cent in 2010 compared to 8.57 per cent in 2009. Net income in 2009 was $5 million lower than $278 million in 2008 as a result of a lower average investment base and lower ROE of 8.57 per cent in 2009 compared to 8.71 per cent in 2008.

Canadian Mainline's Comparable EBITDA of $1,054 million in 2010 was $79 million lower than $1,133 million in 2009, primarily due to reduced 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 affect net income. The decrease in financial charges was primarily due to higher-cost debt that matured in 2009 and early 2010. The lower income taxes in 2010 were primarily due to the adjustment charge that decreased taxable income. Comparable EBITDA in 2009 declined $8 million from $1,141 million in 2008. The decrease was primarily due to lower revenues as a result of recovery of a lower overall return on a reduced average investment base and a lower ROE in 2009. The decrease in 2009 revenues was partially offset by higher OM&A cost savings and recovery of higher depreciation.







Alberta System The Alberta System is also regulated by the NEB, which approves the Alberta System's tolls and revenue requirement. The Alberta System's EBITDA and net income are affected by changes in investment base, the ROE, the level of deemed common equity, potential incentive earnings and changes in the level of depreciation, financial charges and income taxes recovered in revenue on a flow-through basis.

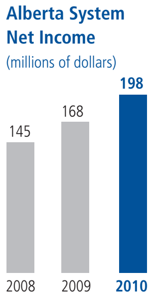
The Alberta System currently operates under the 2010 - 2012 Revenue Requirement Settlement approved by the NEB in September 2010. In October 2010, the NEB approved TransCanada's application to establish final tolls for 2010. In 2008 and 2009, the Alberta System operated under the 2008 - 2009 Revenue Requirement Settlement approved by the Alberta Utilities Commission (AUC) in December 2008. The Alberta System was regulated by the AUC until April 2009.

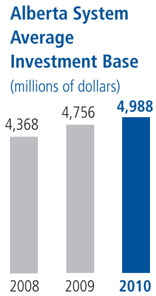
The 2010 - 2012 Revenue Requirement Settlement established an ROE of 9.70 per cent on deemed common equity of 40 per cent and included an annual fixed amount of $174 million for certain OM&A costs. Variances between actual and agreed-to OM&A costs accrue to TransCanada over the three-year term. All other cost elements of the revenue requirement are treated on a flow-through basis.

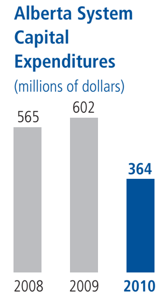
The 2008 - 2009 Revenue Requirement Settlement established fixed amounts for ROE, income taxes and certain OM&A costs. Variances between actual costs and those agreed to in the settlement accrued to TransCanada, subject to an ROE and income tax adjustment mechanism that accounted for variances between actual and settlement rate base, and income tax assumptions. The other cost elements of the settlement were treated on a flow-though basis.

The Alberta System's net income of $198 million in 2010 was $30 million higher than $168 million in 2009. The increase reflects an ROE of 9.70 per cent on 40 per cent deemed common equity in 2010 and a higher average investment base, partially offset by lower incentive earnings. Net income in 2009 was $23 million higher than $145 million in 2008 primarily due to higher settlement earnings and a higher average investment base in 2009. The increased average investment base reflected capital expenditures from 2008 to 2010 to expand capacity in response to growing customer demand for service.

The Alberta System's Comparable EBITDA of $742 million in 2010 was $14 million higher than $728 million in 2009. The increase reflects an ROE of 9.70 per cent on 40 per cent deemed common equity in 2010 and a higher average investment base, partially offset by lower incentive earnings, and lower financial charges and depreciation recovered on a flow-through basis. Comparable EBITDA in 2009 was $36 million higher than $692 million in 2008 primarily due to increased settlement earnings and a higher average investment base as well as higher revenues as a result of the recovery of higher financial charges, partially offset by lower income taxes.







Foothills Net income and Comparable EBITDA from Foothills increased $4 million and $3 million, respectively, in 2010 from 2009 primarily due to a Foothills 2010 settlement agreement, which established an ROE of 9.70 per cent on deemed common equity of 40 per cent for 2010 through 2012. Results in 2009 and 2008 were based on the NEB ROE formula of 8.57 per cent and 8.71 per cent, respectively, on deemed common equity of 36 per cent.

Other Canadian Natural Gas Pipelines Comparable EBITDA from Other Canadian Natural Gas Pipelines was $50 million in 2010 compared to $59 million in 2009. The decrease was primarily due to an adjustment in 2009 related to the NEB decision reached in March 2009 on Trans Québec and Maritimes' (TQM) cost of capital for 2007 and 2008. Comparable EBITDA in 2009 increased $9 million from $50 million in 2008, primarily due to the adjustment in 2009.

ANR American Natural Resources' (ANR) natural gas storage and transportation services are regulated by the U.S. Federal Energy Regulatory Commission (FERC) and services are provided under tariffs. These tariffs include maximum and minimum rates for services and permit ANR to discount or negotiate rates on a non-discriminatory basis. ANR Pipeline Company rates were established pursuant to a settlement approved by the FERC and became effective beginning in 1997. ANR Storage Company's rates were established pursuant to a settlement approved by the FERC and became effective beginning in 1990. None of ANR's FERC-regulated operations are required to file for new rates at any time in the future, nor are any of the operations prohibited from filing a case for new rates.

ANR's EBITDA is affected by the contracting and pricing of its existing transportation and storage capacity, expansion projects, delivered volumes and incidental natural gas sales, as well as by costs for providing various services, which include OM&A costs and property taxes. Due to the seasonal nature of its business, ANR's volumes and revenues are generally higher in the winter months.

ANR's Comparable EBITDA in 2010 was US$314 million, an increase of US$14 million compared to US$300 million in 2009, primarily due to lower OM&A costs, partially offset by lower contracted firm long-haul transportation sales and storage revenues as higher regional storage inventories and marginal supply from the U.S. Gulf Coast negatively affected transportation rates and demand for natural gas. Comparable EBITDA in 2009 decreased US$27 million compared to US$327 million in 2008. The decrease was due to lower incidental natural gas sales and higher OM&A costs, partially offset by higher transportation and storage revenues resulting from expansion projects, increased utilization and favourable pricing on existing capacity.

GTN GTN is regulated by the FERC and is operated in accordance with tariffs that establish maximum and minimum rates for various services. GTN's pipeline rates were established pursuant to a settlement approved by the FERC in January 2008. These rates were effective January 1, 2007. GTN is permitted to discount or negotiate these rates on a non-discriminatory basis. Under the settlement, a five-year moratorium commencing January 1, 2007 was established during which GTN and the settling parties are prohibited from taking certain actions, including any filings to adjust rates. The settlement also requires GTN to file for new rates that are to be in effect no later than January 1, 2014.

GTN's EBITDA is affected by variations in contracted volume levels, volumes delivered and prices charged under the various service types as well as by variations in the costs of providing services, which include OM&A costs and property taxes.

GTN's Comparable EBITDA was US$171 million in 2010, an increase of US$1 million compared to US$170 million in 2009. The increase was primarily due to lower OM&A costs and incremental proceeds accrued in 2010 relating to bankruptcy distributions with Calpine, partially offset by the impact of selling North Baja to PipeLines LP in July 2009 and the write-off of costs in 2010 related to an unsuccessful information systems project. Comparable EBITDA in 2009 decreased US$15 million, compared to US$185 million in 2008, primarily due to the sale of North Baja to PipeLines LP.

Other U.S. Natural Gas Pipelines Comparable EBITDA for the remainder of the U.S. Natural Gas Pipelines was US$481 million in 2010 and US$488 million in 2009. The decrease was primarily due to lower Great Lakes revenues, and higher general, administrative and support costs primarily related to the start-up of Keystone. Partially offsetting these decreases were increased revenues from Northern Border and higher PipeLines LP earnings in 2010 primarily due to its acquisition of North Baja in July 2009. Comparable EBITDA in 2009 increased US$24 million from US$464 million in 2008, primarily due to PipeLines LP's acquisition of North Baja.

Business Development Natural Gas Pipelines' Business Development Comparable EBITDA loss in 2010 was consistent with 2009. Comparable EBITDA losses increased to $62 million in 2009 from $37 million in 2008 primarily due to higher business development costs associated with the Alaska Pipeline Project.

Depreciation and Amortization Depreciation and Amortization for Natural Gas Pipelines was $977 million in 2010, a decrease of $53 million from $1,030 million in 2009. The decrease was primarily due to a weaker U.S. dollar in 2010 and lower depreciation for Great Lakes as a result of the lower depreciation rate in its rate settlement. Depreciation and Amortization increased $41 million to $1,030 million in 2009 from $989 million in 2008 primarily due to the stronger U.S. dollar in 2009.

NATURAL GAS PIPELINES – OPPORTUNITIES AND DEVELOPMENTS

Canadian Mainline and Alberta System 2011 Tolls In December 2010, the NEB denied TransCanada's initial interim application for 2011 tolls on the Canadian Mainline and Alberta System, which was based on a new three-year agreement with the Canadian Association of Petroleum Producers (CAPP) and was supported by CAPP and certain other stakeholders. In its decision, the NEB concluded that it was not prepared to implement significant changes to the established Canadian Mainline toll design and method of allocating costs on an interim basis, and established Canadian Mainline 2010 tolls as interim tolls for 2011. As a result, TransCanada filed for revised interim tolls on January 25, 2011 based on the existing 2007 - 2011 settlement with customers. If approved, the revised interim tolls will allow for collection of revenues that will more closely reflect TransCanada's costs and forecast throughput in 2011. TransCanada is continuing its discussions with stakeholders with the intent of increasing the level of support for a potential settlement and expects to file a subsequent application for final 2011 tolls for the Canadian Mainline.

Interim tolls for 2011 on the Alberta System were established based on the provisions of the Alberta System 2010 - 2012 Revenue Requirement Settlement approved by the NEB in 2010. TransCanada expects to file for final 2011 tolls on the Alberta System that would reflect the outcome of further discussions with stakeholders with respect to the 2011 tolls and commercial integration of the ATCO Pipelines system.

Canadian Mainline In 2010, the Canadian Mainline continued to base its return on the NEB's ROE formula in accordance with the terms of the 2007 - 2011 tolls settlement. The 2010 calculated ROE for the Canadian Mainline was 8.52 per cent, a decrease from 8.57 per cent in 2009. The NEB formula ROE in 2011 is 8.08 per cent and, pending the outcome of further discussions with stakeholders, this ROE is applicable for 2011 tolls.

Annual tolls on the Canadian Mainline are partially based on projected throughput volumes for the year. Throughput volumes for 2010 were lower than those projected when setting tolls for the year and, as a result, amounts collected through tolls were approximately 15 per cent less than anticipated in 2010. This shortfall is deferred as a Regulatory Asset for accounting purposes as it is expected to be collected in future tolls under the framework regulated by the NEB.

With the objective of maintaining markets and competitive position, TransCanada conducted two open seasons in 2010 to transport Marcellus shale gas volumes on the Canadian Mainline. These open seasons resulted in the execution of precedent agreements in January 2011 to transport a total of approximately 230,000 gigajoules of natural gas per day to eastern Canadian markets. TransCanada is assessing the facilities required to provide the requested service and will begin the work necessary to support a regulatory application in the near future.

Alberta System In September 2010, the NEB approved the Alberta System's 2010 - 2012 Revenue Requirement Settlement Application. The settlement incorporates a return of 9.70 per cent on 40 per cent deemed common equity and included an annual fixed amount of $174 million for certain OM&A costs. Variances between actual and recoverable OM&A costs accrue to TransCanada over the three-year term. All other cost elements of the revenue requirement are treated on a flow-through basis.

In August 2010, the NEB approved the Company's application for the Alberta System's Rate Design Settlement and the commercial integration of the ATCO Pipelines system with the Alberta System. This approval permits the provision of streamlined natural gas transmission service to Alberta System customers under a new rate structure that reflects the business environment. TransCanada expects commercial and operational integration of the ATCO Pipelines system and the Alberta System to be completed in third quarter 2011.

In October 2010, the NEB approved final rates for the Alberta System that reflect the 2010 - 2012 Revenue Requirement Settlement and the Rate Design Settlement. These settlements are the result of many months of collaborative work with stakeholders.

In March 2010, the final phase of the NCC natural gas pipeline was completed. The NCC consists of a 300 km (186 miles) pipeline and associated compression facilities on the northern section of the Alberta System. The NCC provides capacity to accommodate increasing natural gas supply in northwestern Alberta and northeastern B.C., increasing natural gas demand within Alberta and deliveries of natural gas to Canadian and U.S. markets. The NCC is also expected to materially reduce the quantity of fuel gas consumed by the Alberta System. This project was completed on schedule and under budget at a total capital cost of approximately $800 million.

In December 2010, the Groundbirch pipeline was completed and put in service. Groundbirch extends the Alberta System into northeastern B.C. and connects it to natural gas supplies in the Montney shale gas formation. The project was completed on schedule and under budget at a total capital cost of approximately $155 million. Groundbirch has firm transportation contracts for 1.24 Bcf/d by 2014.

In January 2011, the NEB approved construction of the Horn River pipeline, which will connect new shale gas supply in the Horn River basin north of Fort Nelson, B.C. to the Alberta System. The pipeline, costing approximately $310 million, is scheduled to be operational in second quarter 2012 and has commitments for contracted natural gas of approximately 634 million cubic feet per day (mmcf/d) by 2014.

TransCanada continues to advance further pipeline development in B.C. and Alberta to transport new gas supply. The Company has received requests for additional natural gas transmission service throughout the northwest portion of the Western Canada Sedimentary Basin (WCSB), including the Horn River and Montney areas of B.C. These new requests are expected to result in the need for further extensions and expansions of the Alberta System.

Bison Bison is a 487 km (303 miles) natural gas pipeline extending from the Powder River Basin in Wyoming and connecting to Northern Border in North Dakota. The pipeline has shipping commitments for approximately 407 mmcf/d and was placed in service in January 2011. The capital cost of Bison was US$630 million.

Mexico In 2010, TransCanada began construction on the US$360 million Guadalajara pipeline in Mexico, which is supported by a 25-year contract for its entire capacity with the Comisión Federal de Electricidad, Mexico's state-owned electric power company. Guadalajara is a natural gas pipeline of approximately 305 km (190 miles) extending from Manzanillo to Guadalajara. The pipeline has an expected in-service date of mid-2011 and was 70 per cent complete at December 31, 2010. TransCanada continues to pursue additional opportunities in Mexico, including the extension or expansion of existing assets.

Great Lakes In November 2009, the FERC issued an order instituting an investigation pursuant to Section 5 of the *Natural Gas Act* (Rate Proceeding). The FERC alleged, based on a review of certain historical information, that Great Lakes' revenues might substantially exceed its actual cost of service and, therefore, may be unreasonable. In July 2010, the FERC approved, without modification, a settlement reached among Great Lakes, active participants and the FERC trial staff establishing the terms pursuant to which all matters in the Rate Proceeding would be resolved. As approved, this settlement applies to all current and future shippers on the Great Lakes system.

Under the terms of the settlement, Great Lakes' reservation rates were reduced by eight per cent and annual depreciation expense for Great Lakes' transmission plant were decreased to a rate of 1.48 per cent from a rate of 2.75 per cent. Depreciation rates for other assets decreased or remained unchanged. Rates for interruptible transportation services increased approximately 28 per cent. All terms of the settlement were effective May 1, 2010.

Under the terms of the settlement, Great Lakes' obligation to share interruptible transportation revenues with its shippers was eliminated effective May 1, 2010. Great Lakes also agreed to a new revenue-sharing provision whereby it will share with qualifying shippers 50 per cent of any qualifying revenues collected in excess of US$500 million between November 1, 2010 and October 31, 2012.

ANR In 2010, ANR connected new sources of natural gas supply from emerging production plays located in the Texas and Oklahoma panhandle regions and connected with new pipelines from shale gas supply in the U.S midcontinent. ANR is focused on attracting and connecting to additional natural gas supply directly or through new pipeline interconnects and on connecting to new or growing markets, particularly in the U.S. Midwest where natural gas-fired electric generation demand is expected to increase over the next several years.

In September 2008, certain portions of ANR's Gulf of Mexico offshore facilities were damaged by Hurricane Ike. The Company estimates its total exposure to damage costs to be approximately US$40 million to US$50 million, mainly to replace, repair and abandon capital assets, including the estimated cost to abandon an offshore platform. Since September 2008, related capital expenditures of US$13 million (2009 – US$11 million) and OM&A costs of US$9 million (2009 – US$7 million) have been incurred. The remaining costs are expected to be incurred primarily in 2011 and 2012. Service on the offshore facilities and related throughput volumes are at pre-hurricane levels.

TQM In December 2010, the NEB approved TQM's final tolls for 2010 and interim tolls for 2011. These final and interim tolls reflect the terms of an NEB-approved multi-year settlement with TQM's interested parties regarding its annual revenue requirement for 2010 to 2012. The settlement includes an annual revenue requirement comprising fixed and flow-through components. The fixed component includes certain OM&A costs, return on rate base, depreciation and municipal taxes, with variances from actual costs accruing to TQM. In June 2010, the NEB approved TQM's final 2009 tolls based on a 6.4 per cent after-tax weighted average cost of capital on rate base and all the cost components in an NEB-approved three-year partial settlement for 2007 to 2009.

Alaska Pipeline Project The proposed Alaska Pipeline Project is a 4.5 Bcf/d natural gas pipeline extending 2,737 km (1,700 miles) from a proposed new natural gas treatment plant at Prudhoe Bay, Alaska to Alberta. The pipeline would provide access to diverse markets across North America and is expected to have an estimated capital cost of US$32 billion to US$41 billion. The pipeline construction application filed by TransCanada included provisions to expand capacity to 5.9 Bcf/d through the addition of compressor stations in Alaska and Canada. The estimated capital cost for the project is an increase over previous estimates. The latest estimate is based on increased costs for oil and gas projects from 2007 to 2009 and a significant increase in the estimated cost of building the gas treatment plant at Prudhoe Bay. TransCanada has also proposed an alternate pipeline from Prudhoe Bay to Valdez, Alaska to supply LNG markets. The estimated capital cost of the alternate pipeline is US$20 billion to US$26 billion. TransCanada has entered into an agreement with ExxonMobil to jointly advance the project. A joint project team is developing the engineering, environmental, aboriginal relations and commercial components of the project.

The State of Alaska has issued TransCanada a license to construct the Alaska Pipeline Project under the *Alaska Gasline Inducement Act* (AGIA). The state determined that TransCanada's application to construct a pipeline under the AGIA was the only proposal that met all of the state's requirements. Under the AGIA, the State of Alaska has agreed to reimburse a share of TransCanada's eligible pre-construction costs, as they are incurred, subject to approval by the state, to a maximum of US$500 million. The State of Alaska reimbursed up to 50 per cent of the eligible costs incurred prior to the close of the first binding open season on July 30, 2010. Commencing July 31, 2010, the state began reimbursing up to 90 per cent of the eligible costs. The reimbursements and project-applicable expenses are shared proportionately with ExxonMobil. In 2010, the Company expensed $34 million related to the project.

On July 30, 2010, the Alaska Pipeline Project concluded its initial open season. The project team continues to work with shippers to resolve the conditions under its control.

Palomar In December 2008, Palomar Gas Transmission LLC applied to the FERC for a certificate to build a 349 km (217 miles) natural gas pipeline extending from GTN in central Oregon to the Columbia River northwest of Portland. The proposed pipeline would have a capacity of up to 1.3 Bcf/d of natural gas and would be a 50/50 joint venture between GTN and Northwest Natural Gas Co. In May 2010, an underpinning shipper filed a bankruptcy proceeding and subsequently terminated its transportation agreement with Palomar. The partners of Palomar continue to support the project and are engaged in discussions with potential shippers to secure additional shipping commitments for the proposed pipeline.

Mackenzie Gas Project The MGP is a proposed 1,196 km (743 miles) natural gas pipeline extending from a point near Inuvik, Northwest Territories to the northern border of Alberta, where it would connect to the Alberta System.

TransCanada's involvement with the MGP arises from a 2003 agreement between the Mackenzie Valley APG and the MGP, under which TransCanada agreed to finance the APG's one-third share of the pre-development costs associated with the project. Under the terms of certain MGP agreements, TransCanada holds an option to acquire up to five per cent equity ownership in the MGP at the time of the decision to construct it. In addition, TransCanada gained certain rights of first refusal to acquire 50 per cent of any divestitures by existing partners and an entitlement to obtain a one-third interest in all expansion opportunities once the APG reaches a one-third ownership share, with the other natural gas pipeline owners and the APG sharing the balance.

At December 31, 2010, the Company had advanced $146 million (2009 – $143 million) on behalf of the APG. These advances constituted a loan to the APG, which would become repayable only after the natural gas pipeline commenced commercial operations. If the project does not proceed, TransCanada has no recourse against the APG for recovery of advances made.

The MGP proponents continue to pursue the required regulatory approvals for the project and the Canadian government's support of an acceptable fiscal framework. In December 2010, the NEB released a decision granting approval of the project's application for a Certificate of Public Convenience and Necessity. The approval contained 264 conditions including the requirement to file an updated cost estimate and report on the decision to construct by the end of 2013 and, further, that construction must commence by December 31, 2015.

Nevertheless, uncertainty persists with respect to the project's ultimate commercial structure and fiscal framework, the timeframes under which the project would proceed and if and when the Company's advances to the APG will be repaid. Accordingly, at December 31, 2010, TransCanada recorded a valuation provision for its $146 million loan to the APG. Future amounts advanced to the APG in furtherance of the MGP will be expensed. TransCanada remains committed to advancing the project.

NATURAL GAS PIPELINES – BUSINESS RISKS

Natural Gas Supply, Markets and Competition TransCanada faces competition at both the supply and market ends of its natural gas pipeline systems. This competition comes from other natural gas pipelines accessing supply basins, including the WCSB, and markets served by TransCanada's pipelines as well as from natural gas supplies produced in basins not directly served by the Company. Growth in supply and pipeline infrastructure has increased competition throughout North America. Production has increased in the U.S., driven primarily by shale gas, while WCSB and other natural gas basin production has declined. Lower-cost shale gas in the U.S. has resulted in an increase in competition between supply basins, changes to traditional flow patterns and an increase in choices for customers. This change has contributed to a continued reduction in long-haul, long-term firm contracted capacity and a shift to shorter-distance, short-term firm and interruptible contracts on natural gas pipelines.

Although TransCanada has diversified its natural gas supply sources, many of its North American natural gas pipelines and its transmission infrastructure remain dependent on supply from the WCSB. The WCSB has established natural gas reserves of approximately 60 trillion cubic feet and a reserves-to-production ratio, based on these established reserves, of approximately 11 years at current levels of production. The reserves-to-production ratio is a measure of drilling and production activity that can increase or deplete reserves. Historically, this factor has been unchanged at approximately nine years. More recently, it has increased to 11 years as production from the WCSB has declined due to reduced drilling activity in the basin. The reduced drilling activity is a result of lower prices, higher supply costs and competition for capital from other North American gas production basins that have lower exploration costs. Drilling levels in the WCSB are expected to recover in the future, assuming natural gas prices increase and finding and development costs continue to improve. As part of the Alberta government's competitiveness review, the existing oil and gas royalty framework was substantially revamped. These changes are expected to increase investment in the WCSB, which should also support increased activity levels. TransCanada expects there will be excess natural gas pipeline capacity from the WCSB to markets outside Alberta for the foreseeable future as a result of capacity expansions on natural gas pipelines over the past decade, competition from other pipelines and supply basins, and significant growth in natural gas consumption within Alberta driven primarily by oil sands and electricity generation requirements.

TransCanada's Alberta System is the major natural gas gathering and transportation system for the WCSB, connecting most of the natural gas processing plants in Western Canada to domestic and export markets. Despite reduced overall drilling levels, increased drilling rates in certain areas of the WCSB have resulted in the need for new natural gas transmission infrastructure. Drilling activity has increased in northwestern Alberta and northeastern B.C. as producers develop projects to access deeper multi-zone reserves, unconventional gas shale and tight sands utilizing horizontally-drilled wells in combination with multi-stage hydraulic fracturing stimulation techniques. Recently, shale gas production in northeastern B.C. has emerged as a significant natural gas supply source. TransCanada forecasts approximately 5 Bcf/d of total production from the Montney and Horn River shale gas sources by 2020, however, achieving this level will depend on natural gas prices as well as producer economics in the basin. The production from these two natural gas zones is approximately 1 Bcf/d. TransCanada recently commissioned the Groundbirch pipeline, its first B.C. pipeline extension to serve the Montney shale gas formation. In addition, the Company received approval in January 2011 to construct a major extension of its Alberta System that will allow emergent unconventional B.C. gas production from the Horn River shale gas formation to be transported to markets served by TransCanada's pipeline systems.

Demand for WCSB-sourced natural gas in Eastern Canada and the U.S. Northeast decreased in 2010, largely as a result of a diversification of supply sources. However, demand for natural gas in TransCanada's key eastern markets served by the Canadian Mainline is expected to increase over time, particularly to meet the expected growth in natural gas-fired power generation. There are opportunities to increase market share in Canadian domestic and U.S. export markets, however, TransCanada expects to continue to face significant competition in these markets. Consumers in the northeastern U.S. generally have access to an array of natural gas pipeline and supply options. Eastern markets that historically received Canadian supplies only from TransCanada's systems are now able to receive supplies from new natural gas pipelines that source U.S. and Atlantic Canada supplies. In recent years, the Canadian Mainline has experienced reductions in volumes originating at the Alberta border and in Saskatchewan, which have been partially offset by increases in volumes originating at points east of Saskatchewan. These reductions in both volumes and distance transported have resulted in an increase in Canadian Mainline tolls that adversely affects its competitive position.

ANR's directly connected natural gas supply is primarily sourced from the U.S. Gulf Coast and midcontinent regions which are also served by competing interstate and intrastate natural gas pipelines. The U.S. Gulf Coast is highly competitive given its extensive natural gas pipeline network. ANR is one of many pipelines competing for new and existing production in this region. ANR must also compete for interconnects with and supply from pipelines originating within the growing U.S. midcontinent shale gas formations and the Rocky Mountain production regions.

ANR competes for market share with other natural gas pipelines and storage operators in its primary markets in the U.S. Midwest. Lower natural gas prices could reduce drilling activity and reduce the supply growth that has been fuelling the expansion of pipeline infrastructure in the U.S. midcontinent. As transportation capacity becomes more abundant, lower natural gas prices and supply could negatively affect the value of pipeline capacity. ANR's natural gas storage is primarily contracted on a relatively short-term basis and the value of storage services is based on market conditions, which could become unfavourable resulting in reduced rates and terms.

GTN is primarily supplied with natural gas from the WCSB and competes with other interstate pipelines providing natural gas transportation services to markets in the U.S. Pacific Northwest, California and Nevada. These markets also have access to supplies from natural gas basins in the Rocky Mountains and the U.S. Southwest. Historically, natural gas supplies from the WCSB have been competitively priced against supplies from the other regions serving these markets. Increased competing supply sources could negatively affect the transportation value on GTN. Pacific Gas and Electric Company, GTN's largest customer, received California Public Utilities Commission approval to commit to capacity on a competing pipeline project out of the Rocky Mountain basin to the California border. The owner of this competing pipeline has announced it is expected to be in service in 2011.

Regulatory Risk Regulatory decisions continue to have an impact on the financial returns from existing investments in TransCanada's Canadian natural gas pipelines and are expected to have a similar impact on financial returns from future investments. Through rate applications and negotiated settlements, TransCanada has been able to improve the financial returns of its Canadian natural gas pipeline and their capital structures.

Regulations and decisions issued by U.S. regulatory bodies, particularly the FERC, Environmental Protection Agency (EPA) and Department of Transportation, may have an impact on the financial performance of TransCanada's U.S. pipelines. TransCanada continually monitors existing and proposed regulations to determine their possible impact on its U.S. pipelines.

Throughput Risk As transportation contracts expire, TransCanada expects its U.S. natural gas pipelines to become more exposed to the risk of reduced throughput and their revenues to become more likely to experience increased variability. Throughput risk is created by supply and market competition, variations in economic activity, weather variability, natural gas pipeline competition and pricing of alternative fuels.

Refer to the Risk Management and Financial Instruments section in this MD&A for information on additional risks and managing risks in the Natural Gas Pipelines business.

NATURAL GAS PIPELINES – OUTLOOK

The Company expects demand for natural gas in North America to increase in the long term, although demand growth is expected to continue to be relatively weak in 2011. TransCanada's Natural Gas Pipelines business will continue to focus on delivering natural gas to growing markets, connecting new supply and progressing development of new infrastructure to connect with natural gas from unconventional supplies such as shale gas, coalbed methane and LNG, and from the north.

Reduced throughput and greater use of shorter-distance transportation contracts are the primary factors that continue to put pressure on the Canadian Mainline to increase its tolls. This situation, coupled with the ongoing development and growth of competitive alternative natural gas supply from infrastructure in U.S. shale gas regions, is increasing competitive pressures on the Canadian Mainline. In response, TransCanada continues to work closely with its stakeholders, examining the Canadian Mainline's rate design, business model and available services to develop solutions that would result in higher throughput and revenue as well as lower costs and tolls. TransCanada is also pursuing the connection of new sources of U.S. natural gas supply from the Marcellus shale gas formation to the Canadian Mainline infrastructure to enhance its current markets and competitive position.

TransCanada will continue to focus on operational excellence and collaboration with all stakeholders to achieve negotiated settlements and provision of services that will increase the value of the Company's business.

Most of TransCanada's expansion plans in Canadian natural gas transmission are focused on the Alberta System. TransCanada is actively involved in expanding the Alberta System to serve the growing shale gas regions in northeastern B.C. Additional growth opportunities for the Alberta System include the west and central foothills regions of Alberta.

In the U.S., TransCanada expects unconventional production will continue to be developed from shale gas formations in eastern Texas, northwestern Louisiana, Arkansas, southwestern Oklahoma and the Appalachian Mountain region. Production focus has shifted in the near term toward more oil and hydrocarbon-rich production, which is expected to increase natural gas supply in Texas and North Dakota. Supply from coalbed methane and tight gas sands in the Rocky Mountain region is also expected to grow. The resulting anticipated growth in U.S. supply should provide additional opportunities for TransCanada's U.S. pipelines.

Earnings Canadian Natural Gas Pipelines' earnings are affected by changes in investment base, ROE, capital structure and terms of toll settlements as approved by the NEB, with the most significant variables being ROE, capital structure and investment base. The Company expects continued growth of the Alberta System investment base as new supply in northeastern B.C. continues to be developed and connected to the Alberta System. TransCanada also anticipates a modest level of investment in its other Canadian natural gas pipelines but expects a continued net decline in the average investment bases of these pipelines as annual depreciation outpaces capital investment. A net decline in the average investment base would have the effect of reducing year-over-year earnings from these assets. Under the current regulatory model, earnings from Canadian natural gas pipelines are not affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contract levels.

The in service of Bison in January 2011 and the expected in service of Guadalajara in mid-2011 will positively impact earnings of U.S. Natural Gas Pipelines. The ability to recontract available capacity at attractive rates is influenced by prevailing market conditions and competitive factors, including competing natural gas pipelines and supply from other natural gas sources in markets served by TransCanada's U.S. pipelines. EBIT from U.S. Natural Gas Pipelines' operations is also affected by the level of OM&A costs, regulatory decisions and changes in foreign currency exchange rates.

In addition, Natural Gas Pipelines' EBIT is expected to be affected by costs to develop new pipeline projects, including the Alaska Pipeline Project.

Capital Expenditures Total capital spending for natural gas pipelines was $1.2 billion in 2010. Capital spending for the Company's wholly owned pipelines is expected to be approximately $1.1 billion in 2011.

NATURAL GAS THROUGHPUT VOLUMES *(Bcf)*	**2010**	2009	2008
Canadian Mainline[1]	**1,666**	2,030	2,173
Alberta System[2]	**3,447**	3,538	3,800
ANR	**1,589**	1,575	1,619
Foothills	**1,446**	1,205	1,292
Northern Border[3]	**902**	706	839
Great Lakes	**804**	727	784
GTN	**802**	797	783
Iroquois	**343**	355	376
TQM	**151**	164	170
Ventures LP	**144**	145	165
North Baja	**60**	96	104
Tamazunchale	**52**	54	53
Gas Pacifico	**51**	62	73
Portland	**36**	37	50
Tuscarora[3]	**35**	34	30
TransGas	**30**	28	26

(1) Canadian Mainline's throughput volumes reflect physical deliveries to domestic and export markets. Customer contracting patterns have changed in recent years therefore the Company uses physical deliveries to measure system utilization. Canadian Mainline physical receipts originating at the Alberta border and in Saskatchewan in 2010 were 1,228 Bcf (2009 – 1,579 Bcf; 2008 – 1,898 Bcf).

(2) Field receipt volumes for the Alberta System in 2010 were 3,471 Bcf (2009 – 3,578 Bcf; 2008 – 3,843 Bcf).

(3) Throughput volumes for Northern Border and Tuscarora reflect scheduled deliveries. Throughput volumes in previous years reflected physical deliveries.

OIL PIPELINES

OIL PIPELINES – HIGHLIGHTS

- The Company invested $2.7 billion in 2010 to advance Keystone.
- The first phase of Keystone extending from Hardisty, Alberta to Wood River and Patoka in Illinois began operating at a low operating pressure in June 2010.
- The second phase extending Keystone from Steele City, Nebraska to Cushing, Oklahoma was placed in service at the beginning of February 2011.

OIL PIPELINES – FINANCIAL ANALYSIS

Although the first phase of Keystone extending from Hardisty, Alberta to Wood River and Patoka in Illinois commenced commercial operations in June 2010, cash flows related to Keystone, other than general, administrative and support costs, were capitalized during 2010. As a condition of the NEB's approval to begin operations, Wood River/Patoka was operating at a reduced maximum operating pressure (MOP) on the Canadian conversion segment of the pipeline, which did not allow the pipeline to run at design pressure and reduced throughput capacity below the initial nominal capacity of 435,000 Bbl/d. After additional in-line inspections were completed, the NEB removed the MOP restriction in December 2010 and the required operational modifications were completed in late January 2011. As a result, the system began operating at design pressure and the Company commenced recording EBITDA for Keystone at the beginning of February 2011.

OIL PIPELINES – OPPORTUNITIES AND DEVELOPMENTS

Keystone The Cushing Extension extends the pipeline to Cushing, Oklahoma and increases nominal capacity to 591,000 Bbl/d if design capacity is achieved. The extension began commissioning in late 2010 and commenced commercial in service at the beginning of February 2011.

After an open season conducted in 2008, Keystone secured additional firm, long-term shipper contracts to expand and extend the system. With these commitments, Keystone filed the necessary regulatory applications in Canada and the U.S. for approval to construct and operate the U.S. Gulf Coast Expansion from Western Canada to the U.S. Gulf Coast, which would provide additional pipeline capacity. In March 2010, the NEB approved the application for the new Canadian facilities required for the U.S. Gulf Coast Expansion. In April 2010, the Department of State, the lead agency for U.S. federal regulatory approvals, issued a Draft Environmental Impact Statement which concluded that the U.S. Gulf Coast Expansion would have limited environmental impact. The regulatory process conducted by the Department of State is continuing within a heightened political environment and opposition to the project has been expressed. However, the Company expects a decision regarding final regulatory approvals in mid to late 2011. Construction on the U.S. Gulf Coast Expansion is expected to begin shortly thereafter.

The capital cost of Keystone, including the U.S. Gulf Coast Expansion, is estimated to be approximately US$13 billion. The US$1 billion increase from the previously estimated capital cost of approximately US$12 billion reflects currency translation, an increase in the actual cost incurred bringing the Wood River/Patoka and Cushing Extension phases to commercial in service and an increase in estimated capital cost associated with the U.S. Gulf Coast Expansion resulting from scope changes, evolving regulatory requirements and permitting delays. At December 31, 2010, US$7.4 billion had been invested, including US$1.4 billion related to the U.S. Gulf Coast Expansion. The remaining US$5.6 billion, US$1.2 billion of which has already been committed, is expected to be invested between now and the in-service date of the expansion, which is expected in 2013. Capital costs related to the construction of Keystone are subject to capital cost risk- and reward-sharing mechanisms with Keystone's long-term committed shippers.

In August 2009, TransCanada purchased ConocoPhillips' remaining interest in Keystone. The purchase gave TransCanada 100 per cent ownership of Keystone.

Three entities, each of which had entered into Transportation Service Agreements for the Cushing Extension, have filed separate Statements of Claim against certain of TransCanada's Keystone subsidiaries in the Alberta Court of Queen's Bench, seeking declaratory relief, or alternatively, damages in varying amounts. One of the claims has been discontinued on a without-cost and without-liability basis. The Company believes the remaining claims to be without merit and will vigorously defend against them.

Marketlink Projects The Company is pursuing opportunities to transport growing Bakken shale crude oil production from the Williston Basin in Montana and North Dakota to major U.S. refining markets. Following an open season conducted in the second half of 2010, the Company secured firm, five-year shipper contracts totalling 65,000 Bbl/d for its proposed Bakken Marketlink project, which would transport U.S. crude oil from Baker, Montana to Cushing on facilities that form part of the Keystone U.S. Gulf Coast Expansion. With these commitments, TransCanada will file for the necessary regulatory approvals in the U.S. to construct and operate the Bakken Marketlink project. The capital cost of the incremental facilities is expected to be approximately US$140 million and commercial in service is anticipated in 2013.

Following an open season conducted in the second half of 2010, the Company secured contractual support to proceed with the Cushing Marketlink project, which would transport up to 150,000 Bbl/d of crude oil from Cushing to the U.S. Gulf Coast on facilities that form part of the U.S. Gulf Coast Expansion. With these commitments, TransCanada will file for the necessary regulatory approvals in the U.S. to construct and operate the Cushing Marketlink project. Commercial in service is anticipated in 2013.

OIL PIPELINES – BUSINESS RISKS

Crude Oil Supply, Markets and Competition Alberta produces approximately 80 per cent of the crude oil in the WCSB and is the primary source of crude oil supply for Keystone. In 2010, the WCSB produced an estimated 2.6 million Bbl/d, consisting of 1.1 million Bbl/d of conventional crude oil and condensate, and 1.5 million Bbl/d of Alberta oil sands crude oil. The production of conventional crude oil has been declining but has been offset by increases in production from the oil sands. The Alberta Energy Resources Conservation Board estimated in its June 2010 report that there are approximately 170 billion barrels of remaining established reserves in the Alberta oil sands.

In June 2010, CAPP forecast WCSB crude oil supply would increase to 3.1 million Bbl/d by 2015 and to 3.7 million Bbl/d by 2020, indicating future growth in Alberta crude oil production. CAPP estimated spending in the oil sands totalled $13 billion in 2010 and forecasts $15 billion of spending in 2011.

Keystone has contracted a significant portion of its capacity. Keystone will compete for spot market throughput with other crude oil pipelines from Alberta and for new long-term contracts as supply from the WCSB increases.

The Williston Basin, located primarily in North Dakota and Montana, is the primary source of crude oil supply for the Bakken Marketlink project. In 2010, the Williston Basin achieved production rates of nearly 400,000 Bbl/d. TransCanada forecasts production levels will reach approximately 550,000 Bbl/d by 2015 due to growth in Bakken shale oil production.

The Permian Basin, located primarily in western Texas, is the primary source of crude oil for the Cushing Marketlink project. Production in the Permian Basin connected to crude oil storage facilities at Cushing is 900,000 Bbl/d and has been growing by approximately three per cent per year since 2006.

The Bakken Marketlink and Cushing Marketlink projects have contracted a significant amount of capacity. Both projects would compete for spot market throughput with other crude oil pipelines in the Williston Basin, Rocky Mountain and U.S. midcontinent regions and for new long-term contracts as supply from connected basins increases.

The markets for crude oil served by TransCanada's Keystone oil pipeline are primarily refiners in the U.S. Midwest, midcontinent and Gulf Coast regions. TransCanada will compete with pipelines that deliver WCSB, Williston Basin and Permian Basin crude oil to these refiners through interconnections with other pipelines. Keystone will also compete with U.S. domestically-produced crude oil and imported crude oil for markets in the U.S. Midwest, Midcontinent and Gulf Coast regions.

Regulatory Risk Regulations and decisions issued by Canadian and U.S. regulatory bodies, particularly the NEB, FERC, EPA and U.S. Department of Transportation, may have a significant impact on the approval, construction, timing and financial performance of TransCanada's crude oil pipelines. TransCanada continuously monitors existing and proposed regulations to determine their possible impact on its Oil Pipelines business.

TransCanada anticipates final U.S. regulatory approvals for the U.S. Gulf Coast Expansion in mid to late 2011. However, if the expansion project as currently proposed is denied regulatory approval, the Company would look to reconfigure all or part of the project and redeploy invested capital to other pipeline opportunities and expense any unmitigated amounts.

Throughput Risk Throughput risk for TransCanada's crude oil pipelines is dependent primarily on crude oil production levels, market competition for crude oil, refinery activity and variations in economic activity. As transportation contracts expire, TransCanada expects its crude oil pipelines to become more exposed to the risk of reduced throughput and revenues to become more likely to experience increased variability. To assist in managing this risk, TransCanada has contracted a significant portion of capacity. Uncontracted capacity is offered to the market on a spot basis, creating the potential for increased earnings.

Plant Availability Optimizing and maintaining plant availability is essential to the success of the oil pipelines business. TransCanada has a proven history of achieving high levels of performance through the use of risk-based comprehensive preventative maintenance programs, prudent operating and capital investment, and a skilled workforce. Further mitigation is provided through firm contracts with Keystone's shippers. In the event of a force majeure, Keystone will continue to receive payments for capacity from its firm contract shippers for a limited time. In the event of a loss of capacity that is not due to force majeure, the firm payments for capacity may be reduced by the extent of the reduced capacity. Unexpected plant outages, including unexpected delays in completing planned outages, could result in lower pipeline throughput, resulting in lower sales revenue, reduced capacity payments and margins, and increased maintenance costs.

Execution and Capital Cost Risk Capital costs related to the construction of Keystone are subject to a capital cost risk- and reward-sharing mechanism with Keystone's long-term committed shippers. This mechanism allows Keystone to adjust its tolls by a factor based on the percentage change in the capital cost of the project. Tolls for Keystone's Wood River/Patoka and Cushing Extension phases will be adjusted by a factor equal to 50 per cent of the percentage change in capital cost. Tolls on the U.S. Gulf Coast Expansion would be adjusted by a factor equal to 75 per cent of the percentage change in capital cost. Capital costs related to the construction of the Bakken Marketlink and Cushing Marketlink projects would not be subject to a capital cost risk- and reward-sharing mechanism with the shippers.

Refer to the Risk Management and Financial Instruments section in this MD&A for information on additional risks and managing risks in the Oil Pipelines business.

OIL PIPELINES – OUTLOOK

North American crude oil demand is expected to remain relatively unchanged in the long term while the availability of foreign sources of supply to North America declines. TransCanada's Oil Pipelines business will continue to focus on contracting and delivering growing crude oil supply to key U.S. markets.

Producers continue to develop new crude oil supply in Western Canada. Several Alberta oil sands projects recently completed or under construction will begin to produce crude oil or will increase crude oil production in 2011 and 2012. Alberta oil sands production is forecast to increase to 2.2 million Bbl/d by 2015 from 1.5 million Bbl/d in 2010 and total Western Canada crude oil supply is projected to grow over the same period to 3.1 million Bbl/d from 2.6 million Bbl/d. The primary market for new crude oil production extends from the U.S. Midwest to the U.S. Gulf Coast and contains a large number of refineries that are capable of handling Canadian light and heavy crude oil blends. Incremental western Canadian crude oil production is expected to replace declining U.S. imports of crude oil from other countries.

The increase in WCSB crude oil exports from Alberta requires access to new markets, including markets in the U.S. Gulf Coast. TransCanada will continue to pursue additional opportunities to transport crude oil from Alberta to U.S. markets.

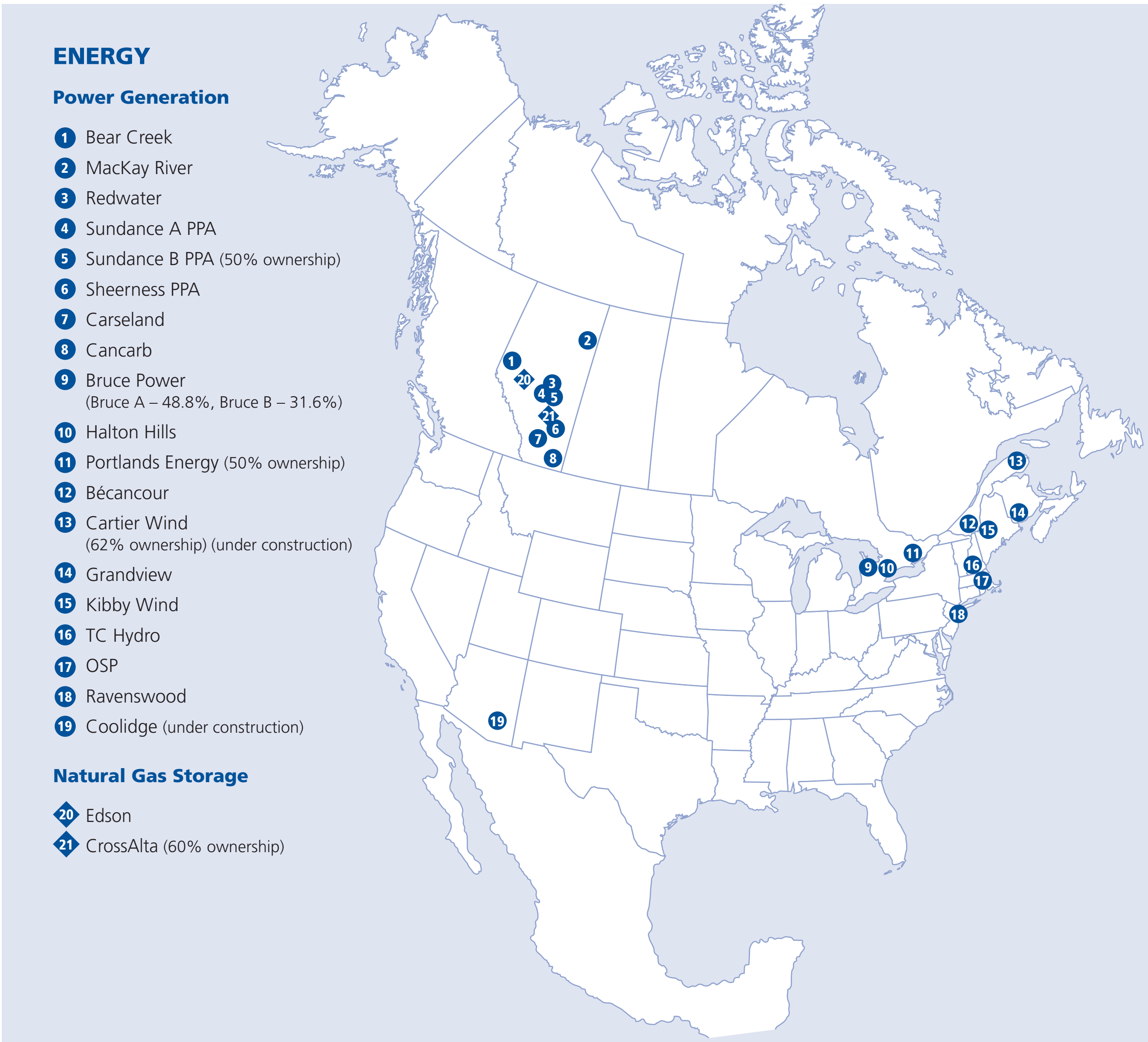
Production in the Williston Basin is also growing and pipeline capacity in the region is constrained. Major markets for Williston Basin crude oil include the U.S. midcontinent and Midwest, with the U.S. Gulf Coast being a potential growth market. There are several competitive proposals to build take-away pipeline capacity for this region and TransCanada will continue to compete for additional opportunities to transport Williston Basin crude oil to U.S. markets.

Take-away capacity is constrained on the pipelines serving the crude oil storage facilities at Cushing. This situation periodically causes the price of West Texas Intermediate crude oil to be depressed relative to world prices. There are several competitive proposals to build take-away pipeline capacity from this region to the U.S. Gulf Coast. TransCanada will continue to compete for additional opportunities to transport Cushing crude oil to U.S. markets.

TransCanada will continue to focus on operational excellence and collaboration with all stakeholders to provide services that will increase the value of the Company's business.

Earnings TransCanada began recording EBITDA from the Wood River/Patoka and the Cushing Extension phases beginning in February 2011 when they commenced full operations. TransCanada expects earnings from its crude oil pipelines to increase through 2011, 2012 and 2013 as Keystone's expansion phases and the proposed Marketlink projects begin delivering crude oil. Based on current long-term commitments for Keystone, TransCanada expects to record annual EBITDA of approximately US$1.3 billion, commencing in 2013, assuming a full year of commercial operations servicing both the U.S. Midwest and Gulf Coast markets. If volumes were to increase to the full commercial design of the system, TransCanada would record annual EBITDA of approximately US$1.5 billion. In the future, Keystone capacity could be economically expanded in response to additional market demand.

Capital Expenditures Total capital spending for Keystone in 2010 was $2.7 billion. Capital spending for Keystone in 2011 is expected to be approximately $1.4 billion.



The following Energy assets are owned 100 per cent by TransCanada unless otherwise stated.

BEAR CREEK An 80 MW natural gas-fired cogeneration plant located near Grande Prairie, Alberta.

MACKAY RIVER A 165 MW natural gas-fired cogeneration plant located near Fort McMurray, Alberta.

REDWATER A 40 MW natural gas-fired cogeneration plant located near Redwater, Alberta.

SUNDANCE A&B TransCanada has the rights to 100 per cent of the generating capacity of the 560 MW Sundance A coal-fired power generating facility under a PPA that expires in 2017. TransCanada also has the rights to 50 per cent of the generating capacity of the 706 MW Sundance B facility under a PPA that expires in 2020. The Sundance facilities are located in south-central Alberta.

SHEERNESS TransCanada has the rights to 756 MW of generating capacity from the Sheerness coal-fired plant under a PPA that expires in 2020. The Sheerness plant is located in southeastern Alberta.

CARSELAND An 80 MW natural gas-fired cogeneration plant located near Carseland, Alberta.

CANCARB A 27 MW facility located in Medicine Hat, Alberta fuelled by waste heat from TransCanada's adjacent facility, which produces thermal carbon black (a natural gas by-product).

BRUCE POWER Bruce Power is a nuclear generating facility located northwest of Toronto, Ontario. TransCanada owns 48.8 per cent of Bruce A, which has four 750 MW reactors. Two of these reactors are currently operating and the remaining two are being refurbished. TransCanada owns 31.6 per cent of Bruce B, which has four operating reactors with a combined capacity of approximately 3,200 MW.

HALTON HILLS A 683 MW natural gas-fired, combined-cycle power plant in Halton Hills, Ontario which began commercial operations in third quarter 2010.

PORTLANDS ENERGY A 550 MW natural gas-fired, combined-cycle power plant located in Toronto, Ontario. The plant is 50 per cent owned by TransCanada.

BÉCANCOUR A 550 MW natural gas-fired cogeneration power plant located near Trois-Rivières, Québec.

CARTIER WIND The 590 MW Cartier Wind farm consists of five wind power projects located in Québec and is 62 per cent owned by TransCanada. Three of the wind farms, Baie-des-Sables, Anse-à-Valleau and Carleton, are operating and have a total generating capacity of 320 MW. The two remaining wind farms, Gros-Morne and Montagne-Sèche, are under construction and will have total generating capacity of 270 MW.

GRANDVIEW A 90 MW natural gas-fired cogeneration power plant located in Saint John, New Brunswick.

KIBBY WIND A 132 MW wind farm located in Kibby and Skinner Townships in Maine. The 66 MW second phase of Kibby Wind was placed in service in October 2010.

TC HYDRO TC Hydro has a total generating capacity of 583 MW and comprises 13 hydroelectric facilities, including stations and associated dams and reservoirs, on the Connecticut and Deerfield rivers in New Hampshire, Vermont and Massachusetts.

OSP A 560 MW natural gas-fired, combined-cycle facility located in Burrillville, Rhode Island.

RAVENSWOOD A 2,480 MW multiple-unit generating facility located in Queens, New York, employing dual fuel-capable steam turbine, combined-cycle and combustion turbine technology.

COOLIDGE A 575 MW simple-cycle, natural gas-fired peaking power facility under construction in Coolidge, Arizona.

EDSON An underground natural gas storage facility connected to the Alberta System near Edson, Alberta. Edson's central processing system is capable of maximum injection and withdrawal rates of 725 mmcf/d of natural gas, and has a working storage capacity of approximately 50 Bcf.

CROSSALTA A 68 Bcf underground natural gas storage facility connected to the Alberta System near Crossfield, Alberta. CrossAlta's central processing system is capable of maximum injection and withdrawal rates of 550 mmcf/d of natural gas. TransCanada owns 60 per cent of CrossAlta.

ENERGY – HIGHLIGHTS

- Energy's comparable EBIT was $748 million in 2010, a decrease of $36 million from $784 million in 2009.
- In 2010, the Company invested $1.1 billion in Energy capital projects, including:
    - the 683 MW Halton Hills generating facility, which was fully commissioned in September 2010, on time and on budget;
    - the second phase of the Kibby Wind farm, which was placed in service in October 2010 and included the installation of an additional 22 turbines, ahead of schedule and on budget; and
    - the restart of Bruce A Units 1 and 2 as well as construction of Coolidge and the two remaining wind farms at Cartier Wind.
- Successful installation of the last of the fuel channel assemblies (FCA) and significant staff demobilization at Bruce A Unit 2 was achieved.
- Approximately 1,500 MW of generation capacity was under construction and in development at December 31, 2010, at an anticipated total capital cost of approximately $3.2 billion.

POWER PLANTS – NOMINAL GENERATING CAPACITY AND FUEL TYPE

	MW	Fuel Type
Canadian Power		
Western Power		
Sheerness	756	Coal
Coolidge[1]	575	Natural gas
Sundance A	560	Coal
Sundance B[2]	353	Coal
MacKay River	165	Natural gas
Carseland	80	Natural gas
Bear Creek	80	Natural gas
Redwater	40	Natural gas
Cancarb	27	Natural gas
	2,636	
Eastern Power		
Halton Hills	683	Natural gas
Bécancour	550	Natural gas
Cartier Wind[3]	365	Wind
Portlands Energy[4]	275	Natural gas
Grandview	90	Natural gas
	1,963	
Bruce[5]	2,480	Nuclear
	7,079	
U.S. Power		
Ravenswood	2,480	Natural gas/oil
TC Hydro	583	Hydro
OSP	560	Natural gas
Kibby Wind	132	Wind
	3,755	
Total Nominal Generating Capacity	10,834	

(1) Currently under construction.

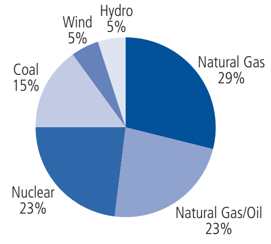
(2) Represents TransCanada's 50 per cent share of the Sundance B power plant output.

(3) Represents TransCanada's 62 per cent share of the total 590 MW project, including 168 MW under construction.

(4) Represents TransCanada's 50 per cent share of the total 550 MW facility.

(5) Represents TransCanada's 48.8 per cent proportionate interest in Bruce A and 31.6 per cent proportionate interest in Bruce B.

Power by Fuel Source



ENERGY – RESULTS

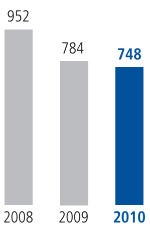
Year ended December 31 *(millions of dollars)*	**2010**	2009	2008
Canadian Power			
Western Power	**220**	279	510
Eastern Power[1]	**231**	220	147
Bruce Power	**298**	352	275
General, administrative and support costs	**(38)**	(39)	(39)
Canadian Power Comparable EBITDA[2]	**711**	812	893
Depreciation and amortization	**(242)**	(227)	(198)
Canadian Power Comparable EBIT[2]	**469**	585	695
U.S. Power (in U.S. dollars)			
Northeast Power[3]	**335**	210	256
General, administrative and support costs	**(32)**	(40)	(38)
U.S. Power Comparable EBITDA[2]	**303**	170	218
Depreciation and amortization	**(116)**	(92)	(38)
U.S. Power Comparable EBIT[2]	**187**	78	180
Foreign exchange	**7**	8	8
U.S. Power Comparable EBIT[2] (in Canadian dollars)	**194**	86	188
Natural Gas Storage			
Alberta Storage	**140**	173	152
General, administrative and support costs	**(8)**	(9)	(14)
Natural Gas Storage Comparable EBITDA[2]	**132**	164	138
Depreciation and amortization	**(15)**	(14)	(17)
Natural Gas Storage Comparable EBIT[2]	**117**	150	121
Business Development Comparable EBITDA and EBIT[2]	**(32)**	(37)	(52)
Energy Comparable EBIT[2]	**748**	784	952
Summary:			
Energy Comparable EBITDA[2]	**1,125**	1,131	1,210
Depreciation and amortization	**(377)**	(347)	(258)
Energy Comparable EBIT[2]	**748**	784	952
Specific items:			
Risk management activities	**(8)**	1	–
Write-down of Broadwater LNG project costs	**–**	–	(41)
Energy EBIT[2]	**740**	785	911

(1) Includes Halton Hills, Portlands Energy and Carleton effective September 2010, April 2009 and November 2008, respectively.

(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 and two of Kibby Wind, and Ravenswood effective October 2009, October 2010 and August 2008, respectively.

Energy Comparable EBIT
(millions of dollars)



Energy's Comparable EBIT was $748 million in 2010 compared to $784 million in 2009 and $952 million in 2008. Comparable EBIT in 2010 and 2009 excluded net unrealized losses of $8 million and net unrealized gains of $1 million, respectively, from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. TransCanada manages its proprietary Natural Gas Storage business 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. Fair value adjustments are recorded each period on proprietary natural gas inventory in storage and on the forward contracts, however, these adjustments are not representative of the amounts that will be realized on settlement. U.S. Power focuses on selling power under short- and long-term contracts to wholesale, commercial and industrial customers and manages exposure to fluctuations in spot prices on these power sales either with the purchase of power or the purchase of fuel to generate power from its assets, effectively locking in positive margins. These Natural Gas Storage and U.S. Power contracts provide effective economic hedges which effectively lock in a margin but do not meet the specific criteria required for hedge accounting treatment and, therefore, are recorded at their fair value based on forward market prices for the contracted month of delivery. These forwards are excluded in determining Comparable Earnings as their fair value is not representative of amounts that will be realized on settlement. Comparable EBIT in 2008 excluded the $41 million write-down of costs previously capitalized for the Broadwater LNG project.

ENERGY – FINANCIAL ANALYSIS

Western Power As at December 31, 2010, Western Power owned or had the rights to approximately 2,600 MW of power supply in Alberta and the western U.S. from its three long-term power purchase arrangements (PPA), five natural gas-fired cogeneration facilities and a simple-cycle, natural gas peaking facility under construction in Arizona. The current operating power supply portfolio of Western Power in Alberta comprises approximately 1,700 MW of low-cost, baseload, coal-fired generation through the three long-term PPAs and approximately 400 MW of natural gas-fired cogeneration assets. This supply portfolio includes some of the lowest cost and most competitive power generation in the Alberta market area. The Sheerness and Sundance B PPAs expire in 2020, while the Sundance A PPA expires in 2017. Plant operations in Alberta consist of five natural gas-fired cogeneration power plants whose capacity ranges from 27 MW to 165 MW. A portion of the expected output from the Western Power facilities is sold under long-term contracts and the remaining output is subject to fluctuations in the price of power and natural gas.

Western Power relies on its two integrated functions, marketing and plant operations, to generate earnings. The marketing function, based in Calgary, Alberta, purchases and resells electricity sourced through the PPAs, markets uncommitted volumes from the cogeneration facilities, and purchases and resells power and natural gas to maximize the value of the cogeneration facilities. The marketing function is critical for optimizing Energy's return from its portfolio of power supply and managing risks associated with uncontracted volumes. A portion of Energy's power is sold into the spot market to ensure supply in case of unexpected plant outages. 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 TransCanada would otherwise have to purchase electricity in the open market to fulfil its contractual sales obligations. To reduce exposure to spot market prices on uncontracted volumes, Western Power had, as at December 31, 2010, fixed-price power sales contracts to sell approximately 7,400 gigawatt hours (GWh) in 2011 and 6,300 GWh in 2012.

Eastern Power Eastern Power owns approximately 2,000 MW of power generation capacity, including facilities under construction. Eastern Power's current operating power generation assets are Halton Hills, Bécancour, three Cartier Wind farms, Portlands Energy and Grandview.

Halton Hills was placed in service in September 2010 and provides power under a 20-year Clean Energy Supply contract with the Ontario Power Authority (OPA).

Bécancour's entire power output is supplied to Hydro-Québec under a 20-year power purchase contract expiring in 2026. Steam from this facility is sold to an industrial customer for use in commercial processes. Electricity generation at the Bécancour power plant has been suspended since January 2008 as a result of an agreement entered into with Hydro-Québec. Under the agreement, TransCanada continues to receive payments similar to those that would have been received under the normal course of operation. Suspension of electricity generation at the Bécancour power facility is discussed further in the Energy – Opportunities and Developments section in this MD&A.

Three of Cartier Wind's operating wind farms, Carleton, Anse-à-Valleau, and Baie-des-Sables, were placed in service in November 2008, 2007 and 2006, respectively. Output from these wind farms is supplied to Hydro-Québec under 20-year power purchase contracts.

Portlands Energy was placed in service in April 2009. This facility provides power under a 20-year Accelerated Clean Energy Supply contract with the OPA.

Grandview is located on the site of the Irving Oil refinery in Saint John, New Brunswick. TransCanada and Irving Oil are under a 20-year tolling arrangement, which expires in 2025, through which Irving Oil supplies fuel for the 90 MW plant and is contracted to purchase 100 per cent of the plant's heat and electricity output.

Eastern Power is focused on selling power under long-term contracts. In 2008, 2009 and 2010, all of Eastern Power sales volumes were sold under contract and are expected to continue to be 100 per cent sold under contract in 2011 and 2012.

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

Year ended December 31 *(millions of dollars)*	**2010**	2009	2008
Revenues			
Western power	**714**	788	1,140
Eastern power[2]	**330**	281	175
Other[3]	**84**	86	138
	1,128	1,155	1,453
Commodity purchases resold			
Western power	**(431)**	(451)	(517)
Other[3][4]	**(26)**	(26)	(64)
	(457)	(477)	(581)
Plant operating costs and other	**(220)**	(179)	(215)
General, administrative and support costs	**(38)**	(39)	(39)
Comparable EBITDA[1]	**413**	460	618
Depreciation and amortization	**(140)**	(138)	(124)
Comparable EBIT[1]	**273**	322	494

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

(2) Includes Halton Hills, Portlands Energy and Carleton effective September 2010, April 2009 and November 2008, respectively.

(3) Includes sales of excess natural gas purchased for generation, sales of thermal carbon black and sales of sulphur in 2008. 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 and 2008 reflect amounts reclassified to Other Revenues from Other Commodity Purchases Resold.

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

Western and Eastern Canadian Power Operating Statistics[1]

Year ended December 31	2010	2009	2008
Sales Volumes (GWh)			
Supply			
Generation			
Western Power	**2,373**	2,334	2,322
Eastern Power	**2,359**	1,550	1,069
Purchased			
Sundance A & B and Sheerness PPAs	**10,785**	10,603	12,368
Other purchases	**429**	529	970
	15,946	15,016	16,729
Sales			
Contracted			
Western Power	**10,211**	9,944	11,284
Eastern Power	**2,375**	1,588	1,232
Spot			
Western Power	**3,360**	3,484	4,213
	15,946	15,016	16,729
Plant Availability[2]			
Western Power[3]	**95%**	93%	87%
Eastern Power[4]	**94%**	97%	97%

(1) Includes Halton Hills, Portlands Energy and Carleton effective September 2010, April 2009 and November 2008, respectively.

(2) Plant availability represents the percentage of time in a year that the plant is available to generate power regardless of whether it is running.

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

(4) Bécancour has been excluded from the availability calculation, as power generation at the facility has been suspended since 2008.

Western Power's Comparable EBITDA of $220 million and Power Revenues of $714 million in 2010 decreased $59 million and $74 million, respectively, compared to 2009 primarily due to lower overall realized power prices. Realized prices were negatively affected by lower contracted prices in 2010 compared to 2009 due to the continued impact of the North American economic downturn and the timing of certain unplanned outages that occurred in 2010 during periods of high spot prices. Approximately 25 per cent of Western Power's sales volumes were sold in the spot market in 2010 compared to 26 per cent in 2009.

Eastern Power's Comparable EBITDA of $231 million and Power Revenues of $330 million in 2010 increased $11 million and $49 million, respectively, compared to 2009. These increases were primarily due to incremental earnings from Halton Hills and Portlands Energy, which went into service September 2010 and April 2009, respectively, partially offset by lower contracted revenue from the Bécancour facility. Results from Bécancour are consistent with the expected contracted earnings based on the original electricity supply contract with Hydro-Québec.

Plant Operating Costs and Other, which includes natural gas fuel consumed in power generation, of $220 million in 2010 increased $41 million from 2009 primarily due to incremental fuel consumed at Portlands Energy and Halton Hills.

Western Power's Comparable EBITDA of $279 million and Power Revenues of $788 million in 2009 decreased $231 million and $352 million, respectively, compared to 2008. The decrease was primarily due to lower overall realized prices on reduced volumes of power sold as a result of the economic downturn. Western Power's Comparable EBITDA in 2008 included $23 million related to sulphur sales. Commodity Purchases Resold decreased $66 million in 2009 compared to 2008 primarily due to a reduction in volumes purchased and the expiry of certain retail contracts. Approximately 26 per cent of power sales volumes were sold in the spot market in 2009 compared to 27 per cent in 2008.

Eastern Power's Comparable EBITDA of $220 million and Power Revenues of $281 million in 2009 increased $73 million and $106 million, respectively, compared to 2008. The increase was primarily due to incremental earnings from Portlands Energy, which was placed in service in April 2009, and the Carleton wind farm at Cartier Wind, which went into service in November 2008, as well as higher contracted revenue from the Bécancour facility.

Other Revenues and Other Commodity Purchases Resold were $86 million and $26 million, respectively, in 2009 compared to $138 million and $64 million, respectively, in 2008. The decreases in 2009 reflect the lower price of natural gas purchased for operations but not used. Other Revenues in 2008 included $23 million related to sulphur sales.

Plant Operating Costs and Other, which includes natural gas fuel consumed in power generation, of $179 million in 2009 decreased $36 million from 2008 primarily due to lower prices for natural gas in Western Power, partially offset by incremental fuel consumed at Portlands Energy.

Western Power's plants operated with an average availability of approximately 95 per cent in 2010, 93 per cent in 2009 and 87 per cent in 2008. The increases in 2010 and 2009 were primarily due to the return to service of the Cancarb facility in April 2009.

Bruce Power Bruce Power is a nuclear power generation facility located northwest of Toronto, Ontario and comprises Bruce A and Bruce B. Bruce A has four 750 MW reactors, two of which are operating and two are being refurbished. The two units being refurbished are expected to resume commercial operations in first quarter and third quarter 2012. Bruce B has four operating reactors with a combined capacity of 3,200 MW. As at December 31, 2010, TransCanada and BPC Generation Infrastructure Trust (BPC), a trust established by the Ontario Municipal Employees Retirement System (OMERS), each owned a 48.8 per cent interest in Bruce A (2009 – 48.8 per cent; 2008 – 48.9 per cent). The remaining 2.4 per cent interest in Bruce A is owned by the Power Workers' Union Trust (PWU), the Society of Energy Professionals Trust (SEP) and the Bruce Power Employee Investment Trust. Bruce A subleases Bruce A Units 1 to 4 from Bruce B. TransCanada, OMERS and Cameco Corporation each own 31.6 per cent of Bruce B, which consists of Units 5 to 8 and the supporting site infrastructure. The remaining interest in Bruce B is owned by PWU and SEP.

The following Bruce Power financial results reflect TransCanada's proportionate share of the eight Bruce Power units, six of which were operating:

Bruce Power Results(1)
(TransCanada's proportionate share)

Year ended December 31 *(millions of dollars unless otherwise indicated)*	2010	2009	2008
Revenues(2)	862	883	785
Operating expenses	(564)	(531)	(510)
Comparable EBITDA(1)	298	352	275
Bruce A Comparable EBITDA(1)	91	48	78
Bruce B Comparable EBITDA(1)	207	304	197
Comparable EBITDA(1)	298	352	275
Depreciation and amortization	(102)	(89)	(74)
Comparable EBIT(1)	196	263	201
Bruce Power – Other Information			
Plant availability(3)			
Bruce A	81%	78%	82%
Bruce B	91%	91%	87%
Combined Bruce Power	88%	87%	86%
Planned outage days			
Bruce A	60	56	91
Bruce B	70	45	100
Unplanned outage days			
Bruce A	64	82	27
Bruce B	34	47	65
Sales volumes (GWh)			
Bruce A	5,026	4,894	5,159
Bruce B	8,184	7,767	7,799
	13,210	12,661	12,958
Results per MWh			
Bruce A power revenues	$65	$64	$62
Bruce B power revenues(4)	$58	$64	$57
Combined Bruce Power revenues	$60	$64	$59
Percentage of Bruce B output sold to spot market(5)	82%	43%	33%

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

(2) Revenues include Bruce A fuel cost recoveries of $29 million in 2010 (2009 – $34 million; 2008 – $30 million). Revenues also include Bruce B unrealized losses of $6 million as a result of changes in the fair value of held-for-trading derivatives in 2010 (2009 – $5 million gains; 2008 – $2 million losses).

(3) Plant availability represents the percentage of time in a year that the plant is available to generate power regardless of whether it is running.

(4) Includes revenues received under the floor price mechanism, from contract settlements and deemed generation, and the associated volumes.

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

TransCanada's proportionate share of Bruce Power's Comparable EBITDA decreased $54 million to $298 million in 2010 compared to 2009. Comparable EBITDA in 2010 included the positive net impact of a payment made in 2010 by Bruce B to Bruce A related to amendments made in 2009 to the agreements with the OPA. The net positive impact to TransCanada from the payment reflected TransCanada's higher percentage ownership in Bruce A.

TransCanada's proportionate share of Bruce A's Comparable EBITDA increased $43 million to $91 million in 2010 compared to 2009 primarily as a result of the payment received from Bruce B, lower operating expenses due to a decrease in outage days and higher volumes.

TransCanada's proportionate share of Bruce B's Comparable EBITDA decreased $97 million to $207 million in 2010 compared to 2009. The decrease was primarily due to lower realized prices resulting from expiration of fixed-price contracts at higher prices, the payment made to Bruce A and a higher annual lease expense in 2010, partially offset by higher volumes. Provisions in the lease agreement with Ontario Power Generation allow for a reduction in the annual lease expense if the annual average Ontario spot price for electricity is less than $30 per megawatt hour (MWh). No lease expense reduction was available in 2010 while lease expense was reduced in 2009. The annual average Ontario spot price was $36.25 per MWh in 2010 compared to $29.52 per MWh in 2009 and $48.83 per MWh in 2008.

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. In both 2010 and 2009, no amounts recorded in revenue were repaid. Bruce B did not recognize into revenue any of the support payments received under the floor price mechanism in 2008 as the average spot price exceeded the floor price.

Bruce Power's Depreciation and Amortization increased $13 million in 2010 compared to 2009 and $15 million in 2009 compared to 2008 primarily due to capital additions.

TransCanada's proportionate share of Bruce Power's Comparable EBITDA of $352 million in 2009 increased $77 million compared to 2008 as a result of higher realized prices and reduced annual lease expense, partially offset by lower volumes and higher operating expenses for Bruce A.

TransCanada's proportionate share of Bruce Power's generation in 2010 increased to 13,210 GWh compared to 12,661 GWh in 2009, partially due to periods in 2009 when the Independent Electricity System Operator (IESO) curtailed certain units at Bruce Power to address surplus baseload generation in Ontario. During these unit curtailments by the IESO, Bruce Power received deemed generation payments at OPA contract prices. Including deemed generation, the combined average availability of Bruce A and Bruce B was 88 per cent in 2010 compared to 87 per cent in 2009 and 86 per cent in 2008.

The overall plant availability percentage in 2011 is expected to be in the mid-80s for the two operating Bruce A units and in the high 80s for the four Bruce B units. Bruce A expects an outage of approximately one week on Unit 3 in July 2011 and, following approval from the Canadian Nuclear Safety Commission, the West Shift Plus outage of approximately six months is scheduled to commence in early November 2011 on Unit 3. The West Shift Plus outage is a key part of the life extension strategy for Unit 3 and is an extension of the West Shift program which was successfully executed in 2009. A maintenance outage of approximately three weeks commenced on February 1, 2011 on Bruce B Unit 8 and outages of approximately seven weeks are scheduled to begin in mid-April 2011 for Bruce B Unit 7 and in mid-October 2011 for Bruce B Unit 5.

Bruce A

Under a contract with the OPA, all of the output from Bruce A is sold at a fixed price per MWh, adjusted annually for inflation on April 1. In addition, fuel costs are recovered from the OPA.

Bruce A Fixed Price

	per MWh
April 1, 2010 – March 31, 2011	$64.71
April 1, 2009 – March 31, 2010	$64.45
April 1, 2008 – March 31, 2009	$63.00

Bruce B

As part of Bruce Power's contract with the OPA, all output from Bruce B Units 5 to 8 is subject to a floor price adjusted annually for inflation on April 1.

Bruce B Floor Price

	per MWh
April 1, 2010 – March 31, 2011	$48.96
April 1, 2009 – March 31, 2010	$48.76
April 1, 2008 – March 31, 2009	$47.66

Payments received pursuant to the Bruce B floor price mechanism were previously subject to a recapture payment dependent on annual spot prices over the entire term of the contract. In July 2009, the contract with the OPA was amended making payments received pursuant to the floor price mechanism subject to recapture payments dependent on monthly average spot prices only within each calendar year.

Bruce B enters into fixed-price contracts under which it receives the difference between the contract price and spot price. As a result, Bruce B's 2010 realized price of $58 per MWh reflected revenues recognized from both the floor price mechanism and contract sales. Realized prices were $64 per MWh and $57 per MWh in 2009 and 2008, respectively. Most of the higher-priced contracts entered into in prior years expired at December 31, 2010, which is expected to result in a further reduction in realized prices at Bruce B for future periods. As at December 31, 2010, Bruce B had entered into fixed-price contracts to sell forward approximately 500 GWh for 2011 and 700 GWh for 2012, representing TransCanada's proportionate share.

U.S. Power U.S. Power owns approximately 3,800 MW of power generation capacity, consisting of Ravenswood, TC Hydro, Ocean State Power (OSP), and Kibby Wind. Ravenswood, located in Queens, New York and acquired in August 2008, is a 2,480 MW natural gas and oil-fired generating facility consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology with the capacity to serve approximately 20 per cent of the overall peak load in New York City. The TC Hydro assets include 13 hydroelectric stations housing a total of 39 hydroelectric generating units in New Hampshire, Vermont and Massachusetts with total generating capacity of 583 MW. OSP, a 560 MW natural gas-fired combined-cycle facility, is the largest power plant in Rhode Island and Kibby Wind is a 132 MW wind farm located in Maine. The first 66 MW phase of Kibby Wind was placed in service in October 2009 and the second 66 MW phase went into service in October 2010.

U.S. Power conducts its business primarily in the deregulated New England, New York and PJM Interconnection power markets, and continues to expand its marketing presence and customer base. PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. U.S. Power focuses on selling power under short- and long-term contracts to wholesale, commercial and industrial customers in these markets. To manage exposure to fluctuations in spot prices, power sales are hedged with the purchase of power or the purchase of fuel to generate power from its assets, effectively locking in positive margins.

The New York Independent System Operator (NYISO) relies on a locational capacity market intended to promote investment in new and existing power resources needed to meet growing consumer demand and maintain a reliable power system. At present, a series of voluntary forward auctions and a mandatory spot demand curve price setting process are used to determine the price paid to capacity suppliers. There are two annual six-month strip forward auctions and 12 monthly forward auctions in which buyer and seller participation is optional. All remaining available capacity is required to participate in a monthly spot auction in the final week prior to each capacity month. The spot auction clears at a price based on a downward-sloping demand curve, the parameters of which are determined by the NYISO and approved by the FERC. There are separate demand curves for each of three defined capacity zones: Long Island, New York City and Rest of State. The Ravenswood capacity is located in the New York City capacity zone.

The New England Power Pool relies on a Forward Capacity Market (FCM) to promote investment in new and existing power resources needed to meet growing consumer demand and maintain a reliable power system. This capacity market operated on a transition basis from 2007 to 2009. During this period, OSP and TC Hydro received capacity transition payments under this mechanism as specified in the FERC-approved FCM settlement. Beginning in June 2010, the price paid for capacity was determined by annual competitive FCM auctions, which are held three years in advance of the applicable capacity year. Future auction results will be affected by actual versus projected demand, the pace of progress in developing new qualifying resources that bid into the auctions and other factors.

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

Year ended December 31 *(millions of U.S. dollars)*	**2010**	2009	2008
Revenues			
Power(3)	**1,090**	742	1,143
Capacity	**231**	169	80
Other(3)(4)	**78**	79	42
	1,399	990	1,265
Commodity purchases resold(3)			
Power	**(543)**	(309)	(510)
Other(5)	**–**	–	(257)
	(543)	(309)	(767)
Plant operating costs and other(4)	**(521)**	(471)	(242)
General, administrative and support costs	**(32)**	(40)	(38)
Comparable EBITDA(1)	**303**	170	218
Depreciation and amortization	**(116)**	(92)	(38)
Comparable EBIT(1)	**187**	78	180

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

(2) Includes phases one and two of Kibby Wind, and Ravenswood as of October 2009, October 2010 and August 2008, respectively.

(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 and 2008 reflect amounts reclassified to Power Revenues from Commodity Purchases Resold and Other Revenues.

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

(5) Includes the cost of excess physical natural gas not used in operations, which was purchased under the terms of contracts that expired in 2008.

U.S. Power Operating Statistics[1]

Year ended December 31	**2010**	2009	2008
Sales Volumes (GWh)			
Supply			
Generation	**6,755**	5,993	3,974
Purchased	**8,899**	5,310	6,020
	15,654	11,303	9,994
Sales			
Contracted	**14,485**	10,205	9,758
Spot	**1,169**	1,098	236
	15,654	11,303	9,994
Plant Availability[2]	**86%**	79%	75%

(1) Includes phases one and two of Kibby Wind, and Ravenswood as of October 2009, October 2010 and August 2008, respectively.

(2) Plant availability represents the percentage of time in a year that the plant is available to generate power regardless of whether it is running.

U.S. Power's Comparable EBITDA was US$303 million in 2010, US$133 million higher than the US$170 million earned in 2009. The increase was primarily due to growth in capacity revenue, higher volumes of power sold in the New England and New York markets, reduced lease costs, higher realized prices and incremental earnings from Kibby Wind.

U.S. Power's Power Revenues of US$1,090 million in 2010 increased US$348 million from US$742 million in 2009 primarily due to higher volumes of power sold, higher realized power prices, and incremental revenues from Kibby Wind. Capacity Revenue of US$231 million in 2010 increased US$62 million from US$169 million in 2009 primarily due to higher capacity prices as a result of the long-planned retirement of a power generating facility owned by the New York Power Authority, which occurred at the end of January 2010. The increases in capacity prices were partially offset by the impact of the Ravenswood Unit 30 outage, which occurred from September 2008 to May 2009.

Power Commodity Purchases Resold increased US$234 million in 2010 compared to 2009 primarily due to an increase in the quantity of power purchased for resale under U.S. Power's power sales commitments to wholesale, commercial and industrial customers in New England.

Plant Operating Costs and Other increased US$50 million in 2010 compared to 2009 primarily due to higher generation volumes and fuel costs, partially offset by reduced lease costs.

Depreciation and Amortization increased US$24 million in 2010 compared to 2009 and includes a full year of depreciation expense for phase one of Kibby Wind.

U.S. Power's Comparable EBITDA was US$170 million in 2009, US$48 million lower than the US$218 million earned in 2008. The decrease was primarily due to reduced power prices and lower margins realized on generation volumes in New England, partially offset by the benefit of forward hedging activities. Lower realized prices were a result of the economic downturn coupled with unseasonably mild weather. These decreases were partially offset by incremental revenue realized on contract sales at higher than average spot market prices in New England and by incremental EBITDA from a full year of operations at the Ravenswood facility, which was acquired in August 2008. On December 31, 2008, Ravenswood fulfilled its obligations under a tolling agreement with a third party that was in place at the time of its acquisition.

U.S. Power achieved plant availability of 86 per cent in 2010 compared to 79 per cent in 2009 and 75 per cent in 2008. The fluctuations in availability were primarily due to the unplanned outage of the Ravenswood Unit 30 from September 2008 to May 2009.

In 2010, seven per cent of power sales volumes were sold into the spot market compared to 10 per cent in 2009. As at December 31, 2010, U.S. Power had entered into fixed-price power sales contracts to sell approximately 11,400 GWh in 2011 and 6,600 GWh in 2012, including financial contracts. Certain contracted volumes are dependent on customer usage levels and actual amounts contracted in future periods will depend on market liquidity and other factors.

Natural Gas Storage TransCanada owns or has rights to 129 Bcf of non-regulated natural gas storage capacity in Alberta, including a 60 per cent ownership interest in CrossAlta, an independently operated storage facility, and contracts for long-term Alberta-based storage capacity from a third party, which expire in 2030, subject to early termination rights in 2015.

Natural Gas Storage Capacity

	Working Gas Storage Capacity (Bcf)	Maximum Injection/ Withdrawal Capacity (mmcf/d)
Edson	50	725
CrossAlta(1)	41	550
Third-party storage	38	630
	129	1,905

(1) Represents TransCanada's 60 per cent ownership interest in CrossAlta. Working gas storage capacity can vary due to the amount of base gas in the facility.

The Company's natural gas storage capability helps balance seasonal and short-term supply and demand, and adds flexibility to the delivery of natural gas to markets in Alberta and the rest of North America. Alberta-based storage will continue to serve market needs and could play an important role as additional natural gas supplies are connected to North American markets. Energy's natural gas storage business operates independently from TransCanada's regulated natural gas transmission business and from ANR's regulated storage business, which is included in the Natural Gas Pipelines segment.

TransCanada manages the exposure of its non-regulated natural gas storage assets to seasonal natural gas price spreads by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales.

Market volatility creates arbitrage opportunities and TransCanada's storage facilities provide customers with the ability to capture value from short-term price movements. At December 31, 2010, TransCanada had contracted approximately 56 per cent of the total 129 Bcf of working gas storage capacity in 2011 and 27 per cent of storage capacity in 2012. Earnings from third-party storage capacity contracts are recognized over the terms of the contracts.

Proprietary natural gas storage transactions consist of a forward purchase of natural gas to be injected into storage and a simultaneous forward sale of natural gas for withdrawal at a later period, typically during the winter withdrawal season. By matching purchase and sales volumes on a back-to-back basis, TransCanada locks in future positive margins, effectively eliminating its exposure to natural gas seasonal price spreads. The seasonal nature of natural gas storage generally results in higher revenue in the winter months.

Natural Gas Storage's Comparable EBITDA in 2010 was $132 million compared to $164 million in 2009. The $32 million decrease in EBITDA was primarily due to decreased proprietary natural gas and third-party storage revenues as a result of lower realized natural gas price spreads. Natural Gas Storage's Comparable EBITDA was $164 million in

2009 compared to $138 million in 2008. The increase in 2009 was due to increased storage revenues as a result of higher realized natural gas price spreads.

Business Development Business Development Comparable EBITDA losses decreased $5 million in 2010 compared to 2009 and $15 million in 2009 compared to 2008 primarily due to the timing of expenses on certain key projects.

ENERGY – OPPORTUNITIES AND DEVELOPMENTS

Bruce Power In accordance with terms of the 2005 Bruce Power Refurbishment Implementation Agreement (BPRIA) between Bruce Power and the OPA, Bruce A committed to refurbish and restart the idle Units 1 and 2 and refurbish the operating Units 3 and 4 under certain conditions.

In August 2007, Bruce Power and the OPA agreed to amend the BPRIA to expand the scope of the refurbishment contemplated for Unit 4.

In July 2009, Bruce Power and the OPA agreed to amend the BPRIA to include the following:

- elimination of the requirement that annual net payments received under the Bruce B floor price mechanism be subject to repayment in future years. Instead, amounts received under the floor price mechanism within a calendar year will be subject to repayment only if the monthly average spot price for that year exceeds the floor price;
- Bruce Power will receive deemed generation payments from the OPA at contract prices in the event Bruce Power's generation is reduced due to system curtailments on the IESO-controlled grid in Ontario;
- the original terms of the BPRIA provided that the cumulative contingent support payments received by Bruce A, which are equal to the difference between the fixed prices under the BPRIA and spot market prices, were capped at $575 million until both of Units 1 and 2 go into commercial service. The amendment removed the $575 million cap on these contingent support payments and stipulated that the payments would be suspended if both Units 1 and 2 were not in commercial service by December 31, 2011; and
- the capital cost-sharing mechanism for the refurbishment and restart of Bruce A Units 1 and 2 was amended to eliminate the requirement that the OPA share in any costs for Units 1 and 2 in excess of $3.4 billion. Previously, the OPA was responsible for 25 per cent of cost refurbishment above $3.4 billion through a future adjustment to the fixed price paid to Bruce Power for power generated by the Bruce A units.

In February 2011, the BPRIA was further amended to reflect the following:

- the suspension date for contingent support payments on Bruce A output was extended to June 1, 2012 from December 31, 2011 and, as a result, all output from Bruce A will receive spot prices from June 1, 2012 until the restart of Units 1 and 2 is complete; and
- a recovery of costs incurred by Bruce A in connection with development of fuel programs.

Refurbishment work on Units 1 and 2 reached a significant milestone in December 2010 with Atomic Energy of Canada Ltd.'s (AECL) substantial completion of work in connection with Unit 2. Substantial completion of the Unit 2 work resulted in a significant reduction of the AECL workforce and enabled AECL to focus on the installation of FCAs at Unit 1. The installation of these FCAs is the final stage of AECL's work on the reactors. AECL is expected to complete FCA installation on Unit 1 in second quarter 2011.

Subject to regulatory approval, Bruce Power expects to load fuel into Unit 2 in second quarter 2011 and achieve a first synchronization of the generator to the electrical grid by the end of 2011, with commercial operation expected to occur in first quarter 2012. Bruce Power expects to load fuel into Unit 1 in third quarter 2011, with a first synchronization of the generator during first quarter 2012 and commercial operation expected to occur during third quarter 2012. Plant commissioning and testing are underway and will accelerate in second quarter 2011 when construction activities are essentially complete. TransCanada's share of the total capital cost is expected to be approximately $2.4 billion.

As at December 31, 2010, Bruce A had incurred approximately $4.0 billion in costs for the refurbishment and restart of Units 1 and 2, and approximately $0.3 billion for the refurbishment of Units 3 and 4.

Halton Hills The $700 million Halton Hills generating station went into service on September 1, 2010, on time and on budget. Power from the 683 MW natural gas-fired power plant in Halton Hills, Ontario is sold to the OPA under a 20-year Clean Energy Supply contract.

Oakville In September 2009, the OPA awarded TransCanada a 20-year Clean Energy Supply contract to build, own and operate a 900 MW power generating station in Oakville, Ontario. TransCanada expected to invest approximately $1.2 billion in the natural gas-fired, combined-cycle plant. In October 2010, the Government of Ontario announced that it would not proceed with the Oakville generating station. TransCanada is negotiating a settlement with the OPA that would terminate the Clean Energy Supply contract and compensate TransCanada for the economic consequences associated with the contract's termination.

Kibby Wind The 66 MW second phase of the Kibby Wind power project went into service in October 2010 and included the installation of an additional 22 turbines, which were all erected ahead of schedule and on budget. The two phases of the project have a combined capacity of 132 MW and total capital cost of US$350 million. A total of 30 MW of energy and associated renewable energy credits produced by Kibby Wind have been sold at fixed prices for a term of 10 years. Phase one of the project received government incentive payments totalling US$44 million under the federal U.S. stimulus package. Phase two is also expected to qualify for payments under the program.

Sundance A On February 8, 2011, TransCanada received from TransAlta Corporation (TransAlta) notice under the Sundance A PPA that TransAlta has determined that the Sundance 1 and 2 generating units cannot be economically repaired, replaced, rebuilt or restored and that TransAlta therefore seeks to terminate the PPA in respect of those units. TransCanada has not received any information that would validate TransAlta's determination that the units cannot be economically restored to service.

TransCanada has 10 business days from the date of TransAlta's notice to either agree with or dispute TransAlta's determination that the Sundance 1 and 2 generating units cannot be economically repaired, replaced, rebuilt or restored. TransCanada will assess any information provided by TransAlta during this 10-day period. If TransCanada disputes TransAlta's determination, the issue will be resolved using the dispute resolution procedure under the terms of the PPA.

In December 2010, the Sundance 1 and 2 generating units were withdrawn from service for testing. In January 2011, these same units were subject to a force majeure claim by TransAlta under the PPA. TransCanada has received insufficient information to make an assessment of TransAlta's force majeure claim and therefore has recorded revenues under the PPA as though this event was a normal plant outage.

Sundance B In second quarter 2010, Sundance B Unit 3 experienced an unplanned outage related to mechanical failure of certain generator components that the facility operator, TransAlta, has asserted is a force majeure event. TransCanada has received no information that validates a claim of force majeure and therefore has recorded revenues under the PPA as though this event was a normal plant outage. TransCanada is pursuing the remedies available to it under the terms of the PPA.

Coolidge At December 31, 2010, construction of the US$500 million Coolidge generating station located near Phoenix, Arizona was approximately 95 per cent complete and commissioning was approximately 80 per cent finished. The 575 MW, simple-cycle, natural gas-fired peaking power facility is expected to be in service in second quarter 2011. All of the power produced by the facility will be sold under a 20-year PPA to the Salt River Project Agricultural Improvement and Power District based in Phoenix.

Cartier Wind Construction activity on the 212 MW Gros-Morne and 58 MW Montagne-Sèche wind farms continued throughout 2010. The Montagne-Sèche project and the 101 MW first phase of the Gros-Morne project are expected to be operational by the end of 2011. The 111 MW second phase of the Gros-Morne project is expected to be operational by the end of 2012. Gros-Morne and Montagne-Sèche are the fourth and fifth wind farms of the Cartier Wind project in Québec. Once they are complete, Cartier Wind, which is 62 per cent owned by TransCanada, will be capable of producing 590 MW of electricity. All of the power produced by Cartier Wind is sold to Hydro-Québec under a 20-year PPA.

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

Ravenswood Subsequent to closing the acquisition of Ravenswood, TransCanada experienced a forced outage event related to Ravenswood's 972 MW Unit 30. The unit returned to service in May 2009. Insurers of the business interruption and physical damage claim have denied coverage. TransCanada has filed a claim against the insurers to enforce its rights under the insurance policies. Settlement discussions have not resolved the dispute over coverage and litigation proceedings are ongoing.

Power Transmission Line Projects In May 2010, TransCanada concluded a successful open season for the proposed Zephyr power transmission (Zephyr) project, during which it received signed agreements for the full 3,000 MW of wind-generated capacity with renewable energy developers in Wyoming. Support from key markets and a positive regulatory environment are necessary before the significant siting and permitting activities required to construct the project will commence. TransCanada anticipates making a decision in 2011 on whether to proceed with the project. The Zephyr project is a 1,609 km (1,000 miles), 500 kilovolt, high voltage direct current line (HVDC) expected to cost approximately US$3 billion. TransCanada expects commercial operations would commence in late 2016 or early 2017 if the project proceeds.

TransCanada closed the open season for the Chinook power transmission project in December 2010 without allocating capacity to Montana shippers. TransCanada is still developing the project and will continue discussions with Montana wind developers and other market participants to identify their future transmission requirements. The Chinook transmission project is a 1,609 km (1,000 miles), 500 kilovolt, HVDC transmission line expected to cost approximately US$3 billion.

ENERGY – BUSINESS RISKS

Fluctuating Power and Natural Gas Market Prices TransCanada operates in competitive power and natural gas markets in North America. Power and natural gas price volatility is caused by fluctuating supply and demand, and by general economic conditions. Sales of uncontracted power volumes into the spot market can be subject to price volatility, directly affecting earnings. To mitigate this risk, Energy commits a significant portion of its supply to sales contracts that are medium-term to long-term while retaining an amount of unsold supply in case of unexpected plant outages and in order to provide operational flexibility in managing the Company's portfolio of wholly owned assets. This unsold supply is subsequently sold under shorter-term forward arrangements or into the spot market and is exposed to fluctuating power and natural gas market prices. Additionally, as power sales contracts expire, new forward contracts are entered into at the prevailing market prices.

Bruce B volumes are subject to a floor price mechanism. When the spot market price is above the floor price, Bruce B's non-contracted volumes are subject to spot price volatility. When spot prices are below the floor price, Bruce B receives the floor price for all of its output. However, Bruce B's results during this period remain subject to the impact of fluctuating spot prices upon the settlement of fixed-price contract sales. The majority of contracted sales at Bruce B expired at December 31, 2010. All Bruce A output is sold into the Ontario wholesale power spot market under a fixed-price contract with the OPA and 100 per cent of Eastern Power sales volumes are sold under long-term contracts. As discussed, all Bruce A output after July 1, 2012 will be subject to spot market pricing if both Units 1 and 2 are not operating, which will continue until such time as both units are operational.

Energy's natural gas storage business is subject to fluctuating natural gas seasonal spreads generally determined by the differential in natural gas prices in the traditional summer injection and winter withdrawal seasons. As a result, the Company hedges capacity with a portfolio of capacity sales contracts and proprietary natural gas purchases and sales.

Capacity Payments The parameters that drive U.S. Power capacity prices are reset periodically and are affected by a number of factors including the cost of entering the market, reflected in administratively-set demand curves, available supply and fluctuations in forecast demand. With the downturn in the economy, there has been a decrease in demand that, combined with increased supply, has put downward pressure on capacity prices. On January 28, 2011, the FERC issued a decision in a rate filing made by the NYISO relating to the periodic reset of the demand curves. The FERC made several determinations related to such demand curves and ordered the NYISO to make revisions in a compliance filing no later than March 29, 2011. The FERC decision will likely result in higher demand curves that may positively affect capacity prices, but until the compliance filing and additional orders are issued and finalized, it is unclear what the impact on capacity prices will be.

Plant Availability Optimizing and maintaining plant availability is essential to the continued success of the Energy business. High levels of performance are achieved through the use of risk-based comprehensive preventative maintenance programs, prudent operating and capital investment, and a skilled workforce. Further mitigation is provided through the contractual obligations to TransCanada of its power suppliers under the Sundance and Sheerness PPAs, including the payment of market-based penalties related to availability requirements and by certain sales contracts that share operating risks with the purchaser. In the event a PPA power supplier experiences a verified force majeure event, TransCanada is not entitled to receive market-based penalties for the duration of the verified force majeure event and the monthly capacity payments paid to the supplier are eliminated during the same period. Unexpected plant outages, including unexpected delays in ending planned outages, could result in lower plant output and sales revenue, reduced capacity payments and margins, and increased maintenance costs. At certain times, unplanned outages may require power or natural gas purchases at market prices to ensure TransCanada meets its contractual obligations.

Weather Extreme temperature and weather events in North America and the Gulf of Mexico often create price volatility and variable demand for power and natural gas. These events may also restrict the availability of power and natural gas. Seasonal changes in temperature can also affect the efficiency and output capability of natural gas-fired power plants. Variability in wind speeds may impact the earnings of Energy's wind assets.

Hydrology TransCanada's power operations are subject to hydrology risk arising from the ownership of hydroelectric power generation facilities in the northeastern U.S. Weather changes, weather events, local river management and potential dam failures at these plants or upstream facilities pose potential risks to the Company.

Execution, Capital Cost and Permitting Energy's construction programs in Québec, Arizona and Ontario, including its investment in Bruce Power, are subject to execution, capital cost and permitting risks.

Regulation of Power Markets TransCanada operates in both regulated and deregulated power markets. As power markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively affect TransCanada as a generator and marketer of electricity. These may be in the form of market rule changes, price caps, emission controls, unfair cost allocations to generators and attempts by others to take out-of-market actions to build excess generation, all of which negatively affect the price of capacity or energy, or both. In addition, TransCanada's development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedules and costs. TransCanada continues to monitor regulatory issues and regulatory reform and participate in and lead related discussions.

Refer to the Risk Management and Financial Instruments section in this MD&A for information on additional risks and managing risks in the Energy business.

ENERGY – OUTLOOK

TransCanada expects that results from its Energy operations in 2011 will be materially consistent with those in 2010. There will be a positive earnings impact from a full year of earnings from Halton Hills and Kibby Wind, and a partial year of earnings from Coolidge, which is expected to be commissioned in second quarter 2011. Output from these plants, as well as a significant portion of output from Energy's other assets, has been sold under long-term contracts and provides a stable earnings base for the Energy business.

The Company expects the positive impact on earnings from the new assets coming into service will be tempered by results from Energy facilities whose output is sold under shorter-term forward arrangements or at spot prices. These facilities are expected to be affected to a greater degree by the current economic climate, which continues to have a negative impact on demand, liquidity and commodity and capacity prices.

Other factors such as plant availability, regulatory changes, weather, currency movements and overall stability of the energy industry can also affect 2011 EBIT. Refer to the Energy – Business Risks section in this MD&A for a complete discussion of these and other factors affecting the Energy Outlook.

Capital Expenditures Energy's total capital expenditures in 2010 were $1.1 billion. Energy's overall capital spending in 2011 is expected to be approximately $1 billion, including cash calls for the Bruce A refurbishment and restart project, and continued construction at Coolidge and Cartier Wind.

CORPORATE

Corporate had a Comparable EBIT loss of $99 million in 2010 compared to losses of $117 million and $104 million in 2009 and 2008, respectively. The decrease in the loss in 2010 was primarily due to lower support services and other corporate costs. The increase in the loss in 2009 compared to 2008 was primarily due to higher support services costs, reflecting a growing asset base.

OTHER INCOME STATEMENT ITEMS

INTEREST EXPENSE

Year ended December 31 *(millions of dollars)*	**2010**	2009	2008
Interest on long-term debt[1]			
Canadian dollar-denominated	**514**	548	523
U.S. dollar-denominated	**680**	645	479
Foreign exchange	**20**	92	36
	1,214	1,285	1,038
Other interest and amortizations	**74**	27	46
Capitalized interest	**(587)**	(358)	(141)
	701	954	943

[1] Includes interest on Junior Subordinated Notes.

Interest Expense in 2010 decreased $253 million to $701 million from $954 million in 2009. Interest on Canadian dollar-denominated debt decreased in 2010 compared to 2009 primarily due to debt maturities. Interest on U.S. dollar-denominated debt increased in 2010 compared to 2009 due to new debt issues of US$1.0 billion in September 2010, US$1.25 billion in June 2010 and US$2.0 billion in January 2009, partially offset by the impact of a weaker U.S. dollar. Other Interest and Amortization expense in 2010 was negatively affected by additional financing charges on committed credit facilities and increased losses from changes in the fair value of derivatives used to manage TransCanada's exposure to fluctuating interest rates, although the majority of these derivatives were settled prior to December 31, 2010. Interest Expense was positively impacted by higher capitalization of interest in 2010 relating to the Company's larger capital spending program primarily for the construction of Keystone and refurbishment and restart of Bruce A.

Interest Expense in 2009 increased $11 million to $954 million from $943 million in 2008. The increase in 2009 compared to 2008 reflected new Canadian debt issues of $700 million in February 2009 and $500 million in August 2008. Interest on U.S. dollar-denominated debt increased in 2009 compared to 2008 due to new debt issues of

US$2.0 billion in January 2009 and US$1.5 billion in August 2008. In addition, Interest Expense increased in 2009 compared to 2008 due to the impact of a stronger U.S. dollar on U.S. dollar-denominated interest. Increases in Interest Expense were significantly offset by higher capitalization of interest in 2009 relating to the Company's larger capital spending program primarily for the construction of Keystone, the acquisition of the remaining ownership interest in Keystone from ConocoPhillips, and refurbishment and restart of Bruce A.

Interest Income and Other was $94 million in 2010 compared to $121 million and $54 million in 2009 and 2008, respectively. The year-over-year changes primarily reflected the positive impact of a weakening U.S. dollar on the translation of U.S. dollar working capital balances throughout each year. The increase in 2009 compared to 2008 was also due to higher gains from derivatives used to manage the Company's exposure to foreign exchange rate fluctuation.

Income Taxes were $380 million, $387 million and $602 million in 2010, 2009, and 2008, respectively. The decrease of $7 million in 2010 compared to 2009 was primarily due to reduced pre-tax earnings, partially offset by positive income tax adjustments that reduced income taxes in 2009, including $30 million of favourable adjustments arising from a reduction in the Province of Ontario's corporate income tax rates. In 2010, the Company recorded a benefit in Current Income Taxes with an offsetting provision in Future Income Taxes as a result of bonus depreciation for U.S. income tax purposes on Keystone assets placed in service June 30, 2010. The decrease of $215 million in 2009 compared to 2008 was primarily due to reduced pre-tax earnings, higher income tax savings from income tax differentials and the positive income tax adjustments in 2009.

Non-Controlling Interests were $115 million in 2010 compared to $96 million and $130 million in 2009 and 2008, respectively. The $19 million increase in 2010 compared to 2009 was primarily due to increased PipeLines LP earnings as a result of higher revenues for Northern Border and the acquisition in 2009 of North Baja, partially offset by the impact of a weaker U.S. dollar in 2010. The decrease in 2009 compared to 2008 was primarily due to the non-controlling interests' portion of Portland's Calpine bankruptcy distributions in 2008, partially offset by higher PipeLines LP earnings and the impact of a stronger U.S. dollar in 2009.

LIQUIDITY AND CAPITAL RESOURCES

TransCanada's financial position remains sound and consistent with recent years as does its ability to generate cash in the short and long term to provide liquidity, maintain financial capacity and flexibility, and provide for planned growth. TransCanada's liquidity position remains solid, underpinned by predictable cash flow from operations, cash balances on hand from preferred share and debt issues, and unutilized committed revolving bank lines of US$1.0 billion, $2.0 billion and US$800 million, maturing in November 2011, December 2012 and December 2012, respectively. These facilities also support the Company's commercial paper programs. In addition, at December 31, 2010, TransCanada's proportionate share of unutilized capacity on committed bank facilities at TransCanada-operated affiliates was $111 million with maturity dates in 2011 and 2012. As at December 31, 2010, TransCanada had remaining capacity of $1.75 billion, $2.0 billion and US$1.75 billion under its equity, Canadian debt and U.S. debt shelf prospectuses, respectively. In lieu of making cash dividend payments, a portion of declared dividends for common and preferred shares are expected to be paid in common shares issued under the Company's DRP. TransCanada's liquidity, market and other risks are discussed further in the Risk Management and Financial Instruments section in this MD&A.

SUMMARIZED CASH FLOW

Year ended December 31 *(millions of dollars)*	**2010**	2009	2008
Funds generated from operations[1]	**3,331**	3,080	3,021
(Increase)/decrease in operating working capital	**(249)**	(90)	135
Net Cash Provided by Operations	**3,082**	2,990	3,156

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

HIGHLIGHTS

Investing Activities

- Capital expenditures and acquisitions, including assumed debt, totalled approximately $18 billion over the three-year period ending December 31, 2010.

Dividends

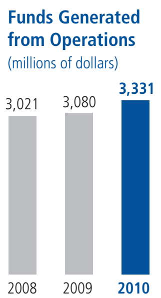
- TransCanada's Board of Directors declared a $0.42 per common share dividend for the quarter ending March 31, 2011, an increase of five per cent over the previous dividend amount. The Board of Directors also declared regular quarterly dividends of $0.2875 and $0.25 per Series 1 and 3 preferred share, respectively, for the quarter ending March 31, 2011 and $0.275 per Series 5 preferred share for the three-month period ending April 30, 2011.

CASH FLOW AND CAPITAL RESOURCES

Cash Generated from Operations

Net Cash Provided by Operations was $3.1 billion in 2010 compared to $3.0 billion and $3.2 billion in 2009 and 2008, respectively. Net Cash Provided by Operations reflects Funds Generated from Operations, net of changes in operating working capital.

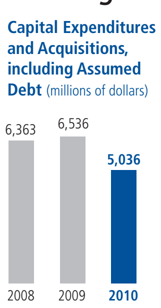
Funds Generated from Operations



Funds Generated from Operations were $3.3 billion in 2010 compared to $3.1 billion and $3.0 billion in 2009 and 2008, respectively. The increase in 2010 compared to 2009 was primarily due to an income tax benefit generated from bonus depreciation for U.S. tax purposes on Keystone assets placed in service on June 30, 2010 and increased cash from earnings. The increase in 2009 compared to 2008 was primarily due to increased cash from earnings, partially offset by higher pension contributions in 2009 and the $152 million after-tax Calpine bankruptcy distributions in 2008.

As at December 31, 2010, TransCanada's current liabilities were $5.7 billion and current assets were $3.2 billion resulting in a working capital deficiency of $2.5 billion. Excluding $2.1 billion of Notes Payable under the Company's commercial paper programs and draws on its line-of-credit facilities, TransCanada's working capital deficiency was $0.4 billion. The Company believes this shortfall can be managed through its ability to generate cash flow from operations as well as its ongoing access to capital markets.

Investing Activities



Capital expenditures totalled $5.0 billion in 2010 compared to $5.4 billion in 2009 and $3.1 billion in 2008. Expenditures in 2010, 2009 and 2008 related primarily to the construction of Keystone, the refurbishment and restart at Bruce A, construction of other new pipeline and power facilities, and the expansion and maintenance of existing pipelines.

In August 2009, the Company purchased ConocoPhillips' remaining interest of approximately 20 per cent in Keystone for US$553 million plus the assumption of US$197 million of short-term debt. In the first seven months of 2009, TransCanada solely funded $1.3 billion of cash calls for Keystone, resulting in the Company acquiring an incremental increase in ownership of approximately 18 per cent for $313 million. In 2008, the Company solely funded $362 million of cash calls, resulting in an incremental increase in ownership of approximately 12 per cent for $176 million. TransCanada's ownership interest in Keystone was approximately 62 per cent at December 31, 2008.

TransCanada acquired Ravenswood from National Grid plc in August 2008 for US$2.9 billion.

Financing Activities

In 2010, TransCanada issued $2.4 billion of long-term debt and its proportionate share of long-term debt issued by joint ventures was $177 million. Also in 2010, the Company reduced its long-term debt by $494 million and its proportionate share of the long-term debt of joint ventures by $254 million, and increased notes payable by $474 million. This financing activity included the items noted below.

At December 31, 2010, total committed revolving and demand credit facilities of $5.1 billion were available to support the Company's commercial paper programs and for general corporate purposes. These unsecured credit facilities included the following:

- a $2.0 billion committed, syndicated, revolving TransCanada PipeLines Limited (TCPL) credit facility, maturing December 2012. The facility was fully available at December 31, 2010;
- a US$300 million committed, syndicated, revolving credit facility, maturing February 2013. This facility is part of a US$1.0 billion TransCanada PipeLine USA Ltd. (TCPL USA) credit facility established in 2007 to partially finance the ANR acquisition and increased ownership in Great Lakes. At December 31, 2010, this facility was fully drawn;
- a US$1.0 billion committed, syndicated, revolving, extendible TransCanada Keystone Pipeline, L.P. credit facility, maturing November 2011 with a one-year extension at the option of the borrower. The facility was fully available at December 31, 2010 and supports a commercial paper program dedicated to funding a portion of capital expenditures for Keystone;
- a US$1.0 billion committed, syndicated, revolving TCPL USA credit facility, maturing December 2012, with a one-year extension at the option of the borrower. At December 31, 2010, US$200 million was drawn on this facility; and
- demand lines totalling $800 million, which support the issuance of letters of credit and provide additional liquidity. At December 31, 2010, the Company had used approximately $382 million of these demand lines for letters of credit.

In July 2009, TransCanada sold North Baja to PipeLines LP and received aggregate consideration totalling approximately US$395 million, including US$200 million in cash and 6,371,680 common units of PipeLines LP. The transaction resulted in TransCanada's ownership in PipeLines LP increasing to 42.6 per cent. Subsequent to the transaction, TransCanada's ownership in PipeLines LP decreased to 38.2 per cent due to PipeLines LP's public issuance of common units as discussed under the heading 2009 Equity Financing Activities in this section.

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

Short-Term Debt Financing Activities

In June 2008, TCPL executed an agreement with a syndicate of banks for a US$1.5 billion committed, unsecured, one-year bridge loan facility, which was extendible at the option of the Company for an additional six-month term. In August 2008, the Company used US$255 million from this facility to fund a portion of the Ravenswood acquisition and cancelled the remainder of the commitment. In February 2009, the US$255 million was repaid and the facility was cancelled.

2011 and 2010 Long-Term Debt Financing Activities

In September 2010, TCPL issued US$1.0 billion of Senior Notes maturing October 1, 2020 and bearing interest at 3.80 per cent. The notes were issued under a US$4.0 billion debt shelf prospectus filed in December 2009. The net proceeds of this offering were used to partially fund capital projects, for general corporate purposes and to repay short-term debt.

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

In January 2011, TCPL retired $300 million of 4.30 per cent Medium-Term Notes.

In February 2010, the Company retired US$120 million of 6.125 per cent Medium-Term Notes and in August 2010, the Company retired $130 million of 10.50 per cent debentures.

In September 2010, TQM retired $100 million of 7.53 per cent Series I bonds and $75 million of 3.906 per cent Series J bonds. In July 2010, TQM issued $100 million of bonds maturing in September 2017 and bearing interest at 4.25 per cent.

In April 2010, Iroquois retired US$200 million of Series I bonds bearing interest at 9.16 per cent and issued US$150 million of bonds maturing in April 2020 and bearing interest at 4.96 per cent.

2009 Long-Term Debt Financing Activities

In December 2009, TCPL filed a debt shelf prospectus qualifying the future issuance of up to US$4.0 billion of debt securities in the U.S. The prospectus replaced a US$3.0 billion debt base shelf prospectus filed in January 2009, which had remaining capacity of US$1.0 billion. At December 31, 2010, the December 2009 shelf prospectus had remaining capacity of US$1.75 billion.

In April 2009, TCPL filed a $2.0 billion Canadian Medium-Term Notes base shelf prospectus to replace a March 2007 $1.5 billion Canadian Medium-Term Notes base shelf prospectus, which expired in April 2009. No amounts have been issued under the April 2009 base shelf prospectus.

In February 2009, TCPL issued $300 million and $400 million of Medium-Term Notes maturing in February 2014 and February 2039, respectively, and bearing interest at 5.05 per cent and 8.05 per cent, respectively. The proceeds were used to fund the Alberta System and Canadian Mainline rate bases. These notes were issued by way of pricing supplements under a $1.5 billion Canadian debt base shelf prospectus filed in March 2007.

In January 2009, TCPL issued US$750 million and US$1.25 billion of Senior Unsecured Notes maturing in January 2019 and January 2039, respectively, and bearing interest at 7.125 per cent and 7.625 per cent, respectively. The proceeds were used to partially fund capital projects, retire maturing debt obligations and for general corporate purposes. These notes were issued by way of a prospectus supplement under a US$3.0 billion debt base shelf prospectus filed by TCPL in January 2009.

In October 2009, the Company retired $250 million of 10.625 per cent debentures.

In February 2009, the Company retired $200 million of 4.10 per cent Medium-Term Notes, and in January 2009, the Company retired US$227 million of 6.49 per cent Medium-Term Notes.

In September 2009, TQM issued $75 million of bonds maturing in September 2014 and bearing interest at 4.05 per cent. In August 2009, TQM retired $100 million of 6.50 per cent Series H bonds.

In August 2009, Northern Border issued US$100 million of Senior Unsecured Notes maturing in August 2016 and bearing interest at 6.24 per cent. In September 2009, Northern Border retired US$200 million of 7.75 per cent Senior Notes.

In May 2009, Iroquois issued US$140 million of Senior Unsecured Notes maturing in May 2019 and bearing interest at 6.63 per cent.

2008 Long-Term Debt Financing Activities

In August 2008, TCPL issued $500 million of Medium-Term Notes maturing in August 2013 and bearing interest at 5.05 per cent. The proceeds from these notes were used to partially fund the Alberta System's capital program and for general corporate purposes. These notes were issued by way of pricing supplement under a $1.5 billion Canadian debt base shelf prospectus filed in March 2007.

In August 2008, TCPL issued US$850 million and US$650 million of Senior Unsecured Notes maturing in August 2018 and August 2038, respectively, and bearing interest at 6.50 per cent and 7.25 per cent, respectively. The proceeds from the notes were used to partially fund the Ravenswood acquisition and for general corporate purposes. The notes were issued by way of a prospectus supplement under a US$2.5 billion debt base shelf prospectus filed in September 2007, which was fully utilized following these issuances.

In June 2008, the Company retired $256 million of 5.84 per cent Medium-Term Notes and a $100 million 11.85 per cent debenture. In January 2008, the Company retired $105 million of 6.0 per cent Medium-Term Notes.

2010 Equity Financing Activities

In June 2010, TransCanada completed a public offering of 14 million Series 5 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares, under its September 2009 base shelf prospectus, discussed below. The preferred shares were issued at a price of $25.00 per share, resulting in gross proceeds of $350 million including the underwriters' option. The holders of the Series 5 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.10 per share, payable quarterly, yielding 4.4 per cent per annum for the initial five and a half year period ending January 30, 2016. The dividend rate will reset on January 30, 2016 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 1.54 per cent. The Series 5 preferred shares are redeemable by TransCanada on January 30, 2016 and on January 30 of every fifth year thereafter at a price of $25.00 per share plus all accrued and unpaid dividends. The preferred shareholders are eligible to participate in the Company's DRP. The net proceeds of this offering were used to partially fund capital projects, for general corporate purposes and to repay short-term debt.

The Series 5 preferred shareholders have the right to convert their shares into Series 6 cumulative redeemable first preferred shares on January 30, 2016 and on January 30 of every fifth year thereafter. The holders of Series 6 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.54 per cent.

In March 2010, TransCanada completed a public offering of 14 million Series 3 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares, under its September 2009 base shelf prospectus, discussed below. The preferred shares were issued at a price of $25.00 per share, resulting in gross proceeds of $350 million including the underwriters' option. The holders of the Series 3 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.00 per share, payable quarterly, yielding 4.0 per cent per annum for the initial five-year period ending June 30, 2015. The dividend rate will reset on June 30, 2015 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 1.28 per cent. The Series 3 preferred shares are redeemable by TransCanada on June 30, 2015 and on June 30 of every fifth year thereafter at a price of $25.00 per share plus all accrued and unpaid dividends. The preferred shareholders are eligible to participate in the Company's DRP. The net proceeds of this offering were used to partially fund capital projects, for general corporate purposes and to repay short-term debt.

The Series 3 preferred shareholders have the right to convert their shares into Series 4 cumulative redeemable first preferred shares on June 30, 2015 and on June 30 of every fifth year thereafter. The holders of Series 4 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.28 per cent.

2009 Equity Financing Activities

In September 2009, TransCanada completed a public offering of 22 million Series 1 cumulative redeemable first preferred shares under a prospectus supplement to its September 2009 base shelf prospectus, discussed below, for gross proceeds of $550 million. The holders of the Series 1 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.15 per share, payable quarterly, yielding 4.6 per cent per annum for the initial five-year period ending December 31, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield plus 1.92 per cent. The preferred shares are redeemable by TransCanada on or after December 31, 2014 at a price of $25.00 per share plus all accrued and unpaid dividends. The preferred shareholders are eligible to participate in the Company's DRP. The net proceeds of the offering were used to partially fund capital projects, for general corporate purposes and to repay short-term debt.

The Series 1 preferred shareholders have the right to convert their shares into Series 2 cumulative redeemable first preferred shares on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.92 per cent.

In September 2009, TransCanada filed a base shelf prospectus qualifying the future issuance of up to $3.0 billion of common shares, first or second preferred shares, or subscription receipts in Canada and the U.S. until October 2011. This base shelf prospectus replaced the base shelf prospectus filed in July 2008, which was depleted by the common share issuance in June 2009. The Company had $1.75 billion available under the September 2009 prospectus at December 31, 2010.

In June 2009, TransCanada completed a public offering of 58.4 million common shares at a purchase price of $31.50 per share. The issue, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.8 billion. The proceeds were used by TransCanada to partially fund capital projects, including the acquisition of the remaining interest in Keystone, for general corporate purposes and to repay short-term debt.

In November 2009, PipeLines LP completed a public offering of five million common units at a price of US$38.00 per unit, resulting in net proceeds to PipeLines LP of US$182 million. TransCanada contributed an additional US$4 million to maintain its general partnership interest but did not purchase any units. Upon completion of this offering, TransCanada's ownership interest in PipeLines LP was 38.2 per cent.

2008 Equity Financing Activities

In fourth quarter 2008, TransCanada completed a public offering of 35.1 million common shares at a purchase price of $33.00 per share. The issue, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.2 billion. The proceeds of the offering were used by TransCanada to partially fund its capital projects, including Keystone, for general corporate purposes and to repay short-term debt. The common shares were issued under a prospectus supplement to the base shelf prospectus filed in July 2008.

In July 2008, TransCanada filed a base shelf prospectus in Canada and the U.S. qualifying the future issuance of up to $3.0 billion of common shares, preferred shares or subscription receipts in Canada and the U.S. until August 2010. The base shelf prospectus replaced a base shelf prospectus filed in January 2007.

In May 2008, TransCanada completed a public offering of 34.7 million common shares at a purchase price of $36.50 per share. The issue, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.3 billion. These proceeds were used to partially fund the Ravenswood acquisition and the Company's capital projects, and for general corporate purposes. The common shares were issued under a prospectus supplement to the base shelf prospectus filed in January 2007.

Dividend Reinvestment and Share Purchase Plan

TransCanada's Board of Directors has authorized the issuance of common shares from treasury at a discount to participants in the Company's DRP. Under this plan, eligible holders of common or preferred shares of TransCanada and preferred shares of TCPL may reinvest their dividends and make optional cash payments to obtain TransCanada common shares. The DRP shares are provided to the participants at a discount to the average market price in the five days before dividend payment. The discount was set at three per cent in 2009 and 2010, and was reduced to two per cent commencing with the dividends declared in February 2011. The discount was set at two per cent for 2008 and was increased to three per cent commencing with the dividend declared in February 2009. The Company reserves the right to alter the discount or to satisfy its DRP obligations by instead purchasing shares on the open market at any time. In 2010, dividends of $378 million were paid (2009 – $254 million; 2008 – $218 million) through the issuance of 11 million (2009 – 8 million; 2008 – 6 million) common shares from treasury in accordance with the DRP.

Dividends

Cash dividends on common shares amounting to $710 million were paid in 2010 (2009 – $722 million; 2008 – $577 million). In addition, cash dividends of $44 million were paid on preferred shares in 2010 (2009 – $6 million). The decrease in common share dividends paid in 2010 was primarily due to increased participation in the DRP in lieu of cash dividends, which grew to $378 million in 2010 from $254 million in 2009, partially offset by a greater number of shares outstanding and an increase in the dividend per share amount in 2010. The increase in common share dividends paid in 2009 from 2008 was primarily due to a greater number of shares outstanding and an increase in the dividend per share amount in 2009, partially offset by the Company's issuance in 2009 of $254 million (2008 – $218 million) of common shares from treasury under the DRP in lieu of cash dividends. The increase in preferred share dividends paid in 2010 from 2009 was primarily due to a full year of preferred share dividend payments in 2010 on preferred shares issued in September 2009 and the preferred share issuances in 2010.

In February 2011, TransCanada's Board of Directors approved an increase in the quarterly common share dividend payment to $0.42 per share from $0.40 per share for the quarter ending March 31, 2011. This was the eleventh consecutive year in which the dividend was increased, resulting in a per share dividend that has more than doubled since 2000. In addition, the Board of Directors declared quarterly dividends of $0.2875 and $0.25 per Series 1 and 3 preferred share, respectively, for the quarter ending March 31, 2011 and $0.275 per Series 5 preferred share for the three-month period ended April 30, 2011.

CONTRACTUAL OBLIGATIONS

Obligations and Commitments

At December 31, 2010, the Company had $17.9 billion of total long-term debt and $1.0 billion of Junior Subordinated Notes, compared to $16.7 billion of total long-term debt and $1.0 billion of Junior Subordinated Notes at December 31, 2009. TransCanada's share of the total long-term debt of joint ventures, including capital lease obligations, was $0.9 billion at December 31, 2010, compared to $1.0 billion at December 31, 2009. Total Notes Payable, including TransCanada's proportionate share of the notes payable of joint ventures, were $2.1 billion at December 31, 2010 and $1.7 billion at December 31, 2009. TransCanada has provided certain pro-rata guarantees related to the capital lease and performance obligations of Bruce Power and certain other partially owned entities.

CONTRACTUAL OBLIGATIONS

		Payments Due by Period			
Year ended December 31 *(millions of dollars)*	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt[1]	19,566	943	2,122	2,085	14,416
Capital lease obligations	207	16	38	48	105
Operating leases[2]	784	74	150	142	418
Purchase obligations	9,599	2,393	2,102	1,527	3,577
Other long-term liabilities reflected on the balance sheet	976	16	32	37	891
	31,132	3,442	4,444	3,839	19,407

(1) Includes Junior Subordinated Notes and Long-Term Debt of Joint Ventures, excluding capital lease obligations.

(2) Represents future annual payments, net of sub-lease receipts, for various premises, services and equipment. The operating lease agreements for premises, services and equipment expire at various dates through 2052 with an option to renew certain lease agreements for one to 10 years.

TransCanada's commitments under the Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Future payments under these PPAs have been excluded from operating leases in the above table, as these payments are dependent upon plant availability among other factors. TransCanada's share of power purchased under the PPAs in 2010 was $363 million (2009 – $384 million; 2008 – $398 million).

At December 31, 2010, scheduled principal repayments and interest payments related to long-term debt and the Company's proportionate share of the long-term debt of joint ventures were as follows:

PRINCIPAL REPAYMENTS

		Payments Due by Period			
Year ended December 31 *(millions of dollars)*	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt	17,922	894	2,012	2,034	12,982
Junior subordinated notes	985	–	–	–	985
Long-term debt of joint ventures	659	49	110	51	449
	19,566	943	2,122	2,085	14,416

INTEREST PAYMENTS

		Payments Due by Period			
Year ended December 31 *(millions of dollars)*	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt	16,721	1,140	2,190	1,973	11,418
Junior subordinated notes(1)	410	63	126	126	95
Long-term debt of joint ventures	381	48	90	80	163
	17,512	1,251	2,406	2,179	11,676

(1) Payments were calculated assuming the notes would be redeemed after 10 years.

At December 31, 2010, the Company's approximate future purchase obligations were as follows:

PURCHASE OBLIGATIONS[1]

Year ended December 31 (millions of dollars)	Total	Payments Due by Period: Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Natural Gas Pipelines					
Transportation by others[2]	651	189	197	111	154
Capital expenditures[3][4]	239	174	65	–	–
Other	2	1	1	–	–
Oil Pipelines					
Capital expenditures[3][5]	1,172	783	389	–	–
Other	49	4	8	8	29
Energy					
Commodity purchases[6]	5,467	547	1,158	1,201	2,561
Capital expenditures[3][7]	567	541	26	–	–
Other[8]	1,420	133	251	204	832
Corporate					
Information technology and other	32	21	7	3	1
	9,599	2,393	2,102	1,527	3,577

(1) The amounts in this table exclude funding contributions to pension plans.

(2) Rates are based primarily on known 2010 levels. Beyond 2010, demand rates are subject to change. The purchase obligations in the table are based on known or contracted demand volumes only and exclude commodity charges incurred when volumes flow.

(3) Amounts are estimates and are subject to variability based on timing of construction and project enhancements. The Company expects to fund capital projects with cash from operations, the issuance of senior debt and subordinated capital, and through portfolio management.

(4) Capital expenditures primarily relate to the construction costs of the Alberta System expansion, Guadalajara and other natural gas pipeline projects.

(5) Capital expenditures relate to the Keystone U.S. Gulf Coast Expansion.

(6) Commodity purchases include fixed and variable components. The variable components are estimates and are subject to variability in plant production, market prices and regulatory tariffs.

(7) Capital expenditures primarily relate to TransCanada's share of the construction and development costs of Bruce Power and Cartier Wind.

(8) Includes estimates of certain amounts that are subject to change depending on plant-fired hours, the consumer price index, actual plant maintenance costs, plant salaries and changes in regulated rates for transportation.

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business. Potential future commitments are discussed in the Opportunities and Developments sections for Natural Gas Pipelines, Oil Pipelines and Energy in this MD&A.

In 2011, TransCanada expects to make funding contributions of approximately $98 million to its defined benefit pension plans and approximately $28 million to the Company's other post-retirement benefit plans, savings plan and defined contribution pension plans. This is consistent with total funding contributions of $127 million in 2010. TransCanada's proportionate share of funding contributions expected to be made by joint ventures to their respective pension and other post-retirement benefit plans in 2011 is approximately $87 million and $7 million, respectively, compared to total contributions of $58 million in 2010.

The next actuarial valuation for the Company's pension and other post-retirement benefit plans will be carried out as at January 1, 2012. Based on current market conditions, TransCanada expects funding requirements for these plans to continue at the anticipated 2011 level for the next several years to amortize solvency deficiencies in addition to normal costs. The Company's 2011 net benefit cost is expected to increase from 2010 primarily due to a lower projected discount rate. However, future net benefit costs and the amount of funding contributions will be dependent on various factors, including investment returns achieved on plan assets, the level of interest rates, changes to plan design and actuarial assumptions, actual plan experience versus projections and amendments to pension plan regulations and legislation. Increases in the level of required plan funding are not expected to have a material impact on the Company's liquidity.

Bruce Power

Bruce A has signed commitments to third-party suppliers related to refurbishing and restarting Units 1 and 2. TransCanada's share of these signed commitments is $205 million. The Company expects $193 million and $12 million to be paid in 2011 and 2012, respectively.

Contingencies

TransCanada is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2010, the Company accrued approximately $59 million (2009 – $67 million) related to operating facilities, which represents the estimated amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

TransCanada and its subsidiaries are subject to various legal proceedings and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

Guarantees

TransCanada and its joint venture partners on Bruce Power, Cameco Corporation and BPC, have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, a lease agreement and contractor services. The guarantees have terms ranging from 2018 to perpetuity. In addition, TransCanada and BPC have each severally guaranteed one-half of certain contingent financial obligations related to an agreement with the OPA to refurbish and restart Bruce A power generation units. The guarantees were provided as part of the reorganization of Bruce Power in 2005 and have terms ending in 2018 and 2019. TransCanada's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated to be $739 million at December 31, 2010. The fair value of these Bruce Power guarantees is estimated to be $42 million. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to redelivery of natural gas, PPA payments and the payment of liabilities. TransCanada's share of the potential exposure under these guarantees was estimated at December 31, 2010 to range from $227 million to a maximum of $539 million. The fair value of these guarantees is estimated to be $9 million, which has been included in Deferred Amounts. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

FINANCIAL RISKS AND FINANCIAL INSTRUMENTS

Risk Management Overview

TransCanada has exposure to market risk, counterparty credit risk and liquidity risk. TransCanada engages in risk management activities with the objective of protecting earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TransCanada's risks and related exposures are in line with the Company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by risk management and internal audit personnel. The Board of Directors' Audit Committee oversees how management monitors compliance with risk management policies and procedures, and oversees management's review of the adequacy of the financial risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of financial risk management controls and procedures, the results of which are reported to the Audit Committee.

Market Risk

The Company constructs and invests in large infrastructure projects, purchases and sells energy commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. These activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which affect the Company's earnings and the value of the financial instruments it holds.

The Company uses derivatives as part of its overall risk management strategy to manage the exposure to market risk that results from these activities. Derivative contracts used to manage market risk generally consist of the following:

- Forwards and futures contracts – contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TransCanada enters into foreign exchange and commodity forwards and futures to mitigate the impact of volatility in foreign exchange rates and commodity prices.
- Swaps – contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.
- Options – contractual agreements to convey the right, but not the obligation, of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.

Where possible, derivative financial instruments are designated as hedges, but in some cases derivatives do not meet the specific criteria for hedge accounting treatment and are accounted for at fair value with changes in fair value recorded in Net Income in the period of change. This may expose the Company to increased variability in reported operating results because the fair value of the derivative instruments can fluctuate significantly from period to period. However, the Company enters into the arrangements as they are considered to be effective economic hedges.

Commodity Price Risk

The Company is exposed to commodity price movements as part of its normal business operations, particularly in relation to the prices of electricity, natural gas and oil products. A number of strategies are used to mitigate these exposures, including the following:

- Subject to its overall risk management strategy, the Company commits a portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to mitigate price risk in its asset portfolio.

- The Company purchases a portion of the natural gas and oil products required for its power plants or enters into contracts that base the sale price of electricity on the cost of natural gas, effectively locking in a margin. A significant portion of the electricity needed to fulfil the Company's power sales commitments is fulfilled through power generation or purchased through contracts, thereby reducing the Company's exposure to fluctuating commodity prices.
- The Company enters into offsetting or back-to-back positions using derivative financial instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

The Company assesses its commodity contracts and derivative instruments used to manage commodity risk to determine the appropriate accounting treatment. Contracts, with the exception of leases, have been assessed to determine whether they or certain aspects of them meet the definition of a derivative. Certain commodity purchase and sale contracts are derivatives but fair value accounting is not required, as they were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected purchase, sale or usage requirements and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain exemptions.

Natural Gas Storage Commodity Price Risk

TransCanada manages its exposure to seasonal natural gas price spreads in its non-regulated Natural Gas Storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TransCanada simultaneously enters 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 natural gas price movements. Fair value adjustments recorded each period on proprietary natural gas inventory in storage and on these forward contracts are not representative of the amounts that will be realized on settlement.

At December 31, 2010, the fair value of proprietary natural gas inventory in storage, measured using a weighted average of forward prices for the following four months less selling costs, was $49 million (2009 – $73 million). The change in fair value of proprietary natural gas inventory in storage in 2010 resulted in pre-tax unrealized losses of $16 million (2009 – gains of $3 million; 2008 – losses of $7 million), which were recorded as a decrease to Revenues and to Inventories. The change in fair value of natural gas forward purchase and sales contracts in 2010 resulted in pre-tax unrealized gains of $6 million (2009 – losses of $2 million; 2008 – gains of $7 million), which were recorded as an increase to Revenues and to Inventories.

Foreign Exchange and Interest Rate Risk

Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and market interest rates.

TransCanada's earnings from its Natural Gas Pipelines and Energy segments are generated in U.S. dollars and, therefore, fluctuations in the value of the Canadian dollar relative to the U.S. dollar can affect TransCanada's earnings. This foreign exchange impact is partially offset by U.S. dollar-denominated financing costs and by the Company's hedging activities. TransCanada has a greater exposure to U.S. currency fluctuations than in prior years due to growth in its U.S. operations, partially offset by increased levels of U.S. dollar-denominated financing costs.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to its debt and other U.S. dollar-denominated transactions, and to manage the interest rate exposures of the Alberta System and Foothills operations. Certain of the realized gains and losses on these derivatives are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers in accordance with the terms of the shipping agreements.

TransCanada has floating interest rate debt which subjects it to interest rate cash flow risk. The Company uses a combination of interest rate swaps and options to manage its exposure to this risk.

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 December 31, 2010, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $9.8 billion (US$9.8 billion) (2009 – $7.9 billion (US$7.6 billion)) and a fair value of $11.3 billion (US$11.4 billion) (2009 – $9.8 billion (US$9.3 billion)). At December 31, 2010, $181 million was included in Intangibles and Other Assets (2009 – $96 million) for the fair value of the forwards, swaps and options used to hedge the Company's net U.S. dollar investment in foreign operations.

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

Asset/(Liability)

	2010		2009	
December 31 *(millions of dollars)*	**Fair Value[1]**	**Notional or Principal Amount**	Fair Value[1]	Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2011 to 2016)	**179**	**US 2,800**	86	US 1,850
U.S. dollar forward foreign exchange contracts (maturing 2011)	**2**	**US 100**	9	US 765
U.S. dollar options (matured in 2010)	**–**	**–**	1	US 100
	181	**US 2,900**	96	US 2,715

(1) Fair values equal carrying values.

VaR Analysis

TransCanada uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its liquid open positions. VaR represents the potential change in pre-tax earnings over a given holding period for a specified confidence level. The VaR number used by TransCanada is calculated assuming a 95 per cent confidence level that the daily change resulting from normal market fluctuations in its liquid open positions will not exceed the reported VaR. The VaR methodology is a statistically calculated, probability-based approach that takes into consideration market volatilities as well as risk diversification by recognizing offsetting positions and correlations among products and markets. Risks are measured across all products and markets, and risk measures are aggregated to arrive at a single VaR number.

There is currently no uniform industry methodology for estimating VaR. The use of VaR has limitations because it is based on historical correlations and volatilities in commodity prices, interest rates and foreign exchange rates, and assumes that future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR.

TransCanada's estimation of VaR includes wholly owned subsidiaries and incorporates relevant risks associated with each market or business unit. The calculation does not include the regulated natural gas pipelines, as the nature of the rate-regulated pipeline business reduces the impact of market risks. TransCanada's Board of Directors has established a

VaR limit, which is monitored on an ongoing basis as part of the Company's risk management policy. TransCanada's consolidated VaR was $12 million at December 31, 2010 (2009 – $12 million).

Counterparty Credit Risk

Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of its contracts with the Company.

Counterparty credit risk is managed through established credit management techniques, including conducting financial and other assessments to establish and monitor a counterparty's creditworthiness, setting exposure limits, monitoring exposures against these limits, using master netting arrangements and obtaining financial assurances where warranted. In general, financial assurances include guarantees, letters of credit and cash. The Company monitors and manages its concentration of counterparty credit risk on an ongoing basis. The Company believes these measures minimize its counterparty credit risk but there is no certainty that they will protect it against all material losses.

TransCanada's maximum counterparty credit exposure with respect to financial instruments at the Balance Sheet date, without taking into account security held, consisted of accounts receivable, the fair value of derivative assets and notes, loans and advances receivable. The carrying amounts and fair values of these financial assets, except amounts for derivative assets, are included in Accounts Receivable and Other in the Non-Derivative Financial Instruments Summary table located in the Fair Values section 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 that are investment grade. At December 31, 2010, there were no significant amounts past due or impaired.

At December 31, 2010, the Company had a credit risk concentration of $317 million (2009 – $334 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.

TransCanada has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, critical liquidity in the foreign exchange derivative, interest rate derivative and energy wholesale markets, and letters of credit to mitigate TransCanada's exposure to non-creditworthy counterparties.

As a level of uncertainty continues to exist in the global financial markets, TransCanada continues to closely monitor and reassess the creditworthiness of its counterparties. This has resulted in TransCanada reducing or mitigating its exposure to certain counterparties where it was deemed warranted and permitted under contractual terms. As part of its ongoing operations, TransCanada must balance its market and counterparty credit risks when making business decisions.

Calpine and certain of its subsidiaries filed for bankruptcy protection in Canada or the U.S. in 2005. Gas Transmission Northwest Corporation (GTNC) and Portland reached agreements with Calpine for allowed unsecured claims in the Calpine bankruptcy. In February 2008, GTNC and Portland received initial distributions of 9.4 million common shares and 6.1 million common shares, respectively, of Calpine, which represented approximately 85 per cent of their agreed-upon claims. In 2008, these shares were sold into the open market and resulted in total pre-tax gains of $279 million. Claims by NGTL and Foothills Pipe Lines (South B.C.) Ltd. for $32 million and $44 million, respectively, were received in cash in January 2008 and were passed onto shippers on these systems in 2008 and 2009. In 2010, the Company accrued an additional pre-tax gain of $15 million related to expected future proceeds with respect to the GTNC and Portland claims.

Liquidity Risk

Liquidity risk is the risk that TransCanada will not be able to meet its financial obligations as they become due. The Company's approach to managing liquidity risk is to ensure that sufficient cash and credit facilities are available to meet its operating, financing and capital expenditure obligations when due, under both normal and stressed economic conditions.

Management continuously forecasts cash flows for a period of 12 months to identify financing requirements. These requirements are then managed through a combination of committed and demand credit facilities and access to capital markets, as discussed in the Capital Management section below.

At December 31, 2010, the Company had unutilized committed revolving bank lines of US$1.0 billion, $2.0 billion and US$0.8 billion maturing in November 2011, December 2012 and December 2012, respectively. The Company has also maintained continuous access to the Canadian commercial paper market on competitive terms.

Capital Management

The primary objective of capital management is to ensure TransCanada has strong credit ratings to support its businesses and maximize shareholder value. In 2010, the overall objective and policy for managing capital remained unchanged from the prior year.

TransCanada manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. The Company's management considers its capital structure to consist of net debt, Non-Controlling Interests and Shareholders' Equity. Net debt comprises Notes Payable, Long-Term Debt and Junior Subordinated Notes less Cash and Cash Equivalents. Net debt only includes obligations that the Company controls and manages. Consequently, it does not include Cash and Cash Equivalents, Notes Payable and Long-Term Debt of TransCanada's joint ventures.

The total capital managed by the Company was as follows:

December 31 *(millions of dollars)*	**2010**	2009
Notes payable	**2,081**	1,678
Long-term debt	**17,922**	16,664
Junior subordinated notes	**985**	1,036
Cash and cash equivalents	**(660)**	(896)
Net debt	**20,328**	18,482
Non-controlling interests	**1,157**	1,174
Shareholders' equity	**16,727**	15,759
Total equity	**17,884**	16,933
	38,212	35,415

Fair Values

Certain financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Intangibles and Other Assets, Notes Payable, Accounts Payable, Accrued Interest and Deferred Amounts have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. The fair value of foreign exchange and interest rate derivatives has been calculated using year-end market rates and applying a discounted cash flow valuation model. The fair value of power, natural gas and oil products derivatives, and of available-for-sale investments, has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used.

The fair value of the Company's Notes Receivable is calculated by discounting future payments of interest and principal using forward interest rates. Long-Term Debt was estimated based on quoted market prices for the same or similar debt instruments. Credit risk has been taken into consideration when calculating the fair value of derivatives, Notes Receivable and Long-Term Debt.

Non-Derivative Financial Instruments Summary

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

	2010		2009	
December 31 *(millions of dollars)*	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial Assets[1]				
Cash and cash equivalents	**764**	**764**	997	997
Accounts receivable and other[2][3]	**1,555**	**1,595**	1,432	1,483
Available-for-sale assets[2]	**20**	**20**	23	23
	2,339	**2,379**	2,452	2,503
Financial Liabilities[1][3]				
Notes payable	**2,092**	**2,092**	1,687	1,687
Accounts payable and deferred amounts[4]	**1,436**	**1,436**	1,538	1,538
Accrued interest	**367**	**367**	377	377
Long-term debt	**17,922**	**21,523**	16,664	19,377
Junior subordinated notes	**985**	**992**	1,036	976
Long-term debt of joint ventures	**866**	**971**	965	1,025
	23,668	**27,381**	22,267	24,980

(1) Consolidated Net Income in 2010 included gains of $8 million (2009 – gains of $6 million) for fair value adjustments related to interest rate swap agreements on US$250 million (2009 – US$250 million) of long-term debt. There were no other unrealized gains or losses from fair value adjustments to the financial instruments.

(2) At December 31, 2010, the Consolidated Balance Sheet included financial assets of $1,271 million (2009 – $966 million) in Accounts Receivable, $40 million (2009 – nil) in Other Current Assets and $264 million (2009 – $489 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost except for $250 million (2009 – $250 million) of Long-Term Debt, which is adjusted to fair value.

(4) At December 31, 2010, the Consolidated Balance Sheet included financial liabilities of $1,406 million (2009 – $1,513 million) in Accounts Payable and $30 million (2009 – $25 million) in Deferred Amounts.

The following tables detail the remaining contractual maturities for TransCanada's non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2010:

Contractual Repayments of Financial Liabilities[1]

(millions of dollars)	Total	Payments Due by Period 2011	2012 and 2013	2014 and 2015	2016 and Thereafter
Notes payable	2,092	2,092	–	–	–
Long-term debt	17,922	894	2,012	2,034	12,982
Junior subordinated notes	985	–	–	–	985
Long-term debt of joint ventures	866	65	148	99	554
	21,865	3,051	2,160	2,133	14,521

(1) The anticipated timing of settlement of derivative contracts is presented in the Derivatives Financial Instrument Summary below.

Interest Payments on Financial Liabilities

(millions of dollars)	Total	Payments Due by Period 2011	2012 and 2013	2014 and 2015	2016 and Thereafter
Long-term debt	16,721	1,140	2,190	1,973	11,418
Junior subordinated notes	410	63	126	126	95
Long-term debt of joint ventures	381	48	90	80	163
	17,512	1,251	2,406	2,179	11,676

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2010 is as follows:

December 31	2010			
(all amounts in millions unless otherwise indicated)	**Power**	**Natural Gas**	**Foreign Exchange**	**Interest**
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	$169	$144	$8	$20
Liabilities	$(129)	$(173)	$(14)	$(21)
Notional Values				
Volumes[3]				
Purchases	15,610	158	–	–
Sales	18,114	96	–	–
Canadian dollars	–	–	–	736
U.S. dollars	–	–	US 1,479	US 250
Cross-currency	–	–	47/US 37	–
Net unrealized (losses)/gains in the year[4]	$(32)	$27	$4	$43
Net realized gains/(losses) in the year[4]	$77	$(42)	$36	(74)
Maturity dates	2011-2015	2011-2015	2011-2012	2011-2016
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	$112	$5	$–	$8
Liabilities	$(186)	$(19)	$(51)	$(26)
Notional Values				
Volumes[3]				
Purchases	16,071	17	–	–
Sales	10,498	–	–	–
U.S. dollars	–	–	US 120	US 1,125
Cross-currency	–	–	136/US 100	–
Net realized losses in the year[4]	$(9)	$(35)	$–	$(33)
Maturity dates	2011-2015	2011-2013	2011-2014	2011-2015

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

(2) Fair values equal carrying values.

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

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

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $8 million and a notional amount of US$250 million. In 2010, net realized gains on fair value hedges were $4 million and were included in Interest Expense. In 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) In 2010, Net Income included a gain of $1 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. In 2010, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

The anticipated timing of settlement of the derivative contracts assumes constant commodity prices, interest rates and foreign exchange rates from December 31, 2010. Settlements will vary based on the actual value of these factors at the date of settlement. The anticipated timing of settlement of these contracts is as follows:

Year ended December 31 *(millions of dollars)*	Total	2011	2012 and 2013	2014 and 2015	2016 and Thereafter
Derivative financial instruments held for trading					
Assets	341	221	102	17	1
Liabilities	(337)	(191)	(121)	(24)	(1)
Derivative financial instruments in hedging relationships					
Assets	306	76	204	26	–
Liabilities	(282)	(146)	(120)	(16)	–
	28	(40)	65	3	–

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2009 is as follows:

December 31 (*all amounts in millions unless otherwise indicated*)	2009 Power	Natural Gas	Oil Products	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading					
Fair Values[1]					
Assets	$150	$107	$5	$–	$25
Liabilities	$(98)	$(112)	$(5)	$(66)	$(68)
Notional Values					
Volumes[2]					
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 year[3]	$3	$(5)	$1	$3	$27
Net realized gains/(losses) in the year[3]	$70	$(76)	$–	$36	$(22)
Maturity dates	2010-2015	2010-2014	2010	2010-2012	2010-2018
Derivative Financial Instruments in Hedging Relationships[4][5]					
Fair Values[1]					
Assets	$175	$2	$–	$–	$15
Liabilities	$(148)	$(22)	$–	$(43)	$(50)
Notional Values					
Volumes[2]					
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 year[3]	$156	$(29)	$–	$–	$(37)
Maturity dates	2010-2015	2010-2014	–	2010-2014	2010-2020

(1) Fair values equal carrying values.

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

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

(4) 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. In 2009, realized gains on fair value hedges were $4 million and were included in Interest Expense. In 2009, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(5) In 2009, Net Income included losses 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. In 2009, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

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

December 31 *(millions of dollars)*	**2010**	2009
Current		
Other current assets	**273**	315
Accounts payable	**(337)**	(340)
Long term		
Intangibles and other assets	**374**	260
Deferred amounts	**(282)**	(272)

Derivative Financial Instruments of Joint Ventures Included in the Derivative Financial Instruments Summary tables are amounts related to power derivatives used by one of the Company's joint ventures to manage commodity price risk. The Company's proportionate share of the fair value of these power sales derivatives was $48 million at December 31, 2010 (2009 – $105 million). These contracts mature from 2011 to 2015. The Company's proportionate share of the notional sales volumes of power associated with this exposure was 3,772 GWh at December 31, 2010 (2009 – 6,312 GWh). The Company's proportionate share of the notional purchased volumes of power associated with this exposure was 2,322 GWh at December 31, 2010 (2009 – 2,747 GWh).

Fair Value Hierarchy

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

There were no transfers between Level I and Level II in 2010 and 2009. Financial assets and liabilities measured at fair value, including both current and non-current portions, are categorized as follows:

	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total	
December 31 *(millions of dollars, pre-tax)*	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
Natural Gas Inventory	**–**	–	**49**	73	**–**	–	**49**	73
Derivative Financial Instrument Assets:								
Interest rate contracts	**–**	–	**28**	40	**–**	–	**28**	40
Foreign exchange contracts	**10**	10	**179**	104	**–**	–	**189**	114
Power commodity contracts	**–**	–	**269**	311	**5**	14	**274**	325
Gas commodity contracts	**93**	55	**56**	49	**–**	–	**149**	104
Oil commodity contacts	**–**	–	**–**	5	**–**	–	**–**	5
Derivative Financial Instrument Liabilities:								
Interest rate contracts	**–**	–	**(47)**	(119)	**–**	–	**(47)**	(119)
Foreign exchange contracts	**(11)**	(6)	**(54)**	(120)	**–**	–	**(65)**	(126)
Power commodity contracts	**–**	–	**(299)**	(229)	**(8)**	(16)	**(307)**	(245)
Gas commodity contracts	**(178)**	(103)	**(15)**	(27)	**–**	–	**(193)**	(130)
Oil commodity contacts	**–**	–	**–**	(5)	**–**	–	**–**	(5)
Non-Derivative Financial Instruments:								
Available-for-sale assets	**20**	23	**–**	–	**–**	–	**20**	23
	(66)	(21)	**166**	82	**(3)**	(2)	**97**	59

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

(millions of dollars, pre-tax)	Derivatives[1]
Balance at December 31, 2008	–
New contracts[2]	(14)
Transfers into Level III[3]	12
Balance at December 31, 2009	(2)
New contracts[2]	**(16)**
Settlements	**(3)**
Transfers into Level III[4]	**3**
Transfers out of Level III[4][5]	**(38)**
Change in unrealized gains recorded in Net Income	**14**
Change in unrealized gains recorded in Other Comprehensive (Loss)/Income	**39**
Balance at December 31, 2010	**(3)**

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

(2) At December 31, 2010, the total amount of net gains included in Net Income attributable to derivatives that were entered into during the year and still held at the reporting date was $1 million (2009 – nil).

(3) These contracts were previously included in Level II but were reclassified to Level III due to reduced liquidity in the market to which they relate.

(4) Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which inputs are considered to be observable.

(5) As contracts near maturity, they are transferred out of Level III and into Level II.

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in an $8 million decrease or increase, respectively, in the fair value of outstanding derivative financial instruments included in Level III as at December 31, 2010.

OTHER RISKS

Development Projects and Acquisitions

TransCanada continues to focus on growing its Natural Gas Pipelines, Oil Pipelines and Energy operations through greenfield development projects and acquisitions. TransCanada capitalizes costs incurred on certain of its projects during the development period prior to construction when the project meets specific criteria and is expected to proceed through to completion. The related capital costs of a project that does not proceed through to completion are expensed at the time it is discontinued to the extent that these costs and underlying materials cannot be utilized on another project. There is a risk with respect to TransCanada's acquisition of assets and operations that certain commercial opportunities and operational synergies may not materialize as expected and that the assets would subsequently be subject to an impairment write-down.

Asset Commissioning

Although each of TransCanada's newly-constructed assets goes through rigorous acceptance testing prior to being placed in service, there is a risk that these assets will have lower than expected availability or performance, especially in their first year of operations.

Health, Safety and Environment Risk Management

Health, safety and environment (HS&E) are top priorities in all of TransCanada's operations and activities. These areas are guided by the Company's HS&E Commitment Statement, which outlines guiding principles for a safe and healthy environment for TransCanada's employees, contractors and the public, and for TransCanada's commitment to protect the environment. All employees are responsible for the Company's HS&E performance. The Company is committed to being an industry leader in conducting its business so that it meets or exceeds all applicable laws and regulations, and minimizes risk to people and the environment. The Company is committed to tracking and improving its HS&E performance, and to promoting safety on and off the job in the belief that all occupational injuries and illnesses are preventable. TransCanada endeavours to do business with companies and contractors that share its perspective on HS&E performance and to influence them to improve their collective performance. TransCanada is committed to respecting the diverse environments and cultures in which it operates and to supporting open communication with its stakeholders.

The HS&E Committee of TransCanada's Board of Directors monitors compliance with the Company's HS&E corporate policy through regular reporting. TransCanada's HS&E management system is modeled on the International Organization for Standardization (ISO) standard for environmental management systems, ISO 14001, and focuses resources on the areas of significant risk to the organization's HS&E business activities. Management is informed regularly of all important HS&E operational issues and initiatives through formal reporting processes. TransCanada's HS&E management system and performance are assessed by an independent outside firm every three years. The most recent assessment occurred in December 2009 and did not identify any material issues. The HS&E management system is subject to ongoing internal review to ensure that it remains effective as circumstances change.

As one of TransCanada's priorities, safety is an integral part of the way its employees work. In 2010, one of the Company's objectives was to sustain health and safety performance. Overall, the Company's safety frequency rates in 2010 continued to be better than most industry benchmarks.

The safety and integrity of the Company's existing and newly-developed infrastructure also continued to be top priorities. All new assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are brought into service only after all necessary requirements have been satisfied. The Company expects to spend approximately $250 million in 2011 for pipeline integrity on its wholly owned pipelines, an increase of approximately $95 million over 2010 primarily due to increased levels of in-line pipeline inspection on all systems and pipeline enhancements in areas of population encroachment. Under the approved regulatory models in Canada, non-capital pipeline integrity expenditures on NEB-regulated pipelines are treated on a flow-through basis and, as a result, these expenditures have no impact on TransCanada's earnings. Under the Keystone contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, these expenditures have no impact on TransCanada's earnings. Expenditures for GTN may also be recovered through a cost-recovery mechanism in its rates if threshold expenditures are achieved. TransCanada's pipeline safety record in 2010 continued to be above industry benchmarks. TransCanada experienced no pipeline breaks in 2010. Spending associated with public safety on the Energy assets is focused primarily on the Company's hydro dams and associated equipment, and is consistent with previous years.

Environment

TransCanada's facilities are subject to stringent federal, provincial, state and local environmental statutes and regulations, including requirements that establish compliance and remedial obligations. Such laws and regulations generally require facilities to obtain or comply with a wide variety of environmental restrictions, licences, permits and other approvals. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, the imposition of remedial requirements or the issuance of orders respecting future operations. TransCanada has ongoing inspection programs designed to keep all of its facilities in compliance with environmental requirements.

As mentioned above, TransCanada's operations are subject to various environmental laws and regulations that establish compliance and remediation obligations. Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any failure to comply, and potential limitations on operations. Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated properties, and with damage claims arising from the contamination of properties. It is not possible for the Company to estimate the amount and timing of all future expenditures related to environmental matters due to:

- uncertainties in estimating pollution control and clean up costs, including at sites where only preliminary site investigation or agreements have been completed;
- the potential discovery of new sites or additional information at existing sites;
- the uncertainty in quantifying the Company's liability under environmental laws that impose joint and several liability on all potentially responsible parties;
- the evolving nature of environmental laws and regulations, including the interpretation and enforcement of them; and
- the potential for litigation on existing or discontinued assets.

Environmental risks from TransCanada's operating facilities typically include: air emissions, such as nitrogen oxides, particulate matter and greenhouse gases (GHG); potential impacts on land, including land reclamation or restoration following construction; the use, storage and release of chemicals or hydrocarbons; the generation, handling and disposal of wastes and hazardous wastes; and water impacts such as uncontrolled water discharge. Environmental controls including physical design, programs, procedures and processes are in place to effectively manage these risks.

At December 31, 2010, TransCanada recorded liabilities of approximately $84 million (2009 – $91 million) for remediation obligations and compliance costs associated with environmental regulations. The Company believes it has considered all necessary contingencies and established appropriate reserves for environmental liabilities, however, there is the risk that unforeseen matters may arise requiring the Company to set aside additional amounts.

TransCanada is not aware of any material outstanding orders, claims or lawsuits against it in relation to the release or discharge of any material into the environment or in connection with environmental protection.

Regulation of air pollutant emissions under the U.S. *Clean Air Act* and state regulations continue to evolve. A number of EPA initiatives could lead to impacts ranging from requirements to install emissions control equipment, to additional administrative and reporting requirements. At this time, there is insufficient detail to accurately determine the potential impacts of these initiatives. While the majority of the proposals are not expected to be material to TransCanada, the Company anticipates additional future costs related to the monitoring and control of air emissions.

In addition to those climate change policies already in place, there are also several federal, Canada and U.S., regional and provincial initiatives currently in development. While recent political and economic events may significantly affect the scope and timing of new policies, TransCanada anticipates that most of the Company's facilities in Canada and the U.S. are or will be subject to federal or regional climate change regulations to manage industrial GHG emissions. Certain of these initiatives are outlined below.

In 2010, the Company owned assets in four regions, Alberta, Québec, B.C., and northeastern U.S., where regulations exist to address industrial GHG emissions. TransCanada has procedures in place to address these regulations.

In Alberta, under the *Specified Gas Emitters Regulation*, industrial facilities emitting GHGs over an intensity threshold level are required to reduce GHG emissions intensities by 12 per cent below an average baseline. TransCanada's Alberta-based facilities are subject to this regulation, as are the Sundance and Sheerness coal-fired power facilities with which TransCanada has PPAs. As an alternative to reducing emissions intensities, compliance can be achieved through acquiring offsets or making payments to a technology fund at a cost of $15 per tonne of carbon dioxide (CO_2) equivalents in excess of the mandated reduction. A program is in place to manage the compliance costs incurred by these assets as a result of regulation. Compliance costs on the Alberta System are recovered through rates paid by customers. Some of the compliance costs from the Company's power generation facilities in Alberta are recovered through market pricing and contract flow-through provisions. TransCanada has estimated and recorded related costs of $22 million for 2010, after contracted cost recovery.

In Québec, the natural gas distributor collects the hydrocarbon royalty on behalf of the provincial government through a green fund contribution charge on gas consumed. In 2010, the cost pertaining to the Bécancour facility arising from the hydrocarbon royalty was less than $1 million as a result of an agreement between TransCanada and Hydro-Québec to temporarily suspend the facility's power generation. The cost is expected to increase substantially when the plant returns to service.

The carbon tax in B.C., which came into effect in mid 2008, applies to CO_2 emissions from fossil fuel combustion. Compliance costs for fuel combustion at the Company's compressor and meter stations in B.C. are recovered through tolls paid by customers. Costs related to the carbon tax in 2010 were estimated to be $4 million. As specified by this law, the cost per tonne of CO_2 will increase in July 2011 to $25 from $20.

Northeastern U.S. states that are members of the Regional Greenhouse Gas Initiative (RGGI) implemented a CO_2 cap-and-trade program for electricity generators effective in January 2009. Under the RGGI, both the Ravenswood and OSP generation facilities will be required to submit allowances following the end of the first compliance period on December 31, 2011. TransCanada participated in the quarterly auctions of allowances for the Ravenswood and OSP generation facilities and incurred related costs of approximately $5 million in 2010. These costs were generally recovered through the power market and the net impact on TransCanada was not significant.

The Canadian government has continued to express interest in pursuing a harmonized continental climate change strategy. In January 2010, Environment Canada submitted a revised GHG reduction target to the United Nations Framework Convention on Climate Change as part of its submission for the *Copenhagen Accord*. The revised target represents a 17 per cent reduction in GHG emissions by 2020 relative to 2005 levels. In June 2010, the Federal government initiated consultation on its policy for coal-fired power operations with the stated intention of publishing the draft regulatory framework in *Canada Gazette* in early 2011. TransCanada participated in this consultation process directly through meetings with government officials and the Canadian Electricity Association. The new regulations to reduce GHG emissions for coal-fired operations are expected to come into effect July 2015.

In the U.S., the EPA is proceeding towards regulating industrial GHG emissions under the *Clean Air Act*. In May 2010, the EPA issued its final version of the Tailoring Rule, which outlines emissions thresholds and a schedule for phasing in certain permitting requirements under the *Clean Air Act*. Under this rule, the Prevention of Significant Deterioration (PSD) program stipulates the air pollution protection criteria a company must meet to obtain a construction permit. Requirements will apply to GHG emissions starting in January 2011. The second phase of the program will commence in July 2011, with new rulemaking in 2012 to establish emission thresholds and permitting requirements to take effect in 2013. In addition to the PSD requirements, the Tailoring Rule sets comparable emissions thresholds and timetables for new and existing facilities to obtain operating permits under Title V of the *Clean Air Act*. The regulation of GHG emissions by the EPA under the *Clean Air Act* would have implications for TransCanada with respect to permitting for existing, new and modified facilities.

The Western Climate Initiative (WCI) continues to work toward implementing a regional cap-and-trade program expected to come into effect in 2012. The cap-and-trade program would be a key component of the plan to help WCI members reach their goal of reducing GHG emissions 15 per cent below 2005 levels by 2020. Beginning in 2012, the cap would cover utilities and large industrial sectors, and expand by 2015 to cover transportation fuels, and commercial and residential fuels. The WCI comprises seven western U.S. states and four Canadian provinces. While TransCanada has assets located in all four Canadian member provinces (B.C., Manitoba, Ontario and Québec) and five of the member states (California, Oregon, Washington, Montana and Arizona), the cap-and-trade program is proposed to begin in 2012 in California and the Canadian provinces of B.C., Québec and Ontario. The programs would cover TransCanada's pipeline and power facilities, however, TransCanada expects the cost of compliance would be largely recoverable on the facilities that trigger emissions thresholds.

In April 2010, the EPA published an "Advanced Notice of Proposed Rulemaking" to solicit comments with respect to the EPA's reassessment of current regulations under the *Toxic Substances Control Act*, governing the authorized use of polychlorinated biphenyls (PCB) in certain equipment. The proposed changes could require notification to the EPA when PCBs are discovered in any pipeline system, a phase out and eventual elimination of PCB use in pipeline systems and air compressor systems, and the immediate elimination of the storage of PCB equipment for reuse. If finalized as proposed, these changes are likely to have significant cost implications for the Company's U.S. assets.

TransCanada monitors climate change policy developments and, when warranted, participates in policy discussions in jurisdictions where the Company has operations. The Company is also continuing its programs to manage GHG emissions from its facilities and to evaluate new processes and technologies that result in improved efficiencies and lower GHG emission rates.

In 2010, the Keystone Wood River/Patoka phase became operational. Steel pipelines are a safe, efficient and economical method of transporting crude oil. The equipment and procedures put in place with respect to Keystone provide the capability to contain oil leaks quickly and safely.

TransCanada's pipelines are designed, constructed and operated to the highest industry standards and meet or exceed all regulatory requirements. Keystone is continuously monitored and is fully automated with remotely-started secure pumps and valves. A variety of methods are used to detect and prevent leaks. In the unlikely event of a leak or spill, valves can be closed to isolate the leak and limit spill volumes.

The Company has established emergency response plans to be enacted in the unlikely event of a leak or spill along TransCanada's operational crude oil pipeline. The plans encompass the necessary personnel and equipment to respond to any size of spill as well as clean-up and remediation operations to minimize any effects on the environment. The plans outline specific environmental features in the vicinity of the pipeline and containment and remediation efforts are based on practices that are well-understood and tested. In addition, TransCanada has an on-going program to provide local emergency responders with the information and training necessary to ensure their preparedness for responding to events.

The impact of new or proposed provincial, state or federal safety and environmental laws, regulations, guidelines and enforcement in Canada and the U.S. on TransCanada's business is not yet certain. TransCanada makes assumptions about possible expenditures to safety and environmental matters based on current laws and regulations and interpretations thereof. If the laws or regulations or the interpretation thereof changes, the Company's assumptions may change. Incremental costs may or may not be recoverable under existing rate structures or commercial agreements. Proposed changes in environmental policy, legislation or regulation are routinely monitored by TransCanada and where the risks are potentially large or uncertain the Company works independently or through industry associations to comment on proposals.

Future Abandonment Costs

Dependent on specific operating jurisdictions, the Company may have obligations to abandon its facilities in accordance with applicable laws and regulations.

To the extent legal obligations exist and can be reasonably estimated, the Company records Asset Retirement Obligations based on estimated fair value, which are accreted at the end of each period. The Company recorded Asset Retirement Obligations associated with the retirement of certain power generation facilities, natural gas pipelines and transportation facilities, and natural gas storage systems. The estimates or assumptions required to calculate Asset Retirement Obligations include scope of abandonment and reclamation activities, inflation rates, discount rates and timing of retirement assets. By their nature, these assumptions are subject to measurement uncertainty. The Company has determined that the scope and timing of asset retirement related to its regulated natural gas pipelines, oil pipelines and hydroelectric power plants are so uncertain that a reasonable estimate cannot be made. As a result, the Company has not recorded amounts for Asset Retirement Obligations related to these assets, with the exception of certain abandoned facilities.

The NEB's Land Matters Consultation Initiative deals with pipeline abandonment, including related financial issues. The goal of this initiative is for all pipeline companies regulated under the *National Energy Board Act* (Canada) to begin collecting and setting aside funds to cover future abandonment costs by mid-2014. In its May 2009 decision, the NEB established several filing deadlines relating to the financial issues, including deadlines for preparing and filing an estimate of the abandonment costs to be used to begin collecting funds, developing a proposal for collecting these funds through tolls or some other satisfactory method and developing a proposed process to set aside the funds collected. TransCanada is preparing to file its estimates of abandonment costs for its Canadian oil and natural gas pipelines by May 31, 2011, as required by the NEB decision. These costs would be recovered from shippers through tolls in accordance with the NEB's determination that abandonment costs are a legitimate cost of providing service and are recoverable upon NEB approval from users of the system. The specific toll impacts have not yet been determined as they will be the subject of a subsequent NEB filing in late 2012.

For the foreseeable future, the Company intends to operate and maintain these assets as long as supply and demand exists for hydroelectric power generation, natural gas and oil. The Company continues to evaluate its obligations related to future abandonment costs and to monitor developments that could impact the amounts it records.

CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As at December 31, 2010, an evaluation of the effectiveness of TransCanada's disclosure controls and procedures as defined under the rules adopted by the Canadian securities regulatory authorities and by the SEC was carried out under the supervision and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer. Based on this evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that, as at December 31, 2010, the design and operation of TransCanada's disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by the Company in reports filed with, or submitted to, securities regulatory authorities is accumulated and communicated to management, including the President and Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure and were effective to provide reasonable assurance that such information is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws.

Management's Annual Report on Internal Control over Financial Reporting

Internal control over financial reporting is a process designed by or under the supervision of senior management and effected by the Board of Directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and preparation of consolidated financial statements for external purposes in accordance with Canadian GAAP, including a reconciliation to U.S. GAAP.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting, no matter how well designed, has inherent limitations and can only provide reasonable assurance with respect to the preparation and fair presentation of published financial statements. Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on this evaluation, management concluded that internal control over financial reporting was effective as at December 31, 2010, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

In 2010, there was no change in TransCanada's internal control over financial reporting that materially affected or is reasonably likely to materially affect TransCanada's internal control over financial reporting.

CEO and CFO Certifications

TransCanada's President and Chief Executive Officer and Chief Financial Officer have filed with the SEC and the Canadian securities regulators certifications regarding the quality of TransCanada's public disclosures relating to its fiscal 2010 reports filed with the SEC and the Canadian securities regulators.

SIGNIFICANT ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

To prepare financial statements that conform with GAAP, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses, since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions. TransCanada regularly assesses the assets and liabilities associated with these estimates and assumptions, and believes that no material adjustments are required. The Company believes the following accounting policies and estimates require it to make assumptions about highly uncertain matters and changes in these estimates could have a material impact on the Company's financial information.

Rate-Regulated Accounting

The Company accounts for the impacts of rate regulation in accordance with GAAP. The following three criteria must be met to use these accounting principles:

- the rates for regulated services or activities must be established by or subject to approval by a regulator;
- the regulated rates must be designed to recover the cost of providing the services or products; and
- it must be reasonable to assume that rates set at levels to recover the cost can be charged to and collected from customers in view of the demand for services or products and the level of direct and indirect competition.

The Company's management believes all three of these criteria have been met with respect to each of the regulated natural gas pipelines accounted for using rate-regulated accounting principles. The most significant impact from the use of these accounting principles is that the timing of recognition of certain Natural Gas Pipelines expenses and revenues in the regulated businesses may differ from that otherwise expected under GAAP in order to appropriately reflect the economic impact of the regulators' decisions regarding the Company's revenues and tolls. At December 31, 2010, the Company reported regulatory assets of $1.5 billion and $0.3 billion in Regulatory Assets and Other Current Assets, respectively (2009 – $1.5 billion and $0.2 billion, respectively), and regulatory liabilities of $0.3 billion and $0.1 billion in Regulatory Liabilities and Accounts Payable, respectively (2009 – $0.4 billion and $31 million, respectively).

Financial Instruments and Hedges

Financial Instruments

The Company initially records all financial instruments on the Balance Sheet at their fair value. Subsequent measurement of the financial instruments is based on their classification as held for trading, available for sale, held-to-maturity investments, loans and receivables, and other financial liabilities. Changes in the fair value of financial instruments are recorded in Net Income except those for available-for-sale assets, whose fair value adjustments are recorded in Other Comprehensive (Loss)/Income.

Held-for-trading derivative financial assets and liabilities consist of swaps, options, forwards and futures. The available-for-sale classification includes non-derivative financial assets that are designated as available for sale or are not included in the other three classifications. Trade receivables and loans and other receivables with fixed or determinable payments that are not quoted in an active market are classified as Loans and Receivables and are measured at amortized cost using the effective interest method, net of any impairment. The Company does not have any held-to-maturity investments. Other financial liabilities consist of liabilities not classified as held for trading and are recognized at amortized cost using the effective interest method.

Hedges

The Company applies hedge accounting to its arrangements that qualify for hedge accounting treatment, which include fair value and cash flow hedges, and to hedges of foreign currency exposures of net investments in self-sustaining foreign operations. Hedge accounting is discontinued prospectively when the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item. Changes in fair value of the hedged and hedging items are recognized in Net Income.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in Other Comprehensive (Loss)/Income, while any ineffective portion is recognized in Net Income in the same financial category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in Accumulated Other Comprehensive (Loss)/Income (AOCI) are reclassified to Net Income during the periods when the variability in cash flows of the hedged item affects Net Income. Gains and losses on derivatives are reclassified immediately to Net Income from AOCI when the hedged item is sold or terminated early, or when a hedged anticipated transaction is no longer expected to occur.

The Company also enters into cash flow hedges and fair value hedges for activities subject to rate regulation. Any gains and losses arising from changes in the fair value of these hedges can be recovered through the tolls charged by the Company. As a result, any gains and losses are deferred as Regulatory Assets or Regulatory Liabilities on behalf of the ratepayers. When the hedges are settled, the realized gains and losses are refunded to or collected from the ratepayers in subsequent years.

In hedging the foreign currency exposure of a net investment in a self-sustaining foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in Other Comprehensive (Loss)/Income and the ineffective portion is recognized in Net Income. The amounts recognized previously in AOCI are reclassified to Net Income in the event the Company reduces its investment in a foreign operation.

The fair value of financial instruments and hedges, where fair value does not approximate carrying value, is primarily derived from market values adjusted for credit risk, which can fluctuate widely from period to period. Since the changes in fair value are recorded through earnings, fluctuations can result in variability in Net Income.

Financial instruments and hedges, including risks associated with fluctuations to earnings and cash flows, are discussed further in the Risk Management and Financial Instruments section in this MD&A.

Depreciation and Amortization Expense

TransCanada's Plant, Property and Equipment are depreciated on a straight-line basis over their estimated useful lives once they are ready for their intended use. The estimation of useful lives requires management's judgement regarding the period of time the assets will be in use based on third-party engineering studies, experience and industry practice. The initial payment for the Company's PPAs is deferred and amortized on a straight-line basis over the terms of the contracts, which expire in 2017 and 2020.

Natural gas pipeline and compression equipment is depreciated at annual rates ranging from one per cent to six per cent. Oil pipeline and pumping equipment is depreciated at annual rates ranging from approximately two per cent to 2.5 per cent. Metering and other plant equipment are depreciated at various rates. Major power generation and natural gas storage plant, equipment and structures in the Energy business are depreciated by major component on a straight-line basis over estimated service lives at average annual rates ranging from two per cent to 20 per cent. Nuclear power generation assets under capital lease are recorded initially at the present value of minimum lease payments at the inception of the lease and amortized on a straight-line basis over the shorter of their useful life and the remaining lease term. Other Energy equipment is depreciated at various rates. Corporate Plant, Property and Equipment are depreciated on a straight-line basis over estimated useful lives at average annual rates ranging from three per cent to 20 per cent.

Depreciation and Amortization expense in 2010 was $1,354 million (2009 – $1,377 million; 2008 – $1,247 million) and was recorded in Natural Gas Pipelines and Energy. In Natural Gas Pipelines, depreciation rates are approved by regulators when applicable and depreciation expense is recoverable based on the cost of providing the services or products. If regulators permit recovery of depreciation through rates charged to customers, a change in the estimate of the useful lives of plant, property and equipment in the Natural Gas Pipelines segment will have no material impact on TransCanada's Net Income but will directly affect Funds Generated from Operations. PPA amortization expense of $58 million was included in Energy's Depreciation and Amortization expense for each year from 2008 through 2010.

Impairment of Long-Lived Assets and Goodwill

The Company reviews long-lived assets such as plant, property and equipment, as well as intangible assets for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets.

At December 31, 2010, the Company reported Goodwill of $3.6 billion (2009 – $3.8 billion). Goodwill is tested in the Natural Gas Pipelines and Energy segments for impairment annually or more frequently if events or changes in circumstances indicate that the asset might be impaired. An initial test is done by comparing the fair value of the operations, which includes goodwill, to the book value of each reporting unit. If the fair value is less than book value, an impairment is indicated and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of the goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of goodwill exceeds the calculated implied fair value of the goodwill, an impairment charge is recorded.

These valuations are based on management's projections of future cash flows and, therefore, require estimates and assumptions with respect to:

- discount rates;
- commodity and capacity prices;
- market supply and demand assumptions;
- growth opportunities;
- output levels;
- competition from other companies; and
- regulatory changes.

Significant changes in these assumptions could affect the Company's need to record an impairment charge.

ACCOUNTING CHANGES

FUTURE ACCOUNTING CHANGES

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

The Canadian Institute of Chartered Accountants (CICA) Handbook Section 1582 "Business Combinations" is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting the standard is expected to have a material effect on the way the Company accounts for future business combinations. Entities adopting Section 1582 will also be required to adopt CICA Handbook Sections 1601

"Consolidated Financial Statements" and 1602 "Non-Controlling Interests". Sections 1601 and 1602 will require Non-Controlling Interests to be presented as part of Shareholders' Equity on the Balance Sheet. In addition, the income statement of the controlling parent will include 100 per cent of the subsidiary's results and present the allocation of income between the controlling and non-controlling interests. These standards will be effective January 1, 2011. Changes resulting from the adoption of Section 1582 will be applied prospectively and changes resulting from the adoption of Sections 1601 and 1602 will be applied retrospectively.

International Financial Reporting Standards

The CICA's Accounting Standards Board (AcSB) previously announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. As an SEC registrant, TransCanada prepares and files a "Reconciliation to United States GAAP" and has the option to prepare and file its consolidated financial statements using U.S. GAAP. Previously, TransCanada disclosed that effective January 1, 2011, the Company expected to begin reporting under IFRS. As a result of the developments noted below, management expects that the Company will adopt U.S. GAAP effective January 1, 2012. The Company's IFRS conversion project was proceeding as planned to meet the conversion date of January 1, 2011, prior to these developments.

In accordance with GAAP, TransCanada follows specific accounting policies unique to a rate-regulated business. These RRA standards allow the timing of recognition of certain expenses and revenues to differ from the timing that may otherwise be expected in a non-rate-regulated business under GAAP in order to appropriately reflect the economic impact of regulators' decisions regarding the Company's revenues and tolls. These timing differences are recorded as Regulatory Assets and Regulatory Liabilities on TransCanada's Consolidated Balance Sheet and represent current rights and obligations regarding cash flows expected to be recovered from or refunded to customers based on decisions and approvals by the applicable regulatory authorities. At December 31, 2010, TransCanada reported regulatory assets of $1.8 billion and regulatory liabilities of $0.4 billion in addition to certain other impacts of RRA.

In July 2009, the IASB issued an Exposure Draft "Rate-Regulated Activities", which proposed a form of RRA under IFRS. At its September 2010 meeting, the IASB concluded that the development of RRA under IFRS requires further analysis and removed the RRA project from its current agenda. The IASB is considering what form a future project might take, if any, to address RRA. TransCanada does not expect a final RRA standard under IFRS to be effective for 2012.

In October 2010, the AcSB and the Canadian Securities Administrators amended their policies applicable to Canadian publicly accountable enterprises that use RRA in order to permit these entities to defer the adoption of IFRS for one year. Due to the continued uncertainty around the timing, scope and eventual adoption of an RRA standard under IFRS, TransCanada will defer its adoption of IFRS accordingly and continue preparing its consolidated financial statements in 2011 in accordance with Canadian GAAP, as defined by Part V of the CICA Handbook, in order to continue using RRA. TransCanada will continue to actively monitor IASB developments with respect to RRA and other IFRS.

U.S. GAAP Conversion Project

The impact of adopting U.S. GAAP is consistent with that currently reported in the Company's publicly filed "Reconciliation to United States GAAP". Significant changes to existing systems and processes are not required to implement U.S. GAAP as the Company's primary accounting standard.

TransCanada's IFRS conversion team has been redeployed to support the conversion to U.S. GAAP. All staff affected by the conversion will be provided with in-depth U.S. GAAP training and technical research will be conducted. The conversion team is led by a multi-disciplinary Steering Committee that provides directional leadership for the likely adoption of U.S. GAAP. Management also updates TransCanada's Audit Committee on the progress of this project and on any pertinent developments related to IFRS at each Audit Committee meeting.

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA[1]

(unaudited) (millions of dollars except per share amounts)	2010 Fourth	 Third	 Second	 First
Revenues	**2,057**	**2,129**	**1,923**	**1,955**
Net Income	**283**	**391**	**295**	**303**
Share Statistics				
Net income per share – basic and diluted	**$0.39**	**$0.54**	**$0.41**	**$0.43**
Dividend declared per common share	**$0.40**	**$0.40**	**$0.40**	**$0.40**

(unaudited) (millions of dollars except per share amounts)	2009 Fourth	 Third	 Second	 First
Revenues	1,986	2,049	1,984	2,162
Net Income	387	345	314	334
Share Statistics				
Net income per share – basic and diluted	$0.56	$0.50	$0.50	$0.54
Dividend declared per common share	$0.38	$0.38	$0.38	$0.38

[1] The selected quarterly consolidated financial data has been prepared in accordance with GAAP.

Factors Affecting Quarterly Financial Information

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

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

Significant developments that affected EBIT and Net Income in 2010 and 2009 were as follows:

- ***Fourth Quarter 2010*** Natural Gas Pipelines' EBIT decreased as a result of recording a $146 million pre-tax ($127 million after-tax) valuation provision for advances to the APG for the MGP. Energy's EBIT included contributions from the second phase of Kibby Wind, which was placed in service in October 2010, and net unrealized gains of

$22 million pre-tax ($12 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

- ***Third Quarter 2010*** Natural Gas Pipelines' EBIT increased as a result of recording nine months of incremental earnings related to the Alberta System 2010 - 2012 Revenue Requirement Settlement, which resulted in a $33 million increase to Net Income. Energy's EBIT included contributions from Halton Hills, which was placed in service in September 2010, and net unrealized gains of $4 million pre-tax ($3 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.
- ***Second Quarter 2010*** Energy's EBIT included net unrealized gains of $15 million pre-tax ($10 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. Net Income reflected a decrease of $58 million after tax due to losses in 2010 compared to gains in 2009 for interest rate and foreign exchange rate derivatives that did not qualify as hedges for accounting purposes and the translation of U.S. dollar-denominated working capital balances.
- ***First Quarter 2010*** Energy's EBIT included net unrealized losses of $49 million pre-tax ($32 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.
- ***Fourth Quarter 2009*** Natural Gas Pipelines EBIT included a dilution gain of $29 million pre-tax ($18 million after tax) resulting from TransCanada's reduced ownership interest in PipeLines LP, which was caused by PipeLines LP's issue of common units to the public. Energy's EBIT included net unrealized gains of $7 million pre-tax ($5 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. Net Income included $30 million of favourable income tax adjustments resulting from reductions in the Province of Ontario's corporate income tax rates.
- ***Third Quarter 2009*** Energy's EBIT included net unrealized gains of $14 million pre-tax ($10 million after tax) due to changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.
- ***Second Quarter 2009*** Energy's EBIT included net unrealized losses of $7 million pre-tax ($5 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. 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) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

FOURTH QUARTER 2010 HIGHLIGHTS

Reconciliation of Comparable Earnings, Comparable EBITDA, Comparable EBIT and EBIT to Net Income Applicable to Common Shares

Three months ended December 31 *(unaudited)(millions of dollars except per share amounts)*	Natural Gas Pipelines		Energy		Corporate		Total	
	2010	2009	**2010**	2009	**2010**	2009	**2010**	2009
Comparable EBITDA[1]	**737**	745	**301**	248	**(33)**	(28)	**1,005**	965
Depreciation and amortization	**(241)**	(257)	**(103)**	(86)	**–**	–	**(344)**	(343)
Comparable EBIT[1]	**496**	488	**198**	162	**(33)**	(28)	**661**	622
Specific items:								
Valuation provision for MGP	**(146)**	–	**–**	–	**–**	–	**(146)**	–
Risk management activities	**–**	–	**22**	7	**–**	–	**22**	7
Dilution gain from reduced interest in PipeLines LP	**–**	29	**–**	–	**–**	–	**–**	29
EBIT[1]	**350**	517	**220**	169	**(33)**	(28)	**537**	658
Interest expense							**(173)**	(184)
Interest expense of joint ventures							**(15)**	(17)
Interest income and other							**61**	22
Income taxes							**(94)**	(67)
Non-controlling interests							**(33)**	(25)
Net Income							**283**	387
Preferred share dividends							**(14)**	(6)
Net Income Applicable to Common Shares							**269**	381
Specific items (net of tax where applicable):								
Valuation provision for MGP							**127**	–
Risk management activities							**(12)**	(5)
Dilution gain from reduced interest in PipeLines LP							**–**	(18)
Income tax adjustments							**–**	(30)
Comparable Earnings[1]							**384**	328
Net Income per Share – Basic and Diluted[2]							**$0.39**	$0.56

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

(2) For the three months ended December 31

(unaudited)	**2010**	2009
Comparable Earnings per Share[1]	**$0.55**	$0.48
Specific items (net of tax where applicable):		
Valuation provision for MGP	**(0.18)**	–
Risk management activities	**0.02**	0.01
Dilution gain from reduced interest in PipeLines LP	**–**	0.03
Income tax adjustments	**–**	0.04
Net Income per Share	**$0.39**	$0.56

TransCanada's Net Income in fourth quarter 2010 was $283 million and Net Income Applicable to Common Shares was $269 million or $0.39 per share compared to $387 million and $381 million or $0.56 per share, respectively, in fourth quarter 2009.

Comparable Earnings in fourth quarter 2010 were $384 million or $0.55 per share, compared to $328 million or $0.48 per share for the same period in 2009. Comparable Earnings in fourth quarter 2010 excluded the $127 million after-tax ($146 million pre-tax) valuation provision for advances to the APG for the MGP. Comparable Earnings in fourth quarter 2010 also excluded net unrealized gains of $12 million after tax ($22 million pre-tax) (2009 – gains of $5 million after tax ($7 million pre-tax)) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. Comparable Earnings in fourth quarter 2009 also excluded the $30 million of favourable income tax adjustments arising from a reduction in the Province of Ontario's corporate income tax rates and the $18 million after-tax ($29 million pre-tax) dilution gain resulting from TransCanada's reduced ownership interest in PipeLines LP, after a public offering of PipeLines LP common units in fourth quarter 2009. The $56 million increase in Comparable Earnings reflected:

- increased Comparable EBIT from Natural Gas Pipelines primarily due to lower business development costs and higher earnings from the Alberta System revenue requirement settlement, increased revenues from Northern Border and reduced depreciation expense for Great Lakes, partially offset by lower revenues from the Canadian Mainline and Alberta System for amounts that are recovered on a flow-through basis;
- increased Comparable EBIT from Energy primarily due to increased power generation at Bruce A, higher capacity revenues, sales volumes and realized prices for U.S. Power, and incremental earnings from the start-up of Halton Hills, which went into service in September 2010, partially offset by lower Bruce B lease expense in 2009, lower realized power prices for Western Power and Bruce B, and decreased proprietary and third-party storage revenues for Natural Gas Storage;
- increased Comparable EBIT loss from Corporate primarily due to higher support services and other corporate costs;
- decreased Interest Expense primarily due to increased capitalized interest, relating to Keystone and other capital projects, and the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest expense, partially offset by incremental interest expense on new debt issues in 2010;
- increased Interest Income and Other, reflecting higher gains in fourth quarter 2010 compared to fourth quarter 2009 from changes in the fair value of derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income;
- increased Income Taxes in fourth quarter 2010 compared to fourth quarter 2009 due to positive income tax adjustments that reduced income taxes in fourth quarter 2009, partially offset by lower pre-tax earnings in fourth quarter 2010; and
- increased preferred share dividends recorded for preferred shares issued in 2010.

Natural Gas Pipelines' Comparable EBIT was $496 million in fourth quarter 2010 compared to $488 million in the same period in 2009. Comparable EBIT in fourth quarter 2010 excluded the $146 million pre-tax valuation provision for advances to the APG for the MGP. Comparable EBIT in 2009 excluded the $29 million pre-tax dilution gain resulting from TransCanada's reduced ownership interest in PipeLines LP, which occurred following public issuance of common units by PipeLines LP in fourth quarter 2009.

Canadian Mainline's net income in fourth quarter 2010 decreased $1 million to $71 million from $72 million for the same period in 2009. Net income in fourth quarter 2010 reflected a lower ROE of 8.52 per cent compared to 8.57 per cent in 2009 on a lower average investment base, partially offset by higher incentive earnings.

Canadian Mainline's Comparable EBITDA in fourth quarter 2010 of $269 million decreased $13 million from $282 million for 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 affect net income. The decrease in financial charges was primarily due to higher-cost debt that matured in 2009 and early 2010.

The Alberta System's net income of $53 million in fourth quarter 2010 increased $8 million compared to the same period in 2009. Net income in fourth quarter 2010 reflected an ROE of 9.70 per cent on 40 per cent deemed common equity and a higher average investment base, earned under the Alberta System's 2010 - 2012 Revenue Requirement Settlement, partially offset by lower incentive earnings.

The Alberta System's Comparable EBITDA was $194 million in fourth quarter 2010 compared to $193 million for the same period in 2009. Comparable EBITDA in fourth quarter 2010 reflected the ROE earned under the Alberta System's 2010 - 2012 Revenue Requirement Settlement and an increased average investment base, partially offset by lower revenues as a result of lower financial charges, which are recovered on a flow-through basis, and lower incentive earnings compared to 2009.

Net income and Comparable EBITDA from Foothills in fourth quarter 2010 of $7 million and $33 million, respectively, increased $2 million and $1 million, respectively, compared to fourth quarter 2009. The increase was primarily due to a Foothills 2010 settlement agreement that established an ROE of 9.70 per cent on deemed common equity of 40 per cent for the years 2010 to 2012. Results in 2009 were based on the NEB ROE formula of 8.57 per cent on a deemed common equity of 36 per cent.

Comparable EBITDA from Other Canadian Natural Gas Pipelines was $11 million in fourth quarter 2010 compared to $15 million for the same period in 2009. The decrease in fourth quarter 2010 was primarily due to an adjustment to TQM's cost of capital in 2009.

ANR's Comparable EBITDA in fourth quarter 2010 was US$76 million compared to US$79 million for the same period in 2009. The decrease was primarily due to lower transportation sales and storage revenues as higher regional storage inventories and marginal supply from the U.S. Gulf Coast negatively affected transportation rates and demand for natural gas.

GTN's Comparable EBITDA in fourth quarter 2010 was US$45 million compared to US$41 million for the same period in 2009. The increase was primarily due to incremental proceeds accrued in 2010 relating to the Calpine bankruptcy distributions and lower OM&A costs, partially offset by the write-off of costs related to an unsuccessful information systems project in 2010.

Comparable EBITDA for the remainder of the U.S. Natural Gas Pipelines in fourth quarter 2010 was US$128 million compared to US$126 million for the same period in 2009. The increase was primarily due to the positive impact Northern Border's higher revenues had on PipeLines LP's earnings, partially offset by lower revenues from Great Lakes. U.S. Natural Gas Pipelines was also negatively affected by higher general, administrative and support costs primarily related to the start-up of Keystone.

Natural Gas Pipelines' Business Development Comparable EBITDA losses decreased $15 million to $21 million in fourth quarter 2010 from $36 million for the same period in 2009 primarily due to decreased business development costs related to the Alaska Pipeline Project.

Energy's Comparable EBIT was $198 million in fourth quarter 2010 compared to $162 million in the same period in 2009. Comparable EBIT in fourth quarter 2010 excluded net unrealized pre-tax gains of $22 million (2009 - gains of $7 million) from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

Western Power's Comparable EBITDA of $48 million in fourth quarter 2010 decreased $13 million compared to the same period in 2009, primarily due to lower overall realized power prices. Contracted prices in fourth quarter 2010 contributed positive margins compared to margins realized under spot prices, however, contracted prices were lower than in fourth quarter 2009 due to the continued impact of the North American economic downturn.

Eastern Power's Comparable EBITDA of $77 million in fourth quarter 2010 increased $21 million compared to the same period in 2009 primarily due to incremental earnings from Halton Hills, which went into service in September 2010.

TransCanada's proportionate share of Bruce Power's Comparable EBITDA increased $29 million to $99 million in fourth quarter 2010 from $70 million in fourth quarter 2009.

TransCanada's proportionate share of Bruce A's Comparable EBITDA increased $62 million to $33 million in fourth quarter 2010 from losses of $29 million in fourth quarter 2009 as a result of higher volumes and lower operating expenses due to decreased outage days.

TransCanada's proportionate share of Bruce B's Comparable EBITDA decreased $33 million to $66 million in fourth quarter 2010 from $99 million in fourth quarter 2009 primarily due to higher lease expenses and lower realized prices resulting from the expiry of fixed-price contracts at higher prices.

U.S. Power's Comparable EBITDA in fourth quarter 2010 of US$59 million increased US$31 million compared to the same period in 2009 primarily due to higher capacity revenues, increased realized prices and higher volumes of power sold.

Natural Gas Storage's Comparable EBITDA in fourth quarter 2010 was $37 million compared to $49 million for the same period in 2009. The decrease in Comparable EBITDA in fourth quarter 2010 was primarily due to lower proprietary natural gas and third-party storage revenues as a result of reduced realized natural gas price spreads.

Interest Expense in fourth quarter 2010 decreased $11 million to $173 million from $184 million in fourth quarter 2009. The decrease reflected increased capitalized interest relating to the Company's capital growth program in 2010, primarily due to Keystone construction, the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest and Canadian dollar-denominated debt maturities in 2009 and 2010. These decreases were partially offset by incremental interest expense on new debt issues of US$1.25 billion in June 2010 and US$1.0 billion in September 2010.

Interest Income and Other in fourth quarter 2010 increased $39 million to $61 million from $22 million in fourth quarter 2009. The increase reflected higher gains in 2010 compared to 2009 from changes in the fair value of derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Income Taxes were $94 million in fourth quarter 2010 compared to $67 million for the same period in 2009. The increase was primarily due to positive income tax adjustments that reduced income taxes in 2009, including $30 million of favourable adjustments arising from a reduction in the Province of Ontario's corporate income tax rates, partially offset by lower pre-tax earnings in 2010.

SHARE INFORMATION

At February 10, 2011, TransCanada had 699 million issued and outstanding common shares, and had 22 million Series 1, 14 million Series 3 and 14 million Series 5 issued and outstanding first preferred shares that are convertible to 22 million Series 2, 14 million Series 4 and 14 million Series 6 preferred shares, respectively. In addition, there were eight million outstanding options to purchase common shares, of which six million were exercisable as at February 10, 2011.

OTHER INFORMATION

Additional information relating to TransCanada, including the Company's Annual Information Form and other continuous disclosure documents, is available on SEDAR at www.sedar.com under TransCanada Corporation.

Other selected consolidated financial information for 2001 to 2010 is found under the heading "Ten Year Financial Highlights" in the Supplementary Information section of the Company's Annual Report.

GLOSSARY OF TERMS

AcSB	Accounting Standards Board
AECL	Atomic Energy of Canada Ltd.
AGIA	Alaska Gasline Inducement Act
Alaska Pipeline Project	A proposed natural gas pipeline extending from Prudhoe Bay, Alaska to either Alberta or Valdez, Alaska
Alberta System	A natural gas transmission system in Alberta and B.C.
AOCI	Accumulated Other Comprehensive (Loss)/Income
American Natural Resources (ANR)	A natural gas transmission system extending from producing fields located primarily in Texas, Oklahoma, the Gulf of Mexico and U.S. midcontinent region to markets located primarily in Wisconsin, Michigan, Illinois, Ohio and Indiana, and regulated underground natural gas storage facilities in Michigan
APG	Aboriginal Pipeline Group
ARO	Asset retirement obligation
AUC	Alberta Utilities Commission
B.C.	British Columbia
Bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
Bear Creek	A natural gas-fired cogeneration plant near Grande Prairie, Alberta
Bécancour	A natural gas-fired cogeneration plant near Trois-Rivières, Québec
Bison	A natural gas pipeline extending from the Powder River Basin in Wyoming to Northern Border in North Dakota
BPC	BPC Generation Infrastructure Trust
BPRIA	Bruce Power Refurbishment Implementation Agreement
Broadwater	A proposed offshore LNG project in Long Island Sound, New York
Bruce A	A partnership interest in a nuclear power generation facility consisting of Units 1 to 4 of Bruce Power
Bruce B	A partnership interest in a nuclear power generation facility consisting of Units 5 to 8 of Bruce Power
Bruce Power	A nuclear power generation facility located northwest of Toronto, Ontario (Bruce A and Bruce B, collectively)
Calpine	Calpine Corporation
Canadian Mainline	A natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec
Cancarb	A waste-heat fuelled power plant at the Cancarb thermal carbon black facility in Medicine Hat, Alberta
CAPP	Canadian Association of Petroleum Producers
Carseland	A natural gas-fired cogeneration plant near Carseland, Alberta
Cartier Wind	Five wind farms in Gaspé, Québec, three of which are operational and two under construction
Chinook	A proposed power transmission line project that will originate in Montana and terminate in Nevada
CICA	Canadian Institute of Chartered Accountants
CO_2	Carbon dioxide
Coolidge	A simple-cycle, natural gas-fired peaking power generation station under construction in Coolidge, Arizona
CrossAlta	An underground natural gas storage facility near Crossfield, Alberta
Cushing Extension	Second phase of the Keystone oil pipeline delivering crude oil to Cushing, Oklahoma
DB Plans	Defined benefit pension plans
DC Plans	Defined contribution pension plans
DRP	Dividend Reinvestment and Share Purchase Plan
EBIT	Earnings before interest and taxes

EBITDA	Earnings before interest, taxes, depreciation and amortization
Edson	An underground natural gas storage facility near Edson, Alberta
EPA	Environmental Protection Agency (U.S.)
FCA	Fuel channel assemblies
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission (U.S.)
Foothills	A natural gas transmission system extending from central Alberta to the B.C./U.S. border and to the Saskatchewan/U.S. border
GAAP	Canadian generally accepted accounting principles
Gas Pacifico	A natural gas transmission system extending from Loma de la Lata, Argentina to Concepción, Chile
GHG	Greenhouse gas
Grandview	A natural gas-fired cogeneration plant in Saint John, New Brunswick
Great Lakes	A natural gas transmission system that connects to the Canadian Mainline and serves markets in Eastern Canada and the northeastern and midwestern U.S.
Gas Transmission Northwest (GTN)	A natural gas transmission system extending from the B.C./Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon
GTNC	Gas Transmission Northwest Company
Guadalajara	A natural gas pipeline under construction in Mexico extending from Manzanillo, Colima to Guadalajara, Jalisco
GWh	Gigawatt hours
Halton Hills	A natural gas-fired, combined-cycle power plant in Halton Hills, Ontario
HS&E	Health, safety and environment
HVDC	High voltage direct current
IASB	International Accounting Standards Board
IESO	Independent Electricity System Operator
IFRS	International Financial Reporting Standards
INNERGY	An industrial natural gas marketing company based in Concepción, Chile
Iroquois	A natural gas transmission system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to the northeastern U.S.
ISO	International Organization for Standardization
Keystone	Wood River/Patoka, Cushing Extension and U.S. Gulf Coast Expansion, collectively
Kibby Wind	A wind farm located in Kibby and Skinner townships in northwestern Franklin County, Maine
km	Kilometre(s)
LNG	Liquefied natural gas
MacKay River	A natural gas-fired cogeneration plant near Fort McMurray, Alberta
MD&A	Management's Discussion and Analysis
Mackenzie Gas Project (MGP)	A proposed natural gas pipeline extending from a point near Inuvik, Northwest Territories to the northern border of Alberta
mmcf/d	Million cubic feet per day
MOP	Maximum operating pressure
MW	Megawatt(s)
MWh	Megawatt hours
NCC	North Central Corridor
NEB	National Energy Board
NGTL	NOVA Gas Transmission Ltd.
North Baja	A natural gas transmission system extending from Arizona to the Baja California, Mexico/California border
Northern Border	A natural gas transmission system extending from a point near Monchy, Saskatchewan to the U.S. Midwest

NYISO	New York Independent System Operator
OCI	Other Comprehensive (Loss)/Income
OM&A	Operating, maintenance and administration
OMERS	Ontario Municipal Employees Retirement System
OPA	Ontario Power Authority
Ocean State Power (OSP)	A natural gas-fired, combined-cycle plant in Burrillville, Rhode Island
Palomar	A proposed pipeline extending from GTN to the Columbia River northwest of Portland
PCB	Polychlorinated biphenyls
PipeLines LP	TC PipeLines, LP
PJM Interconnection	A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia
Portland	A natural gas transmission system extending from a point near East Hereford, Québec to the northeastern U.S.
Portlands Energy	A natural gas-fired, combined-cycle power plant in Toronto, Ontario
PPA	Power purchase arrangement
PSD	Prevention of Significant Deterioration
PWU	Power Workers' Union Trust
Ravenswood	A natural gas- and oil-fired generating facility consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology located in Queens, New York
Redwater	A natural gas-fired cogeneration plant near Redwater, Alberta
RGGI	Regional Greenhouse Gas Initiative
ROE	Rate of return on common equity
RRA	Rate-regulated accounting
SEC	Securities and Exchange Commission (U.S.)
SEP	Society of Energy Professionals Trust
Sheerness	A coal-fired power generating facility near Hanna, Alberta
Sundance A	A coal-fired power generating facility near Wabamun, Alberta
Sundance B	A coal-fired power generating facility near Wabamun, Alberta
Tamazunchale	A natural gas pipeline in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi
TC Hydro	Hydroelectric generation assets in New Hampshire, Vermont and Massachusetts
TCPL	TransCanada PipeLines Limited
TCPL USA	TransCanada PipeLine USA Ltd.
Trans Québec & Maritimes (TQM)	A natural gas transmission system that connects with the Canadian Mainline near the Québec/Ontario border and transports natural gas to markets in Québec, and connects with Portland
TransAlta	TransAlta Corporation
TransCanada or the Company	TransCanada Corporation
TransGas	A natural gas transmission system extending from Mariquita to Cali in Colombia
Tuscarora	A natural gas transmission system extending from Malin, Oregon to Wadsworth, Nevada
U.S.	United States
U.S. GAAP	U.S. generally accepted accounting principles
U.S. Gulf Coast Expansion	A proposed extension and expansion of the Keystone oil pipeline to the U.S. Gulf Coast
VaR	Value-at-Risk
Ventures LP	A natural gas transmission system in Alberta supplying natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta
WCI	Western Climate Initiative
WCSB	Western Canada Sedimentary Basin
Wood River/ Patoka	First phase of the Keystone oil pipeline delivering crude oil to Wood River and Patoka in Illinois
Zephyr	A proposed power transmission line project originating in Wyoming and terminating in Nevada

Report of Management

The consolidated financial statements and Management's Discussion and Analysis (MD&A) included in this Annual Report are the responsibility of the management of TransCanada Corporation (TransCanada or the Company) and have been approved by the Board of Directors of the Company. The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP) and include amounts that are based on estimates and judgements. The MD&A is based on the Company's financial results. It compares the Company's financial and operating performance in 2010 to that in 2009, and highlights significant changes between 2009 and 2008. The MD&A should be read in conjunction with the consolidated financial statements and accompanying notes. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Management has designed and maintains a system of internal controls over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. The internal controls over financial reporting include management's communication to employees of policies that govern ethical business conduct.

Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal controls over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded, based on its evaluation, that internal controls over financial reporting are effective as of December 31, 2010, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The Board of Directors is responsible for reviewing and approving the financial statements and MD&A and ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors carries out these responsibilities primarily through the Audit Committee, which consists of independent, non-management directors. The Audit Committee meets with management at least five times a year and meets independently with internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing management's performance in carrying out its financial reporting responsibilities and reviewing the Annual Report, including the consolidated financial statements and MD&A, before these documents are submitted to the Board of Directors for approval. The internal and independent external auditors have access to the Audit Committee without the requirement to obtain prior management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The shareholders have appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with Canadian GAAP. The report of KPMG LLP outlines the scope of its examination and its opinion on the consolidated financial statements.

Russell K. Girling
President and
Chief Executive Officer

Donald R. Marchand
Executive Vice-President and
Chief Financial Officer

February 14, 2011

Auditors' Report

To the Shareholders of TransCanada Corporation

We have audited the accompanying consolidated financial statements of TransCanada Corporation and its subsidiaries, which comprise the consolidated balance sheet as at December 31, 2010 and 2009, the consolidated statements of income, comprehensive income, accumulated other comprehensive income, shareholders' equity and cash flows for each of the years in the three-year period ended December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgement, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinions.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of TransCanada Corporation and its subsidiaries as at December 31, 2010 and 2009 and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada

February 14, 2011

TRANSCANADA CORPORATION
CONSOLIDATED INCOME

Year ended December 31 (millions of dollars except per share amounts)	**2010**	2009	2008
Revenues	**8,064**	8,181	8,547
Operating and Other Expenses/(Income)			
Plant operating costs and other	**3,114**	3,213	2,976
Commodity purchases resold	**1,017**	831	1,429
Depreciation and amortization	**1,354**	1,377	1,247
Valuation provision for MGP (Note 7)	**146**	–	–
Calpine bankruptcy settlements (Note 18)	**–**	–	(279)
Write-down of Broadwater LNG project costs (Note 4)	**–**	–	41
	5,631	5,421	5,414
Financial Charges/(Income)			
Interest expense (Note 10)	**701**	954	943
Interest expense of joint ventures (Note 11)	**59**	64	72
Interest income and other	**(94)**	(121)	(54)
	666	897	961
Income before Income Taxes and Non-Controlling Interests	**1,767**	1,863	2,172
Income Taxes (Recovery)/Expense (Note 19)			
Current	**(141)**	30	526
Future	**521**	357	76
	380	387	602
Non-Controlling Interests (Note 15)	**115**	96	130
Net Income	**1,272**	1,380	1,440
Preferred Share Dividends (Note 17)	**45**	6	–
Net Income Applicable to Common Shares	**1,227**	1,374	1,440
Net Income per Share (Note 16)			
Basic	**$1.78**	$2.11	$2.53
Diluted	**$1.77**	$2.11	$2.52

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION

CONSOLIDATED CASH FLOWS

Year ended December 31 *(millions of dollars)*	**2010**	2009	2008
Cash Generated from Operations			
Net income	**1,272**	1,380	1,440
Depreciation and amortization	**1,354**	1,377	1,247
Future income taxes (Note 19)	**521**	357	76
Non-controlling interests (Note 15)	**115**	96	130
Valuation provision for MGP (Note 7)	**146**	–	–
Employee future benefits funding (in excess of)/lower than expense (Note 22)	**(69)**	(111)	17
Write-down of Broadwater LNG project costs (Note 4)	**–**	–	41
Other	**(8)**	(19)	70
	3,331	3,080	3,021
(Increase)/decrease in operating working capital (Note 23)	**(249)**	(90)	135
Net cash provided by operations	**3,082**	2,990	3,156
Investing Activities			
Capital expenditures	**(5,036)**	(5,417)	(3,134)
Deferred amounts and other	**(384)**	(594)	(484)
Acquisitions, net of cash acquired (Note 9)	**–**	(902)	(3,229)
Disposition of assets, net of current income taxes	**–**	–	28
Net cash used in investing activities	**(5,420)**	(6,913)	(6,819)
Financing Activities			
Dividends on common and preferred shares (Notes 16 and 17)	**(754)**	(728)	(577)
Distributions paid to non-controlling interests	**(112)**	(100)	(141)
Notes payable issued/(repaid), net (Note 20)	**474**	(244)	1,293
Long-term debt issued, net of issue costs (Note 10)	**2,371**	3,267	2,197
Reduction of long-term debt	**(494)**	(1,005)	(840)
Long-term debt of joint ventures issued (Note 11)	**177**	226	173
Reduction of long-term debt of joint ventures	**(254)**	(246)	(120)
Common shares issued, net of issue costs (Note 16)	**26**	1,820	2,384
Preferred shares issued, net of issue costs (Note 17)	**679**	539	–
Partnership units of subsidiary issued, net of issue costs (Note 9)	**–**	193	–
Net cash provided by financing activities	**2,113**	3,722	4,369
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(8)**	(110)	98
(Decrease)/Increase in Cash and Cash Equivalents	**(233)**	(311)	804
Cash and Cash Equivalents			
Beginning of year	**997**	1,308	504
Cash and Cash Equivalents			
End of year	**764**	997	1,308

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION
CONSOLIDATED BALANCE SHEET

December 31 *(millions of dollars)*	**2010**	2009
ASSETS		
Current Assets		
Cash and cash equivalents	**764**	997
Accounts receivable	**1,271**	966
Inventories	**425**	511
Other	**777**	701
	3,237	3,175
Plant, Property and Equipment (Note 5)	**36,244**	32,879
Goodwill (Note 6)	**3,570**	3,763
Regulatory Assets (Note 14)	**1,512**	1,524
Intangibles and Other Assets (Note 7)	**2,026**	2,500
	46,589	43,841
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable (Note 20)	**2,092**	1,687
Accounts payable	**2,243**	2,195
Accrued interest	**367**	377
Current portion of long-term debt (Note 10)	**894**	478
Current portion of long-term debt of joint ventures (Note 11)	**65**	212
	5,661	4,949
Regulatory Liabilities (Note 14)	**314**	385
Deferred Amounts (Note 13)	**694**	743
Future Income Taxes (Note 19)	**3,222**	2,856
Long-Term Debt (Note 10)	**17,028**	16,186
Long-Term Debt of Joint Ventures (Note 11)	**801**	753
Junior Subordinated Notes (Note 12)	**985**	1,036
	28,705	26,908
Non-Controlling Interests (Note 15)	**1,157**	1,174
Shareholders' Equity	**16,727**	15,759
	46,589	43,841

Commitments, Contingencies and Guarantees (Note 24)

The accompanying notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:

Russell K. Girling
Director

Kevin E. Benson
Director

TRANSCANADA CORPORATION
CONSOLIDATED COMPREHENSIVE INCOME

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Net Income	**1,272**	1,380	1,440
Other Comprehensive (Loss)/Income, Net of Income Taxes			
Change in foreign currency translation gains and losses on net investments in foreign operations[1]	**(180)**	(471)	571
Change in gains and losses on financial derivatives to hedge the net investments in foreign operations[2]	**89**	258	(589)
Change in gains and losses on derivative instruments designated as cash flow hedges[3]	**(137)**	77	(60)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[4]	**(17)**	(24)	(23)
Change in gains and losses on available-for-sale financial instruments[5]	**–**	–	2
Other Comprehensive Loss	**(245)**	(160)	(99)
Comprehensive Income	**1,027**	1,220	1,341

(1) Net of income tax expense of $65 million in 2010 (2009 – $92 million expense; 2008 – $104 million recovery).

(2) Net of income tax expense of $37 million in 2010 (2009 – $124 million expense; 2008 – $303 million recovery).

(3) Net of income tax recovery of $95 million in 2010 (2009 – $7 million expense; 2008 – $41 million recovery).

(4) Net of income tax expense of $21 million in 2010 (2009 – $9 million expense; 2008 – $19 million recovery).

(5) Net of income tax expense of nil in 2008.

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION

CONSOLIDATED ACCUMULATED OTHER COMPREHENSIVE (LOSS)/INCOME

(millions of dollars)	Currency Translation Adjustments	Cash Flow Hedges and Other	Total
Balance at January 1, 2008	(361)	(12)	(373)
Change in foreign currency translation gains and losses on net investments in foreign operations[1]	571	–	571
Change in gains and losses on financial derivatives to hedge the net investments in foreign operations[2]	(589)	–	(589)
Change in gains and losses on derivative instruments designated as cash flow hedges[3]	–	(60)	(60)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[4]	–	(23)	(23)
Change in gains and losses on available-for-sale financial instruments[5]	–	2	2
Balance at December 31, 2008	(379)	(93)	(472)
Change in foreign currency translation gains and losses on net investments in foreign operations[1]	(471)	–	(471)
Change in gains and losses on financial derivatives to hedge the net investments in foreign operations[2]	258	–	258
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]	–	(24)	(24)
Balance at December 31, 2009	(592)	(40)	(632)
Change in foreign currency translation gains and losses on net investments in foreign operations[1]	**(180)**	**–**	**(180)**
Change in gains and losses on financial derivatives to hedge the net investments in foreign operations[2]	**89**	**–**	**89**
Change in gains and losses on derivative instruments designated as cash flow hedges[3]	**–**	**(137)**	**(137)**
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges pertaining to prior periods[4][6]	**–**	**(17)**	**(17)**
Balance at December 31, 2010	**(683)**	**(194)**	**(877)**

(1) Net of income tax expense of $65 million in 2010 (2009 – $92 million expense; 2008 – $104 million recovery).

(2) Net of income tax expense of $37 million in 2010 (2009 – $124 million expense; 2008 – $303 million recovery).

(3) Net of income tax recovery of $95 million in 2010 (2009 – $7 million expense; 2008 – $41 million recovery).

(4) Net of income tax expense of $21 million in 2010 (2009 – $9 million expense; 2008 – $19 million recovery).

(5) Net of income tax expense of nil in 2008.

(6) Losses related to cash flow hedges reported in AOCI and expected to be reclassified to Net Income in 2011 are estimated to be $94 million ($60 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.

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION
CONSOLIDATED SHAREHOLDERS' EQUITY

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Common Shares			
Balance at beginning of year	**11,338**	9,264	6,662
Shares issued under dividend reinvestment plan (Note 16)	**378**	254	218
Proceeds from shares issued on exercise of stock options (Note 16)	**29**	28	21
Proceeds from shares issued under public offering, net of issue costs (Note 16)	**–**	1,792	2,363
Balance at end of year	**11,745**	11,338	9,264
Preferred Shares			
Balance at beginning of year	**539**	–	–
Proceeds from shares issued under public offering, net of issue costs (Note 17)	**685**	539	–
Balance at end of year	**1,224**	539	–
Contributed Surplus			
Balance at beginning of year	**328**	279	276
Issuance of stock options, net of exercises	**3**	2	3
Increased ownership in PipeLines LP (Note 9)	**–**	47	–
Balance at end of year	**331**	328	279
Retained Earnings			
Balance at beginning of year	**4,186**	3,827	3,220
Net income	**1,272**	1,380	1,440
Common share dividends	**(1,109)**	(1,015)	(833)
Preferred share dividends	**(45)**	(6)	–
Balance at end of year	**4,304**	4,186	3,827
Accumulated Other Comprehensive (Loss)/Income			
Balance at beginning of year	**(632)**	(472)	(373)
Other comprehensive loss	**(245)**	(160)	(99)
Balance at end of year	**(877)**	(632)	(472)
	3,427	3,554	3,355
Total Shareholders' Equity	**16,727**	15,759	12,898

The accompanying notes to the consolidated financial statements are an integral part of these statements.

TRANSCANADA CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 DESCRIPTION OF TRANSCANADA'S BUSINESS

TransCanada Corporation (TransCanada or the Company) is a leading North American energy company. TransCanada operates in three business segments, Natural Gas Pipelines, Oil Pipelines and Energy, each of which offers different products and services.

Natural Gas Pipelines
The Natural Gas Pipelines segment consists of the Company's investments in regulated natural gas pipelines and regulated natural gas storage facilities. Through its Natural Gas Pipelines segment, TransCanada owns and operates:

- a natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec (Canadian Mainline);
- a natural gas transmission system in Alberta and northeastern British Columbia (B.C.) (Alberta System);
- a natural gas transmission system extending from producing fields primarily located in Texas, Oklahoma, the Gulf of Mexico and Louisiana to markets primarily located in Wisconsin, Michigan, Illinois, Ohio and Indiana, and to regulated natural gas storage facilities in Michigan (ANR);
- a natural gas transmission system extending from the B.C./Idaho border to the Oregon/California border (GTN);
- a natural gas transmission system extending from central Alberta to the B.C./Idaho border and to the Saskatchewan/Montana border (Foothills);
- a natural gas transmission system extending from the Powder River Basin in Wyoming to Northern Border in North Dakota (Bison);
- natural gas transmission systems in Alberta that supply natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta (Ventures LP); and
- a natural gas transmission system in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi (Tamazunchale).

Through its Natural Gas Pipelines segment, TransCanada operates and has ownership interests in natural gas pipeline systems as follows:

- a 53.6 per cent direct ownership interest in a natural gas transmission system that connects to the Canadian Mainline and serves markets in Eastern Canada and the northeastern and midwestern United States (U.S.) (Great Lakes);
- a 61.7 per cent interest in a natural gas transmission system that extends from a point near East Hereford, Québec, to the northeastern U.S. (Portland);
- a 50 per cent interest in a natural gas transmission system that connects with the Canadian Mainline near the Québec/Ontario border and transports natural gas to markets in Québec and to the Portland system (TQM); and
- a 38.2 per cent controlling interest in TC PipeLines, LP (PipeLines LP), whose ownership interests in pipelines operated by TransCanada are as follows:
  - a 46.4 per cent interest in Great Lakes, in which TransCanada has a combined 71.3 per cent effective ownership interest through PipeLines LP and a direct interest described above;
  - a 50 per cent interest in a natural gas transmission system extending from a point near Monchy, Saskatchewan, to the U.S. Midwest (Northern Border), in which TransCanada has a 19.1 per cent effective ownership interest through PipeLines LP;
  - a 100 per cent interest in a natural gas transmission system extending from Arizona to Baja California at the Mexico/California border (North Baja), in which TransCanada has a 38.2 per cent effective ownership interest through PipeLines LP; and
  - a 100 per cent interest in a natural gas transmission system extending from Malin, Oregon, to Wadsworth, Nevada (Tuscarora), in which TransCanada has a 38.2 per cent effective ownership interest through PipeLines LP.

TransCanada does not operate but has ownership interests in natural gas pipelines and natural gas marketing activities as follows:

- a 44.5 per cent interest in a natural gas transmission system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to customers in the northeastern U.S. (Iroquois);
- a 46.5 per cent interest in a natural gas transmission system extending from Mariquita to Cali in Colombia (TransGas); and
- a 30 per cent interest in a natural gas transmission system extending from Loma de la Lata, Argentina to Concepción, Chile (Gas Pacifico), and in an industrial natural gas marketing company based in Concepción (INNERGY).

TransCanada is constructing and expects to operate a natural gas pipeline in Mexico that will transport natural gas from Manzanillo to Guadalajara (Guadalajara).

Oil Pipelines
The Oil Pipelines segment consists of a wholly owned and operated crude oil pipeline extending from Hardisty, Alberta to U.S. markets at Wood River and Patoka in Illinois (Wood River/Patoka) and from Steele City, Nebraska to Cushing, Oklahoma (Cushing Extension). The

Company plans to expand and extend the oil pipeline to the U.S. Gulf Coast (U.S. Gulf Coast Expansion) (collectively, Keystone) with physical construction to commence upon receipt of final permits.

Energy
The Energy segment primarily consists of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities. Through its Energy segment, the Company owns and operates:

- natural gas-fired cogeneration plants in Alberta at Carseland, Redwater, Bear Creek and MacKay River;
- a waste-heat fuelled power plant at the Cancarb thermal carbon black facility in Medicine Hat, Alberta (Cancarb);
- a natural gas- and oil-fired generating facility in Queens, New York, consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology (Ravenswood);
- a natural gas-fired, combined-cycle power plant in Halton Hills, Ontario (Halton Hills);
- hydroelectric generation assets located in New Hampshire, Vermont and Massachusetts (TC Hydro);
- a natural gas-fired, combined-cycle plant in Burrillville, Rhode Island (Ocean State Power);
- a natural gas-fired cogeneration plant near Trois-Rivières, Québec (Bécancour);
- a natural gas-fired cogeneration plant near Saint John, New Brunswick (Grandview);
- a natural gas storage facility near Edson, Alberta (Edson); and
- a wind farm located in Kibby and Skinner townships in northwestern Franklin County, Maine (Kibby Wind).

TransCanada does not operate but has ownership interests in power generation plants and non-regulated natural gas storage facilities as follows:

- a 48.8 per cent partnership interest and a 31.6 per cent partnership interest in the nuclear power generation facilities of Bruce A and Bruce B (collectively Bruce Power), respectively, located near Tiverton, Ontario;
- a 50 per cent interest in a natural gas-fired, combined-cycle plant in Toronto, Ontario (Portlands Energy);
- a 62 per cent interest in the Baie-des-Sables, Anse-à-Valleau and Carleton wind farms, three of five planned wind farms in Gaspé, Québec (Cartier Wind); and
- a 60 per cent interest in an underground natural gas storage facility near Crossfield, Alberta (CrossAlta).

TransCanada also has long-term power purchase arrangements (PPA) in place for:

- 100 per cent of the production of the Sundance A power facilities and 50 per cent of the production of the Sundance B power facilities near Wabamun, Alberta; and
- 756 megawatts (MW) of generating capacity from the Sheerness power facility near Hanna, Alberta.

TransCanada has interests in the following Energy projects which are under construction and which it expects to operate:

- a natural gas-fired, simple-cycle peaking power plant in Coolidge, Arizona (Coolidge); and
- a 62 per cent interest in the Gros-Morne and Montagne-Sèche wind farms, the fourth and fifth wind farms of Cartier Wind.

NOTE 2 ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with Canadian GAAP. Amounts are stated in Canadian dollars unless otherwise indicated. Certain comparative figures have been reclassified to conform with the current year's presentation.

In preparing these financial statements, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies summarized below.

Basis of Presentation
The consolidated financial statements include the accounts of TransCanada and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control. To the extent there are interests owned by other parties, these interests are included in Non-Controlling Interests. TransCanada proportionately consolidates its share of the accounts of joint ventures in which the Company is able

to exercise joint control. TransCanada uses the equity method of accounting for investments over which the Company is able to exercise significant influence.

Regulation

The Canadian regulated natural gas pipelines are subject to the authority of the National Energy Board (NEB) of Canada. Prior to April 2009, the Alberta System was regulated by the Alberta Utilities Commission (AUC). The natural gas pipelines and regulated storage assets in the U.S. are subject to the authority of the U.S. Federal Energy Regulatory Commission (FERC). The Company's natural gas transmission operations are regulated with respect to construction, operations and the determination of tolls. The timing of recognition of certain revenues and expenses in these rate-regulated businesses may differ from that otherwise expected in non-rate-regulated businesses under Canadian GAAP to appropriately reflect the economic impact of the regulators' decisions regarding revenues and tolls.

The NEB in Canada and FERC in the U.S. regulate construction and operations of Keystone, the Company's oil pipeline. The Company does not apply rate-regulated accounting (RRA) on its oil pipeline and, as a result, the regulators' decisions regarding operations and tolls on the oil pipeline generally do not have an impact on timing of recognition of revenues and expenses.

Revenue Recognition

Canadian Natural Gas Pipelines

Revenues from Canadian natural gas pipelines subject to rate regulation are recognized in accordance with decisions made by the NEB. The Company's Canadian natural gas pipeline rates are based on revenue requirements designed to recover the costs of providing natural gas transportation services, which include an appropriate return of and return on capital, as approved by the NEB. The Company's Canadian natural gas pipelines are not subject to risks related to variances in revenues and most costs. These variances are subject to deferral treatment and are recovered or refunded in future rates. The Company's Canadian natural gas pipelines are periodically subject to incentive mechanisms, as negotiated with shippers and approved by the NEB. These mechanisms can result in the Company recognizing more or less revenue than required to account for the incentives. Revenues are recognized on firm contracted capacity over the contract period. Revenues from interruptible or volumetric-based services are recorded when physical delivery is made. Revenues recognized prior to the NEB's decision on rates reflect the NEB's last approved return on equity assumptions. Adjustments to revenue are recorded when the NEB decision is received.

U.S. Natural Gas Pipelines

Revenues from U.S. natural gas pipelines subject to rate regulation are recorded in accordance with FERC rules and regulations. The Company's U.S. natural gas pipeline revenues are generally based on quantity of gas delivered or contracted capacity. Revenues are recognized on firm contracted capacity over the contract period. Revenues from interruptible or volumetric-based services are recorded when physical delivery is made.

Oil Pipelines

The Company's oil pipeline revenues are generated from the transportation of crude oil and contractual arrangements for committed capacity. Transportation revenues are recognized in the period the product is delivered. Transportation revenues are based on actual volumes and rates and are adjusted to reflect under-recovery or over-recovery of certain transportation costs. Revenues earned from contract capacity arrangements are recognized in the period in which the capacity is made available.

Energy

i) Power

Revenues from the Company's power business are primarily derived from the sale of electricity through energy marketing activities and from the sale of unutilized natural gas fuel, which are recorded at the time of delivery. Revenues also include capacity payments and ancillary services, which are earned monthly, and revenues earned through the use of energy derivative contracts. The accounting for energy derivative contracts is described in the Financial Instruments section of this note.

ii) Natural Gas Storage

Revenues earned from providing natural gas storage services are recognized in accordance with the terms of the natural gas storage contracts, which is generally over the term of the contract. Revenues earned on the sale of proprietary natural gas are recorded in the month of delivery. Forward contracts for the purchase or sale of natural gas, as well as proprietary natural gas inventory in storage, are recorded at fair value with changes in fair value recorded in Revenues.

Cash and Cash Equivalents

The Company's cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

Inventories

Inventories primarily consist of materials and supplies, including spare parts and fuel, and are carried at the lower of average cost and net realizable value. The Company values its proprietary natural gas inventory in storage at fair value, measured using a weighted average of forward prices for the following four months, less selling costs. To record inventory at fair value, TransCanada has designated its natural gas storage business as a broker/trader business that purchases and sells natural gas on a back-to-back basis. The Company records its net proprietary natural gas storage sales and purchases in Revenues. All changes in the fair value of proprietary natural gas inventory in storage are reflected in Inventories and in Revenues.

Plant, Property and Equipment

Natural Gas Pipelines

Plant, property and equipment for natural gas pipelines are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and compression equipment are depreciated at annual rates ranging from one per cent to six per cent, and metering and other plant equipment are depreciated at various rates. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. The cost of regulated natural gas pipelines includes an allowance for funds used during construction (AFUDC) consisting of a debt component and an equity component based on the rate of return on rate base approved by regulators. This allowance is reflected as an increase in the cost of the assets in Plant, Property and Equipment. The equity component of AFUDC is a non-cash expenditure. Interest is capitalized during construction of non-regulated natural gas pipelines.

When regulated natural gas pipelines retire plant, property and equipment from service, the original book cost is removed from the gross plant amount and recorded as a reduction to accumulated depreciation. Costs incurred to remove a plant from service, net of any salvage proceeds, are also recorded in accumulated depreciation.

Oil Pipelines

Plant, property and equipment for oil pipelines are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and pumping equipment are depreciated at annual rates ranging from approximately two per cent to 2.5 per cent, and other plant and equipment are depreciated at various rates. The cost of these assets includes interest capitalized during construction.

Energy

Major power generation and natural gas storage plant, equipment and structures are recorded at cost and, once the assets are ready for their intended use, depreciated by major component on a straight-line basis over their estimated service lives at average annual rates ranging from two per cent to 20 per cent. Nuclear power generation assets under capital lease are recorded initially at the present value of minimum lease payments at the inception of the lease and amortized on a straight-line basis over the shorter of their useful life and the remaining lease term. Other equipment is depreciated at various rates. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. Interest is capitalized on facilities under construction.

Corporate

Corporate plant, property and equipment are recorded at cost and depreciated on a straight-line basis over their estimated useful lives at average annual rates ranging from three per cent to 20 per cent.

Impairment of Long-Lived Assets

The Company reviews long-lived assets, such as plant, property and equipment, and intangible assets for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the purchase method of accounting and, accordingly, the assets and liabilities of the acquired entities are recorded at their estimated fair value at the date of acquisition. Goodwill is not amortized and is tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset might be impaired. An initial test is done by comparing the fair value of the operations, which includes goodwill, to the book value of each reporting unit. If the fair value is less than book value, an impairment is indicated and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of goodwill exceeds the calculated implied fair value of goodwill, an impairment charge is recorded.

Power Purchase Arrangements

A PPA is a long-term contract for the purchase or sale of power on a predetermined basis. The initial payments for the Company's PPAs were deferred in Other Assets and amortized on a straight-line basis over the term of the contracts, which expire in 2017 and 2020. The PPAs under which TransCanada buys power are accounted for as operating leases. A portion of these PPAs has been subleased to third parties under similar terms and conditions. The subleases are accounted for as operating leases and TransCanada records the margin earned from the subleases as a component of Revenues.

Stock Options

TransCanada's Stock Option Plan permits options for the purchase of common shares to be awarded to certain employees, including officers. The contractual life of options granted in 2003 and thereafter and of options granted prior to 2003 is seven years and 10 years, respectively. The Company uses the Black-Scholes model to determine fair value of the options on their grant date. Options may be exercised at a price determined at the time the option is awarded and vest 33.3 per cent on the anniversary date in each of the three years following the award. Forfeiture of stock options results from their expiration, and if not previously vested, upon resignation or retirement of the option holder or upon termination of the option holder's employment. Stock options become null and void upon forfeiture. The Company records compensation expense over the three-year vesting period, assuming a 15 per cent forfeiture rate, with an offset to Contributed Surplus. This charge is reflected in Corporate. Upon exercise of stock options, adjusted for forfeited stock options, amounts originally recorded against Contributed Surplus are reclassified to Common Shares.

Income Taxes

The Company uses the liability method of accounting for income taxes. This method requires the recognition of future income tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Changes to these balances are recognized in income in the period during which they occur except for changes in balances related to the Canadian Mainline, Alberta System and Foothills, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Foreign Currency Translation

The Company's foreign operations are self-sustaining and are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated at the period-end exchange rates and items included in the Consolidated Statements of Income, Shareholders' Equity, Comprehensive Income, Accumulated Other Comprehensive (Loss)/Income (AOCI) and Cash Flows are translated at the exchange rates in effect at the time of the transaction. Translation adjustments are reflected in Other Comprehensive (Loss)/Income (OCI).

Exchange gains and losses on monetary assets and liabilities are recorded in income except for exchange gains and losses on the foreign currency debt related to the Canadian Mainline, Alberta System and Foothills, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Financial Instruments

The Company initially records all financial instruments on the Balance Sheet at fair value. Where possible, fair value is determined by reference to quoted market prices. In the absence of quoted prices, other pricing and valuation techniques are used that maximize the use of observable data. The entity's own credit risk and the credit risk of its counterparties are taken into consideration when measuring the fair value of financial assets and financial liabilities. Subsequent measurement of the financial instruments is based on their classification. Financial assets are classified into the following categories: held for trading, available for sale, held-to-maturity investments, and loans and receivables. Financial liabilities are classified as held for trading or as other financial liabilities.

Held-for-trading derivative financial assets and liabilities consist of swaps, options, forwards and futures. A financial asset or liability may be designated as held for trading when it is entered into with the intention of generating a profit. The Company has not designated any of its non-derivative financial assets or liabilities as held for trading. Commodity held-for-trading financial instruments are initially recorded at their fair value and changes to fair value are included in Revenues. Realized gains and losses on derivatives used to manage the Company's operating assets are presented on a net basis in Revenues. Changes in the fair value of interest rate held-for-trading instruments are recorded in Interest Expense and changes in the fair value of foreign exchange rate held-for-trading instruments are recorded in Interest Income and Other. Realized gains and losses are included in the same financial statement category as their underlying position upon settlement of the financial instrument.

The available-for-sale classification includes non-derivative financial assets that are designated as available for sale or are not included in any of the other three classifications. TransCanada's available-for-sale financial instruments include fixed-income securities held for self-insurance. These instruments are accounted for initially at their fair value and changes to fair value are recorded through OCI. Income from the settlement of available-for-sale financial assets is included in Interest Income and Other.

The held-to-maturity classification consists of non-derivative financial assets that are accounted for at their amortized cost using the effective interest method. The Company does not have any held-to-maturity financial assets.

Trade receivables, loans and other receivables with fixed or determinable payments that are not quoted in an active market are classified as Loans and Receivables and are measured at amortized cost using the effective interest method, net of any impairment. The Company's loans and receivables include trade accounts receivable, interest-bearing and non-interest-bearing third-party loans, and notes receivable. Interest and other income earned from these financial assets are recorded in Interest Income and Other.

Other financial liabilities consist of liabilities not classified as held for trading. Items in this financial instrument category are recognized at amortized cost using the effective interest method. Interest costs are included in Interest Expense and in Interest Expense of Joint Ventures.

The Company uses derivatives and other financial instruments to manage its exposure to changes in foreign currency exchange rates, interest rates and energy commodity prices. The Company also uses a combination of derivatives and U.S. dollar-denominated debt to manage the foreign currency exposure of its foreign operations.

All derivatives are recorded on the balance sheet at fair value, with the exception of non-financial derivatives that were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected normal purchase, sale or usage requirements. Derivatives used in hedging relationships are discussed further in the Hedges section of this note.

Derivatives embedded in other financial instruments or contracts (host instrument) are recorded as separate derivatives. Embedded derivatives are measured at fair value if their economic characteristics are not closely related to those of the host instrument, their terms are the same as those of a stand-alone derivative and the total contract is not held for trading or accounted for at fair value. When changes in the fair value of embedded derivatives are recorded separately, they are included in Net Income.

The recognition of gains and losses on the derivatives for the Canadian natural gas regulated pipelines exposures is determined through the regulatory process. The gains and losses on derivatives accounted for as part of RRA are deferred in Regulatory Assets or Regulatory Liabilities.

Transaction costs are defined as incremental costs that are directly attributable to the acquisition, issue or disposal of a financial instrument. The Company offsets long-term debt transaction costs against the associated debt and amortizes these costs using the effective interest method for all costs except those related to the Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of tolling mechanisms.

The Company records the fair value of its portion of material joint and several guarantees. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees. Guarantees are recorded as an increase to an investment account, Plant, Property and Equipment, or a charge to Net Income, and a corresponding liability is recorded in Deferred Amounts.

Hedges

The Company applies hedge accounting to arrangements that qualify for hedge accounting treatment, which include fair value and cash flow hedges, and to hedges of foreign currency exposures of net investments in self-sustaining foreign operations. Documentation is prepared at the inception of each hedging arrangement in order to qualify for hedge accounting treatment. In addition, the Company performs an assessment of effectiveness at the inception of the contract and at each reporting date. Hedge accounting is discontinued prospectively when the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk and these changes are recognized in Net Income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in Net Income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in Interest Income and Other and Interest Expense, respectively. When hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to Net Income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is initially recognized in OCI, while any ineffective portion is recognized in Net Income in the same financial statement category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in AOCI are reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, during the periods when the variability in cash flows of the hedged item affects Net Income or as the original hedged item settles. Gains and losses on derivatives are reclassified immediately to Net Income from AOCI when the hedged item is sold or terminated early, or when an anticipated transaction is no longer expected to occur.

The Company also enters into cash flow hedges and fair value hedges for activities subject to rate regulation. The gains and losses arising from changes in the fair value of these hedges can be recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as Regulatory Assets or Regulatory Liabilities. When the hedges are settled, the realized gains or losses are refunded to or collected from the ratepayers in subsequent years.

In hedging the foreign currency exposure of a net investment in a self-sustaining foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in OCI and the ineffective portion is recognized in Net Income. The amounts recognized previously in AOCI are reclassified to Net Income in the event the Company reduces its net investment in a foreign operation.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for asset retirement obligations (ARO) in the period in which it is incurred, when a legal obligation exists and a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted at the end of each period through charges to operating expenses.

The scope and timing of asset retirements related to regulated natural gas pipelines, oil pipelines and hydroelectric power plants is uncertain. As a result, the Company has not recorded an amount for ARO related to these assets, with the exception of certain abandoned facilities. The Company has not recorded an amount for ARO related to the nuclear assets, as Bruce Power leases the assets and the lessor is responsible for decommissioning liabilities under the lease agreement.

Environmental Liabilities

The Company records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. The estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations. The estimates are subject to revision in future periods based on actual costs incurred or new circumstances. Amounts expected to be recovered from other parties, including insurers, are recorded as an asset separate from the associated liability.

Emission allowances or credits purchased for compliance are recorded on the Balance Sheet at historical cost and expensed when they are retired. Compliance payments are expensed when incurred. Allowances granted to or internally generated by TransCanada are not attributed a value for accounting purposes. When required, TransCanada accrues emission liabilities on the Balance Sheet upon the generation or sale of power using the best estimate of the amount required to settle the obligation. Allowances and credits not used for compliance are sold and recorded in Revenues.

Employee Benefit and Other Plans

The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), a Savings Plan and other post-employment benefit plans. Contributions made by the Company to the DC Plans and Savings Plan are expensed when incurred. The cost of the DB Plans and other post-employment benefits received by employees is actuarially determined using the projected benefit method pro-rated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement age of employees and expected health care costs.

The DB Plans' assets are measured at fair value. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized over the average remaining service period of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

The Company has medium-term incentive plans, under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Certain of the Company's joint ventures sponsor DB Plans. The Company records its proportionate share of expenses, funding contributions and accrued benefit assets and liabilities related to these plans.

NOTE 3 ACCOUNTING CHANGES

Future Accounting Changes

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

The Canadian Institute of Chartered Accountants (CICA) Handbook Section 1582 "Business Combinations" is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting the standard is expected to have a material effect on the way the Company accounts for future business combinations. Entities adopting Section 1582 will also be required to adopt CICA Handbook Sections 1601 “Consolidated Financial Statements” and 1602 “Non-Controlling Interests”. Sections 1601 and 1602 will require Non-Controlling Interests to be presented as part of Shareholders’ Equity on the Balance Sheet. In addition, the income statement of the controlling parent will include 100 per cent of the subsidiary’s results and present the allocation of income between the controlling and non-controlling interests. These standards will be effective January 1, 2011. Changes resulting from the adoption of Section 1582 will be applied prospectively and changes resulting from the adoption of Sections 1601 and 1602 will be applied retrospectively.

International Financial Reporting Standards

The CICA Accounting Standards Board (AcSB) previously announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) effective January 1, 2011. As a U.S. Securities and Exchange Commission registrant, TransCanada prepares and files a “Reconciliation to United States GAAP” and has the option to prepare and file its consolidated financial statements using U.S. GAAP. Previously, TransCanada disclosed that, effective January 1, 2011, the Company expected to begin reporting under IFRS. As a result of the developments noted below, management expects that the Company will adopt U.S. GAAP effective January 1, 2012. The Company’s IFRS conversion project was proceeding as planned to meet the conversion date of January 1, 2011, prior to these developments.

In accordance with Canadian GAAP, TransCanada follows specific accounting policies unique to a rate-regulated business. These RRA standards allow the timing of recognition of certain expenses and revenues to differ from the timing that may otherwise be expected in a non-rate-regulated business under Canadian GAAP in order to appropriately reflect the economic impact of regulators’ decisions regarding the Company’s revenues and tolls. These timing differences are recorded as Regulatory Assets and Regulatory Liabilities on TransCanada’s Consolidated Balance Sheet and represent current rights and obligations regarding cash flows expected to be recovered from or refunded to customers based on decisions and approvals by the applicable regulatory authorities. At December 31, 2010, TransCanada reported regulatory assets of $1.8 billion and regulatory liabilities of $0.4 billion in addition to certain other impacts of RRA.

In July 2009, the IASB issued an Exposure Draft, Rate-Regulated Activities, which proposed a form of RRA under IFRS. At its September 2010 meeting, the IASB concluded that the development of RRA under IFRS requires further analysis and removed the RRA project from its current agenda. The IASB is considering what form a future project might take, if any, to address RRA. TransCanada does not expect a final RRA standard under IFRS to be effective for 2012.

In October 2010, the AcSB and the Canadian Securities Administrators amended their policies applicable to Canadian publicly accountable enterprises that use RRA in order to permit these entities to defer the adoption of IFRS for one year. Due to the continued uncertainty around the timing, scope and eventual adoption of an RRA standard under IFRS, TransCanada will defer its adoption of IFRS accordingly and continue preparing its consolidated financial statements in 2011 in accordance with Canadian GAAP, as defined by Part V of the CICA Handbook, in order to continue using RRA. TransCanada will continue to actively monitor IASB developments with respect to RRA and other IFRS.

U.S. GAAP Conversion Project

The impact of adopting U.S. GAAP is consistent with that currently reported in the Company’s publicly filed “Reconciliation to United States GAAP”. Significant changes to existing systems and processes are not required to implement U.S. GAAP as the Company’s primary accounting standard.

TransCanada’s IFRS conversion team has been redeployed to support the conversion to U.S. GAAP. All staff affected by the conversion will be provided with in-depth U.S. GAAP training and technical research will be conducted. The conversion team is led by a multi-disciplinary Steering Committee that provides directional leadership for the likely adoption of U.S. GAAP. Management also updates TransCanada’s Audit Committee on the progress of this project and on any pertinent developments related to IFRS at each Audit Committee meeting.

NOTE 4 SEGMENTED INFORMATION

During 2010, the Company recognized a separate segment, Oil Pipelines. Also during this period, Keystone Wood River/Patoka began delivering oil at reduced operating pressure due to regulatory restrictions. Therefore, the Company continued to classify Wood River/Patoka as under construction along with the Cushing Extension and the U.S. Gulf Coast Expansion. At December 31, 2010, Keystone capital costs were net of $99 million of operating cash flows relating to Wood River/Patoka. Total assets and capital expenditures relating to TransCanada’s Oil Pipelines segment are separately identified in this note. The corresponding items of segmented information have been restated, where necessary, in the 2009 and 2008 comparative figures.

Year ended December 31, 2010 (millions of dollars)	**Natural Gas Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**4,373**	**3,691**	**–**	**8,064**
Plant operating costs and other[1]	**(1,458)**	**(1,557)**	**(99)**	**(3,114)**
Commodity purchases resold	**–**	**(1,017)**	**–**	**(1,017)**
Depreciation and amortization	**(977)**	**(377)**	**–**	**(1,354)**
Valuation provision for MGP	**(146)**	**–**	**–**	**(146)**
	1,792	**740**	**(99)**	**2,433**
Interest expense				**(701)**
Interest expense of joint ventures				**(59)**
Interest income and other				**94**
Income taxes				**(380)**
Non-controlling interests				**(115)**
Net Income				**1,272**
Preferred share dividends				**(45)**
Net Income Applicable to Common Shares				**1,227**

(1) In 2010, Natural Gas Pipelines included $17 million of general, administrative and support costs relating to Keystone.

Year ended December 31, 2009 (millions of dollars)	**Natural Gas Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	4,729	3,452	–	8,181
Plant operating costs and other	(1,607)	(1,489)	(117)	(3,213)
Commodity purchases resold	–	(831)	–	(831)
Depreciation and amortization	(1,030)	(347)	–	(1,377)
	2,092	785	(117)	2,760
Interest expense				(954)
Interest expense of joint ventures				(64)
Interest income and other				121
Income taxes				(387)
Non-controlling interests				(96)
Net Income				1,380
Preferred share dividends				(6)
Net Income Applicable to Common Shares				1,374

Year ended December 31, 2008 (millions of dollars)	**Natural Gas Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	4,650	3,897	–	8,547
Plant operating costs and other	(1,614)	(1,258)	(104)	(2,976)
Commodity purchases resold	–	(1,429)	–	(1,429)
Depreciation and amortization	(989)	(258)	–	(1,247)
Calpine bankruptcy settlements	279	–	–	279
Write-down of Broadwater LNG project costs[1]	–	(41)	–	(41)
	2,326	911	(104)	3,133
Interest expense				(943)
Interest expense of joint ventures				(72)
Interest income and other				54
Income taxes				(602)
Non-controlling interests				(130)
Net Income				1,440

(1) In 2008, TransCanada wrote down $41 million of capitalized costs related to the Broadwater liquefied natural gas (LNG) project after the New York Department of State rejected a proposal to construct this facility.

TOTAL ASSETS

December 31 (millions of dollars)	**2010**	2009
Natural Gas Pipelines	**23,592**	23,724
Oil Pipelines	**8,501**	5,784
Energy	**12,847**	12,477
Corporate	**1,649**	1,856
	46,589	43,841

GEOGRAPHIC INFORMATION

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Revenues[1]			
Canada – domestic	**4,368**	5,079	4,551
Canada – export	**838**	756	1,125
United States and other	**2,858**	2,346	2,871
	8,064	8,181	8,547

[1] Revenues are attributed based on the country in which the product or service originated.

December 31 (millions of dollars)	**2010**	2009
Plant, Property and Equipment		
Canada	**21,561**	20,266
United States and other	**14,683**	12,613
	36,244	32,879

CAPITAL EXPENDITURES

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Natural Gas Pipelines	**1,196**	965	916
Oil Pipelines	**2,696**	2,939	938
Energy	**1,129**	1,487	1,266
Corporate	**15**	26	14
	5,036	5,417	3,134

NOTE 5 PLANT, PROPERTY AND EQUIPMENT

December 31 (millions of dollars)	2010 Cost	2010 Accumulated Depreciation	2010 Net Book Value	2009 Cost	2009 Accumulated Depreciation	2009 Net Book Value
Natural Gas Pipelines[1]						
Canadian Mainline						
Pipeline	**8,768**	**4,730**	**4,038**	8,752	4,501	4,251
Compression	**3,385**	**1,651**	**1,734**	3,379	1,529	1,850
Metering and other	**381**	**167**	**214**	364	153	211
	12,534	**6,548**	**5,986**	12,495	6,183	6,312
Under construction	**14**	**–**	**14**	27	–	27
	12,548	**6,548**	**6,000**	12,522	6,183	6,339
Alberta System						
Pipeline	**6,528**	**2,917**	**3,611**	6,002	2,777	3,225
Compression	**1,707**	**1,045**	**662**	1,696	983	713
Metering and other	**909**	**378**	**531**	879	342	537
	9,144	**4,340**	**4,804**	8,577	4,102	4,475
Under construction	**71**	**–**	**71**	281	–	281
	9,215	**4,340**	**4,875**	8,858	4,102	4,756
ANR						
Pipeline	**858**	**96**	**762**	848	79	769
Compression	**507**	**74**	**433**	489	65	424
Metering and other	**548**	**74**	**474**	646	67	579
	1,913	**244**	**1,669**	1,983	211	1,772
Under construction	**7**	**–**	**7**	23	–	23
	1,920	**244**	**1,676**	2,006	211	1,795
GTN						
Pipeline	**1,079**	**233**	**846**	1,135	205	930
Compression	**395**	**67**	**328**	414	59	355
Metering and other	**78**	**19**	**59**	93	22	71
	1,552	**319**	**1,233**	1,642	286	1,356
Under construction	**5**	**–**	**5**	22	–	22
	1,557	**319**	**1,238**	1,664	286	1,378
Joint Ventures and Others						
Great Lakes	**1,540**	**698**	**842**	1,608	694	914
Foothills	**1,650**	**975**	**675**	1,645	917	728
Northern Border	**1,252**	**608**	**644**	1,316	613	703
Other[2]	**2,913**	**633**	**2,280**	2,307	587	1,720
	7,355	**2,914**	**4,441**	6,876	2,811	4,065
	32,595	**14,365**	**18,230**	31,926	13,593	18,333
Oil Pipelines						
Keystone						
Under construction[3]	**8,184**	**–**	**8,184**	5,305	–	5,305
	8,184	**–**	**8,184**	5,305	–	5,305
Energy						
Nuclear[4]	**1,586**	**536**	**1,050**	1,536	451	1,085
Natural Gas – Ravenswood	**1,710**	**144**	**1,566**	1,712	82	1,630
Natural Gas – Other[5][6]	**2,767**	**588**	**2,179**	2,032	522	1,510
Hydro	**599**	**69**	**530**	625	56	569
Wind[7]	**659**	**65**	**594**	611	41	570
Natural Gas Storage	**423**	**67**	**356**	418	56	362
Other	**160**	**96**	**64**	156	89	67
	7,904	**1,565**	**6,339**	7,090	1,297	5,793
Under construction – Nuclear[8]	**2,678**	**–**	**2,678**	2,078	–	2,078
Under construction – Other[9]	**728**	**–**	**728**	1,287	–	1,287
	11,310	**1,565**	**9,745**	10,455	1,297	9,158
Corporate	**125**	**40**	**85**	110	27	83
	52,214	**15,970**	**36,244**	47,796	14,917	32,879

(1) In 2010, the Company capitalized $35 million (2009 – $33 million) relating to the equity portion of AFUDC for natural gas pipelines with a corresponding amount recorded in Interest Income and Other.

(2) Includes in-service assets of Portland, Iroquois, TQM, North Baja, Tamazunchale, Ventures LP and Tuscarora, and under construction amounts of $622 million (2009 – $200 million) and $277 million (2009 – $29 million) for Bison and Guadalajara, respectively. Bison went into service in January 2011.

(3) Includes $1.4 billion at December 31, 2010 relating to the Keystone U.S. Gulf Coast Expansion. This phase of Keystone remains subject to regulatory approvals.

(4) Includes assets under capital lease relating to Bruce Power.

(5) Includes facilities with long-term PPAs that are accounted for as operating leases. The cost and accumulated depreciation of these facilities were $89 million and $19 million, respectively, at December 31, 2010 (2009 – $93 million and $17 million, respectively). Revenues of $15 million were recognized in 2010 (2009 – $15 million; 2008 – $14 million) through the sale of electricity under the related PPAs.

(6) Includes Halton Hills effective September 1, 2010.

(7) Includes phase two of Kibby Wind effective October 2010.

(8) Nuclear assets under construction primarily includes expenditures for the refurbishment and restart of Bruce A.

(9) Other Energy assets under construction at December 31, 2010 includes amounts for Coolidge and two Cartier Wind farms, Gros-Morne and Montagne-Sèche.

NOTE 6 GOODWILL

The Company has recorded the following goodwill on its acquisitions in the U.S.:

(millions of dollars)	Natural Gas Pipelines	Energy	Total
Balance at January 1, 2009	3,382	1,015	4,397
Foreign exchange	(491)	(143)	(634)
Balance at December 31, 2009	2,891	872	3,763
Foreign exchange	**(144)**	**(49)**	**(193)**
Balance at December 31, 2010	**2,747**	**823**	**3,570**

NOTE 7 INTANGIBLES AND OTHER ASSETS

December 31 (millions of dollars)	**2010**	2009
PPAs[1]	**539**	593
Employee benefit plans (Note 22)	**473**	383
Fair value of derivative contracts (Note 18)	**374**	260
Loans and advances[2]	**241**	417
Equity investments[3]	**78**	84
Margin calls	**76**	91
Deferred project development costs[4]	**–**	470
Other	**245**	202
	2,026	2,500

(1) The following amounts related to PPAs are included in the consolidated financial statements:

	2010			2009		
December 31 (millions of dollars)	**Cost**	**Accumulated Amortization**	**Net Book Value**	Cost	Accumulated Amortization	Net Book Value
PPAs	**919**	**380**	**539**	915	322	593

Amortization expense for the PPAs was $58 million for the year ended December 31, 2010 (2009 and 2008 – $58 million). The expected annual amortization expense in each of the next five years is $57 million.

(2) As at December 31, 2010, TransCanada held a $281 million (2009 – $317 million) note receivable from the seller of Ravenswood which bears interest at 6.75 per cent and matures in 2039. Loans and advances includes $241 million (2009 – $274 million) of this note receivable.

(3) The balance primarily relates to the Company's 46.5 per cent ownership interest in TransGas.

(4) At December 31, 2009, $470 million related to the Keystone U.S. Gulf Coast Expansion. This project is included in Plant, Property and Equipment at December 31, 2010.

Advances to Aboriginal Pipeline Group

The Mackenzie Delta gas producers, the Aboriginal Pipeline Group (APG) and TransCanada have an agreement governing TransCanada's role in the Mackenzie Gas Project (MGP). The project is expected to result in a natural gas pipeline being constructed from Inuvik, Northwest Territories, to the northern border of Alberta, where it would connect to the Alberta System. Under the agreement, TransCanada agreed to finance the APG for its one-third share of project pre-development costs.

The MGP proponents continue to pursue the required regulatory approvals for the project and the Canadian government's support of an acceptable fiscal framework. In December 2010, the NEB released a decision granting approval of the project's application for a Certificate of Public Convenience and Necessity. The approval contained 264 conditions including the requirement to file an updated cost estimate and report on the decision to construct by the end of 2013 and, further, that construction must commence by December 31, 2015.

Nevertheless, uncertainty persists with respect to the project's ultimate commercial structure and fiscal framework, the timeframes under which the project would proceed and if and when the Company's advances to the APG will be repaid. Accordingly, at December 31, 2010, TransCanada recorded a valuation provision for its $146 million loan to the APG. Future amounts advanced to the APG in furtherance of the MGP will be expensed. TransCanada remains committed to advancing the project. At December 31, 2010, Loans and Advances included nil (2009 – $143 million) for advances to the APG.

NOTE 8 JOINT VENTURE INVESTMENTS

		TransCanada's Proportionate Share				
	Ownership Interest as at December 31,	Income before Income Taxes Year Ended December 31			Net Assets December 31	
(millions of dollars)	2010	**2010**	2009	2008	**2010**	2009
Natural Gas Pipelines						
Northern Border[1]		**69**	47	59	**389**	420
Iroquois	44.5%	**40**	44	32	**181**	183
TQM	50.0%	**16**	22	12	**85**	82
Other	Various	**16**	17	8	**36**	56
Energy						
Bruce A	48.8%	**35**	3	46	**3,011**	2,386
Bruce B	31.6%	**138**	236	136	**505**	585
CrossAlta	60.0%	**45**	55	44	**73**	77
Portlands Energy[2]	50.0%	**33**	24	–	**335**	358
Cartier Wind[3]	62.0%	**24**	26	12	**355**	327
Other	Various	**8**	4	9	**103**	99
		424	478	358	**5,073**	4,573

(1) The results reflect a 50 per cent interest in Northern Border as a result of the Company fully consolidating PipeLines LP. At December 31, 2010, TransCanada had an ownership interest in PipeLines LP of 38.2 per cent (2009 – 38.2 per cent; 2008 – 32.1 per cent) and its effective ownership of Northern Border, net of non-controlling interests, was 19.1 per cent (2009 – 19.1 per cent; 2008 – 16.1 per cent).

(2) Portlands Energy began operating in April 2009.

(3) TransCanada proportionately consolidates its 62 per cent interest in the Cartier Wind assets. Carleton, the third phase of the five-phase Cartier Wind project, began operating in November 2008.

Summarized Financial Information of Joint Ventures

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Income			
Revenues	**1,602**	1,598	1,474
Plant operating costs and other	**(913)**	(856)	(893)
Depreciation and amortization	**(208)**	(196)	(154)
Interest expense and other	**(57)**	(68)	(69)
Proportionate Share of Joint Venture Income before Income Taxes	**424**	478	358

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Cash Flows			
Operating activities	**345**	203	389
Investing activities	**(926)**	(399)	(1,754)
Financing activities[1]	**588**	130	1,353
Effect of foreign exchange rate changes on cash and cash equivalents	**(1)**	(17)	23
Proportionate Share of Increase/(Decrease) in Cash and Cash Equivalents of Joint Ventures	**6**	(83)	11

(1) Financing activities included cash outflows resulting from distributions paid to TransCanada of $239 million in 2010 (2009 – $252 million; 2008 – $287 million) and cash inflows resulting from capital contributions paid by TransCanada of $902 million in 2010 (2009 – $864 million; 2008 – $1,170 million).

December 31 (millions of dollars)	**2010**	2009
Balance Sheet		
Cash and cash equivalents	**104**	98
Other current assets	**438**	552
Plant, property and equipment	**5,704**	5,239
Intangibles and other assets/(deferred amounts), net	**14**	10
Current liabilities	**(387)**	(572)
Long-term debt	**(801)**	(753)
Future income taxes	**1**	(1)
Proportionate Share of Net Assets of Joint Ventures	**5,073**	4,573

NOTE 9 ACQUISITIONS AND DISPOSITIONS

Oil Pipelines

Keystone

In August 2009, TransCanada purchased ConocoPhillips' remaining ownership interest in Keystone of approximately 20 per cent for US$553 million plus the assumption of US$197 million of short-term debt. The acquisition increased TransCanada's ownership interest in Keystone to 100 per cent and was recorded in Plant, Property and Equipment. The purchase price reflected ConocoPhillips' capital contributions to date and included capitalization of interest during construction. TransCanada began fully consolidating Keystone upon acquisition.

In 2008, TransCanada entered into an agreement with ConocoPhillips to increase its equity ownership in Keystone to approximately 80 per cent from 50 per cent, with ConocoPhillips' equity ownership in Keystone being reduced concurrently to approximately 20 per cent from 50 per cent. Pursuant to this agreement in 2008 and prior to August 2009, TransCanada funded 100 per cent of the construction expenditures until the participants' project capital contributions were aligned with their revised ownership interests. In 2009, prior to August, TransCanada funded $1.3 billion of cash calls for Keystone, resulting in the Company acquiring an increase in ownership of approximately 18 per cent for $313 million. In 2008, the Company funded $362 million of cash calls, resulting in an increase in ownership of approximately 12 per cent for $176 million. TransCanada's ownership interest was approximately 80 per cent and 62 per cent in August 2009 and at December 31, 2008, respectively. TransCanada proportionately consolidated the Keystone partnerships prior to August 2009.

During 2008, Keystone purchased pipeline facilities located in Saskatchewan and Manitoba from the Canadian Mainline for use in the construction of the Keystone oil pipeline. The sale was completed in three phases for total proceeds of $67 million, with no gain recognized on the sale.

Natural Gas Pipelines

TC PipeLines, LP

In November 2009, PipeLines LP completed an offering of five million common units at a price of US$38.00 per unit, resulting in net proceeds to PipeLines LP of US$182 million. TransCanada contributed an additional US$3.8 million to maintain its general partnership interest but did not purchase any other units. Upon completion of this offering, the Company's ownership interest in PipeLines LP decreased to 38.2 per cent and the Company recognized a dilution gain of $18 million after tax ($29 million pre-tax).

In July 2009, TransCanada sold North Baja to PipeLines LP. As part of the transaction, TransCanada agreed to amend its general partner incentive distribution rights arrangement with PipeLines LP. TransCanada received aggregate consideration totalling approximately US$395 million from PipeLines LP, including US$200 million in cash and 6,371,680 common units of PipeLines LP. TransCanada recorded no gain or loss as a result of the transaction. TransCanada's ownership in PipeLines LP increased to 42.6 per cent as a result of the transaction. TransCanada's increased ownership in PipeLines LP also resulted in a decrease in Non-Controlling Interests and an increase in Contributed Surplus.

Energy

Ravenswood

In August 2008, TransCanada acquired from National Grid plc 100 per cent of the 2,480 MW Ravenswood power facility for US$2.9 billion. TransCanada began consolidating Ravenswood into its Energy segment after the acquisition date. The purchase price was allocated as follows:

(millions of US dollars)	
Current assets	128
Plant, property and equipment	1,666
Other non-current assets	305
Goodwill	834
Current liabilities	(11)
Other non-current liabilities	(10)
	2,912

The allocation of the purchase price was made using the fair value of the net assets at the date of acquisition. Factors that contributed to goodwill included the opportunity to expand the Energy segment further into the U.S. market and to gain a stronger competitive position in the North American power generation business. The goodwill recognized on the transaction is amortizable for tax purposes.

NOTE 10 LONG-TERM DEBT

Outstanding loan amounts (millions of dollars)	Maturity Dates	2010 Outstanding December 31	2010 Interest Rate[1]	2009 Outstanding December 31	2009 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian dollars	2014 to 2020	**872**	**10.9%**	1,002	10.9%
U.S. dollars (2010 and 2009 – US$600)	2012 to 2021	**595**	**9.5%**	626	9.5%
Medium-Term Notes					
Canadian dollars	2011 to 2039	**4,150**	**6.2%**	4,148	6.2%
Senior Unsecured Notes					
U.S. dollars (2010 – US$8,626; 2009 – US$6,496)[2]	2013 to 2040	**8,490**	**5.7%**	6,727	6.7%
		14,107		12,503	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian dollars	2014 to 2024	**390**	**11.4%**	430	11.5%
U.S. dollars (2010 and 2009 – US$375)	2012 to 2023	**371**	**8.2%**	390	8.2%
Medium-Term Notes					
Canadian dollars	2025 to 2030	**502**	**7.4%**	502	7.4%
U.S. dollars (2010 and 2009 – US$33)	2026	**32**	**7.5%**	34	7.5%
		1,295		1,356	
TRANSCANADA PIPELINE USA LTD.					
Bank Loan					
U.S. dollars (2010 and 2009 – US$700)	2012	**696**	**0.5%**	733	0.5%
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. dollars (2010 – US$432; 2009 – US$443)	2021 to 2025	**429**	**8.9%**	462	9.1%
GAS TRANSMISSION NORTHWEST CORPORATION					
Senior Unsecured Notes					
U.S. dollars (2010 – US$325; 2009 – US$400)	2015 to 2035	**322**	**5.5%**	417	5.4%
TC PIPELINES, LP					
Unsecured Loan					
U.S. dollars (2010 – US$483; 2009 – US$484)	2011	**480**	**0.8%**	506	1.0%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. dollars (2010 – US$392; 2009 – US$411)	2011 to 2030	**389**	**7.8%**	429	7.8%
TUSCARORA GAS TRANSMISSION COMPANY					
Senior Secured Notes					
U.S. dollars (2010 – US$31; 2009 – US$57)	2012 to 2017	**31**	**4.4%**	60	7.3%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes[3]					
U.S. dollars (2010 – US$164; 2009 – US$180)	2018	**161**	**6.1%**	186	6.1%
OTHER					
Senior Notes					
U.S. dollars (2010 and 2009 – US$12)	2011	**12**	**7.3%**	12	7.3%
		17,922		16,664	
Less: Current Portion of Long-Term Debt		**894**		478	
		17,028		16,186	

(1) Interest rates are the effective interest rates except for those pertaining to long-term debt issued for the Company's regulated operations, in which case the weighted average interest rate is presented as required by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates.

(2) Includes fair value adjustments of $8 million (2009 – $6 million) for interest rate swap agreements on US$250 million of debt at December 31, 2010 (2009 – US$250 million).

(3) Senior Secured Notes are secured by shipper transportation contracts, existing and new guarantees, letters of credit and collateral requirements.

Principal Repayments

Principal repayments on the long-term debt of the Company for the next five years are approximately as follows: 2011 – $894 million; 2012 – $1,118 million; 2013 – $894 million; 2014 – $970 million; and 2015 – $1,064 million.

TransCanada PipeLines Limited

In September 2010, TransCanada PipeLines Limited (TCPL) issued US$1.0 billion of Senior Notes maturing October 1, 2020, and bearing interest at 3.80 per cent.

In June 2010, TCPL issued US$500 million and US$750 million of Senior Notes maturing on June 1, 2015 and June 1, 2040, respectively, and bearing interest at 3.40 per cent and 6.10 per cent, respectively.

In February 2010, TCPL retired US$120 million of 6.125 per cent Medium-Term Notes and in August 2010, TCPL retired $130 million of 10.50 per cent debentures.

In October 2009, TCPL retired $250 million of 10.625 per cent debentures.

In February 2009, TCPL issued $300 million and $400 million of Medium-Term Notes maturing in February 2014 and February 2039, respectively, and bearing interest at 5.05 per cent and 8.05 per cent, respectively. Also in February 2009, TCPL retired $200 million of 4.10 per cent Medium-Term Notes.

In January 2009, TCPL issued US$750 million and US$1.25 billion of Senior Unsecured Notes maturing in January 2019 and January 2039, respectively, and bearing interest at 7.125 per cent and 7.625 per cent, respectively. Also in January 2009, TCPL retired US$227 million of 6.49 per cent Medium-Term Notes.

NOVA Gas Transmission Ltd.

Debentures issued by NOVA Gas Transmission Ltd. (NGTL) in the amount of $225 million have retraction provisions that entitle the holders to require redemption of up to eight per cent of the then outstanding principal plus accrued and unpaid interest on specified repayment dates. No redemptions were made to December 31, 2010.

TransCanada PipeLine USA Ltd.

TransCanada PipeLine USA Ltd. (TCPL USA) has a US$1.0 billion committed, unsecured, syndicated credit facility, guaranteed by TransCanada, consisting of a US$700 million five-year term loan maturing in 2012 and a US$300 million revolving facility maturing in February 2013, described further in Note 20. Included in Long-Term Debt was an outstanding balance of US$700 million on the term loan at December 31, 2010 and 2009.

TC PipeLines, LP

PipeLines LP has available a committed, unsecured syndicated senior credit facility consisting of a US$475 million senior term loan and a US$250 million senior revolving credit facility maturing December 2011. At December 31, 2010, US$8 million (2009 – US$9 million) was drawn on the US$250 million senior revolving credit facility. Included in long-term debt were combined draws of US$483 million at December 31, 2010 (2009 – US$484 million).

Interest Expense

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Interest on long-term debt	**1,149**	1,212	970
Interest on junior subordinated notes	**65**	73	68
Interest on short-term debt	**15**	10	32
Capitalized interest	**(587)**	(358)	(141)
Amortization and other financial charges[1]	**59**	17	14
	701	954	943

(1) Amortization and other financial charges includes amortization of transaction costs and debt discounts calculated using the effective interest method and changes in the fair value of derivatives used to manage the Company's exposure to rising interest rates.

The Company made interest payments of $652 million in 2010 (2009 – $916 million; 2008 – $833 million) on long-term debt and junior subordinated notes, net of interest capitalized on construction projects.

NOTE 11 LONG-TERM DEBT OF JOINT VENTURES

		2010		2009	
Outstanding loan amounts (millions of dollars)	Maturity Dates	**Outstanding December 31[1]**	**Interest Rate[2]**	Outstanding December 31[1]	Interest Rate[2]
NORTHERN BORDER PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. dollars (2010 and 2009 – US$175)	2016 to 2021	**174**	**7.1%**	182	7.1%
Bank Facility					
U.S. dollars (2010 – US$96; 2009 – US$108)	2012	**94**	**0.5%**	112	0.5%
IROQUOIS GAS TRANSMISSION SYSTEM, L.P.					
Senior Unsecured Notes					
U.S. dollars (2010 – US$178; 2009 – US$210)	2019 to 2027	**176**	**6.1%**	219	7.8%
BRUCE POWER L.P. AND BRUCE POWER A L.P.					
Capital Lease Obligations	2018	**207**	**7.5%**	222	7.5%
Term Loan	2031	**90**	**7.1%**	93	7.1%
TRANS QUÉBEC & MARITIMES PIPELINE INC.					
Bonds	2014 to 2017	**87**	**4.2%**	125	5.2%
Term Loan	2011	**35**	**1.6%**	10	0.4%
OTHER	2012 to 2015	**3**	**2.7%**	2	2.7%
		866		965	
Less: Current Portion of Long-Term Debt of Joint Ventures		**65**		212	
		801		753	

(1) Amounts outstanding represent TransCanada's proportionate share, except for Northern Border, which reflects a 50 per cent interest as a result of the Company fully consolidating PipeLines LP.

(2) Interest rates are the effective interest rates except for those pertaining to long-term debt issued for TQM's regulated operations, in which case the weighted average interest rate is presented as required by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates. At December 31, 2010, the effective interest rate resulting from swap agreements was nil on the Northern Border bank facility (2009 – 0.5 per cent).

The long-term debt of joint ventures is non-recourse to TransCanada, except that TransCanada has provided certain pro-rata guarantees related to the capital lease obligations of Bruce Power. The security provided with respect to the debt of each joint venture is limited to the rights and assets of the joint venture and does not extend to the rights and assets of TransCanada, except to the extent of TransCanada's investment. TQM has two series of bonds which mature in 2014 and 2017, respectively. The bonds are secured by the pledge of a bond and promissory note of certain affiliated entities. All security interests with respect to the TQM bonds terminate on redemption or repayment of the series of bonds maturing in 2014.

Subject to meeting certain requirements, the Bruce Power capital lease agreements provide for a series of renewals commencing January 1, 2019. The first renewal is for a period of one year and each of 12 renewals thereafter is for a period of two years.

The Company's proportionate share of principal repayments for the next five years resulting from maturities and sinking fund obligations of the non-recourse joint venture debt is approximately as follows: 2011 – $49 million; 2012 – $103 million; 2013 – $7 million; 2014 – $44 million; and 2015 – $7 million.

The Company's proportionate share of principal payments for the next five years resulting from the capital lease obligations of Bruce Power is approximately as follows: 2011 – $16 million; 2012 – $18 million; 2013 – $20 million; 2014 – $22 million; and 2015 – $26 million.

In September 2009, Northern Border retired US$200 million of 7.75 per cent Senior Notes. In August 2009, Northern Border issued US$100 million of Senior Unsecured Notes maturing in August 2016 and bearing interest at 6.24 per cent.

In April 2010, Iroquois retired US$200 million of Series I bonds bearing interest at 9.16 per cent and issued US$150 million of bonds maturing in April 2020 and bearing interest at 4.96 per cent.

In May 2009, Iroquois issued US$140 million of Senior Unsecured Notes maturing in May 2019 and bearing interest at 6.63 per cent.

In September 2010, TQM retired $100 million of 7.53 per cent Series I bonds and $75 million of 3.906 per cent Series J bonds. In July 2010, TQM issued $100 million of bonds maturing in September 2017 and bearing interest at 4.25 per cent.

In September 2009, TQM issued $75 million of bonds maturing in September 2014 and bearing interest at 4.05 per cent. In August 2009, TQM retired $100 million of 6.50 per cent Series H bonds.

Sensitivity

A one per cent change in interest rates would have the following effect on Net Income assuming all other variables were to remain constant:

(millions of dollars)	Increase	Decrease
Effect on interest expense of variable interest rate debt	1	(1)

Interest Expense of Joint Ventures

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Interest on long-term debt	**39**	51	45
Interest on capital lease obligations	**16**	17	18
Short-term interest and other financial charges	**4**	(4)	9
	59	64	72

The Company's proportionate share of the interest payments by joint ventures was $42 million in 2010 (2009 – $41 million; 2008 – $50 million), net of interest capitalized on construction projects.

The Company's proportionate share of interest payments from the capital lease obligations of Bruce Power was $16 million in 2010 (2009 – $17 million; 2008 – $18 million).

NOTE 12 JUNIOR SUBORDINATED NOTES

		2010		2009	
Outstanding loan amount (millions of dollars)	Maturity Date	**Outstanding December 31**	**Effective Interest Rate**	Outstanding December 31	Effective Interest Rate
TRANSCANADA PIPELINES LIMITED					
U.S. dollars (2010 and 2009 – US$1,000)	2017	**985**	**6.5%**	1,036	6.5%

Junior Subordinated Notes of US$1.0 billion mature in 2067 and bear interest at 6.35 per cent per year until May 15, 2017, when interest will convert to a floating rate that is reset quarterly to the three-month London Interbank Offered Rate plus 221 basis points. The Company has the option to defer payment of interest for periods of up to 10 years without giving rise to a default and without permitting acceleration of payment under the terms of the Junior Subordinated Notes. However, the Company would be prohibited from paying dividends during any such deferral period. The Junior Subordinated Notes are subordinated in right of payment to existing and future senior indebtedness and are effectively subordinated to all indebtedness and other obligations of TCPL. The Junior Subordinated Notes are callable at the Company's option at any time on or after May 15, 2017, at 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption. The Junior Subordinated Notes are callable earlier, in whole or in part, upon the occurrence of certain events and at the Company's option at an amount equal to the greater of 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption and an amount determined by a specified formula in accordance with the terms of the Junior Subordinated Notes.

NOTE 13 DEFERRED AMOUNTS

December 31 (millions of dollars)	**2010**	2009
Fair value of derivative contracts (Note 18)	**282**	272
Employee benefit plans (Note 22)	**251**	235
Asset retirement obligations (Note 21)	**65**	110
Other	**96**	126
	694	743

NOTE 14 RATE-REGULATED BUSINESSES

TransCanada's businesses that apply RRA currently include Canadian and U.S. natural gas pipelines and regulated U.S. natural gas storage. Regulatory assets and liabilities represent future revenues that are expected to be recovered from or refunded to customers based on decisions and approvals by the applicable regulatory authorities. In addition to Canadian GAAP financial reporting, TransCanada's regulated natural gas pipelines file financial reports using accounting regulations required by their respective regulators.

Canadian Regulated Operations

Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and return on capital as approved by the applicable regulatory authorities.

Rates charged by TransCanada's Canadian regulated pipelines are typically set through a process that involves filing an application with the regulators for a change in rates. Regulated rates are underpinned by the total annual revenue requirement, which comprises a specified annual return on capital, including debt and equity, and all necessary operating expenses, taxes and depreciation.

TransCanada's Canadian regulated natural gas pipelines have generally been subject to a cost-of-service model wherein forecasted costs, including a return on capital, determine the revenues for the upcoming year. To the extent that actual costs and revenues are more or less than the forecasted costs and revenues, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Differences between actual and forecasted costs that the regulator does not allow to be deferred are included in the determination of net income in the year they are incurred.

The Canadian Mainline, Alberta System, Foothills and TQM pipelines are regulated by the NEB under the *National Energy Board Act* (Canada). In April 2009, the NEB determined that the Alberta System was within federal jurisdiction and would be subject to NEB regulation. Prior to

April 2009, the Alberta System was regulated by the AUC. The NEB regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's Canadian regulated natural gas transmission systems.

In October 2009, the NEB issued a decision that its RH-2-94 Decision, which established a rate of return on common equity (ROE) formula that had formed the basis of determining tolls for natural gas pipelines under NEB jurisdiction since 1995, would no longer be in effect. The decision meant a company's cost of capital will now be determined by negotiations between pipeline companies and their shippers or by the NEB if a pipeline company files a cost of capital application. The decision has affected TransCanada's NEB regulated pipelines. However, the Canadian Mainline continues to base its return on the RH-2-94 NEB ROE formula in accordance with the terms of the current Canadian Mainline tolls settlement, described below.

Canadian Mainline

The Canadian Mainline currently operates under a five-year tolls settlement, which is effective January 1, 2007 to December 31, 2011. The Canadian Mainline's cost of capital for establishing tolls under the settlement reflects ROE as determined by the NEB's RH-2-94 ROE formula on a deemed common equity of 40 per cent. The allowed ROE in 2010 for the Canadian Mainline was 8.52 per cent (2009 – 8.57 per cent). The balance of the capital structure is comprised of short- and long-term debt.

The settlement also established the Canadian Mainline's fixed operating, maintenance and administration (OM&A) costs for each of the five years. Variances between actual OM&A costs and those agreed to in the settlement accrued fully to TransCanada from 2007 to 2009. Variances in OM&A costs were shared equally between TransCanada and its customers in 2010 and 2011. All other cost elements of the revenue requirement are treated on a flow-through basis. The settlement also allows performance-based incentive arrangements. In 2009, the NEB approved an adjustment charge account, which was established to reduce tolls in 2010 under a settlement with stakeholders. In accordance with the terms of the settlement, balances in the adjustment charge account are to be amortized at the composite depreciation rate and included in tolls beginning in 2011.

Alberta System

In September 2010, the NEB approved the Alberta System's 2010 – 2012 Revenue Requirement Settlement Application. The settlement provides for a 9.70 per cent ROE on a deemed common equity of 40 per cent and fixes certain annual OM&A costs during the term. Any variances between actual costs and those agreed to in the settlement accrue to TransCanada. All other costs are treated on a flow-through basis. In 2009, the Alberta System operated under the 2008 – 2009 Revenue Requirement Settlement which established fixed amounts for ROE, income taxes and certain OM&A costs.

Foothills

In June 2010, TransCanada reached an agreement to establish a cost of capital for Foothills that reflects a 9.70 per cent ROE on a deemed common equity of 40 per cent for 2010 to 2012. In 2009, the ROE for Foothills was 8.57 per cent on a deemed common equity of 36 per cent based on the NEB's RH-2-94 ROE formula. A component of OM&A costs is fixed, subject to the terms of the B.C. System/Foothills Integration Settlement, and variances between actual and fixed amounts are shared with customers.

TQM

In June 2010, the NEB approved TQM's final 2009 tolls consisting of a 6.4 per cent after-tax weighted average cost of capital return on rate base and all the cost components addressed in a three-year partial settlement for the years 2007 to 2009, as approved by the NEB in September 2008. In November 2010, the NEB approved TQM's multi-year settlement with its interested parties regarding its annual revenue requirements for 2010, 2011 and 2012. As part of the settlement, the annual revenue requirement comprises fixed and flow-through components. The fixed component includes certain OM&A costs, return on rate base, depreciation, and municipal taxes. Any variances between actual costs and those included in the fixed component accrue to TQM.

U.S. Regulated Operations

TransCanada's U.S. natural gas pipelines are "natural gas companies" operating under the provisions of the *Natural Gas Act of 1938,* the *Natural Gas Policy Act of 1978* and the *Energy Policy Act of 2005*, and are subject to the jurisdiction of the FERC. The *Natural Gas Act of 1938* grants the FERC authority over the construction and operation of pipelines and related facilities. The FERC also has authority to regulate rates for natural gas transportation in interstate commerce.

ANR

ANR's natural gas storage and transportation services are regulated by the FERC and operate in accordance with FERC-approved tariffs. These tariffs include maximum and minimum rates for services and permit ANR to discount or negotiate rates on a non-discriminatory basis. ANR Pipeline Company rates were established pursuant to a settlement approved by the FERC and effective in 1997. ANR Storage Company's rates were established pursuant to a settlement approved by the FERC and effective in 1990. None of ANR's FERC-regulated operations are required to file for new rates at any time in the future, nor are any of the operations prohibited from filing a case for new rates.

GTN

GTN is regulated by the FERC and operates in accordance with a FERC-approved tariff that establishes maximum and minimum rates for various services. GTN is permitted to discount or negotiate these rates on a non-discriminatory basis. GTN's rates were established pursuant to a settlement approved by the FERC in January 2008. Under the settlement, a five-year moratorium was established during which GTN and the settling parties are prohibited from taking certain actions under the *Natural Gas Act of 1938*, including any filings to adjust rates. The settlement requires GTN to file a rate case within seven years of the effective date.

Great Lakes

Great Lakes is regulated by the FERC and operates in accordance with a FERC-approved tariff that establishes maximum and minimum rates for its various services and permits Great Lakes to discount or negotiate rates on a non-discriminatory basis. In November 2009, the FERC initiated an investigation to determine whether Great Lakes' rates were just and reasonable. In July 2010, the FERC approved a settlement stipulation and agreement filed by Great Lakes that applies to all current and future shippers. The settlement rates were effective May 1, 2010 and will remain in effect until at least November 30, 2011. The settlement includes a moratorium on participants and customers from filing a rate case to place new rates into effect prior to November 1, 2012. There is also a moratorium on Great Lakes from filing a rate case prior to June 1, 2011 to place new rates into effect prior to December 1, 2011.

Regulatory Assets and Liabilities

Year ended December 31 (millions of dollars)	**2010**	2009	Remaining Recovery/ Settlement Period
			(years)
Regulatory Assets			
Future income taxes[1]	**1,256**	1,305	n/a
Operating and debt-service regulatory assets[2]	**237**	221	1
Adjustment charge[3]	**85**	–	32
Other[4]	**174**	219	n/a
	1,752	1,745	
Less: Current portion included in Other Current Assets	**240**	221	
	1,512	1,524	
Regulatory Liabilities			
Foreign exchange on long-term debt[5]	**200**	218	1 - 19
Operating and debt-service regulatory liabilities[2]	**98**	31	1
Other[4]	**150**	167	n/a
	448	416	
Less: Current portion included in Accounts Payable	**134**	31	
	314	385	

(1) These regulatory assets are underpinned by non-cash transactions or are recovered without an allowance for return as approved by the regulator. Accordingly, these regulatory assets are not included in rate base and do not yield a return on investment during the recovery period.

(2) Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determining tolls for the following calendar year. Pre-tax operating results in 2010 would have been $51 million higher (2009 – $424 million lower) had these amounts not been recorded as regulatory assets and liabilities.

(3) A regulatory adjustment account of $85 million was established and agreed upon by Canadian Mainline stakeholders to reduce tolls in 2010. The adjustment account will be amortized at the composite depreciation rate commencing in 2011.

(4) Pre-tax operating results in 2010 would have been $28 million higher (2009 – $82 million lower) had these amounts had not been recorded as regulatory assets and liabilities.

(5) Foreign exchange on long-term debt of the Canadian Mainline, Alberta System and Foothills represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate at the time of issue. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls. In the absence of RRA, Canadian GAAP would have required the inclusion of these unrealized gains or losses in Net Income.

NOTE 15 NON-CONTROLLING INTERESTS

The Company's non-controlling interests included in the Consolidated Balance Sheet were as follows:

December 31 (millions of dollars)	**2010**	2009
Non-controlling interest in PipeLines LP[(1)]	**686**	705
Preferred shares of subsidiary	**389**	389
Non-controlling interest in Portland	**82**	80
	1,157	1,174

The Company's non-controlling interests included in the Consolidated Income Statement were as follows:

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Non-controlling interest in PipeLines LP[(1)]	**87**	66	62
Preferred share dividends of subsidiary	**22**	22	22
Non-controlling interest in Portland	**6**	8	46
	115	96	130

(1) Effective November 18, 2009, the non-controlling interest in PipeLines LP was 61.8 per cent (July 1, 2009 to November 17, 2009 – 57.4 per cent; February 22, 2007 to June 30, 2009 – 67.9 per cent).

The non-controlling interests in PipeLines LP and Portland as at December 31, 2010 represented the 61.8 per cent and 38.3 per cent interest, respectively, not owned by TransCanada (2009 – 61.8 per cent and 38.3 per cent, respectively; 2008 – 67.9 per cent and 38.3 per cent, respectively).

In 2010, TransCanada received fees of $2 million from PipeLines LP (2009 and 2008 – $2 million) and $7 million from Portland (2009 – $8 million; 2008 – $7 million) for services provided.

Preferred Shares of Subsidiary

December 31	Number of Shares	Dividend Rate per Share	Redemption Price per Share	**2010**	2009
	(thousands)			(millions of dollars)	(millions of dollars)
Cumulative First Preferred Shares of Subsidiary					
Series U	4,000	$2.80	$50.00	**195**	195
Series Y	4,000	$2.80	$50.00	**194**	194
				389	389

The authorized number of preferred shares of TCPL issuable in each series is unlimited. All of the cumulative first preferred shares of TCPL are without par value.

On or after October 15, 2013, TCPL may redeem the Series U preferred shares at $50 per share, and on or after March 5, 2014, TCPL may redeem the Series Y shares at $50 per share.

Cash Dividends
Cash dividends of $22 million or $2.80 per share were paid on the Series U and Series Y preferred shares in each of 2010, 2009 and 2008.

NOTE 16 COMMON SHARES

	Number of Shares	Amount
	(thousands)	(millions of dollars)
Outstanding at January 1, 2008	539,765	6,662
Issuance of common shares[1]	69,805	2,363
Dividend reinvestment and share purchase plan	5,976	218
Exercise of options	925	21
Outstanding at December 31, 2008	616,471	9,264
Issuance of common shares[1]	58,420	1,792
Dividend reinvestment and share purchase plan	8,220	254
Exercise of options	1,248	28
Outstanding at December 31, 2009	684,359	11,338
Dividend reinvestment and share purchase plan	**10,670**	**378**
Exercise of options	**1,201**	**29**
Outstanding at December 31, 2010	**696,230**	**11,745**

(1) Net of underwriting commissions and future income taxes.

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

In June 2009, TransCanada completed a public offering of 58.4 million common shares at a purchase price of $31.50 per share. The issue, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.8 billion.

In fourth quarter 2008, TransCanada completed a public offering of 35.1 million common shares at a purchase price of $33.00 per share. The issue, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.2 billion.

In May 2008, TransCanada completed a public offering of 34.7 million common shares at a purchase price of $36.50 per share. The issue, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.3 billion.

Net Income per Share

Net income per share is calculated by dividing Net Income Applicable to Common Shares by the weighted average number of common shares. During the year, the weighted average number of common shares of 690.5 million and 691.7 million (2009 – 651.8 million and 652.8 million; 2008 – 569.6 million and 571.5 million) were used to calculate basic and diluted earnings per share, respectively. The increase in the weighted average number of shares for the diluted earnings per share calculation is due to the options exercisable under TransCanada's Stock Option Plan.

Stock Options

	Number of Options	Weighted Average Exercise Prices	Options Exercisable
	(thousands)		(thousands)
Outstanding at January 1, 2008	8,609	$27.32	6,118
Granted	872	$39.75	
Exercised	(925)	$22.26	
Forfeited	(55)	$35.23	
Outstanding at December 31, 2008	8,501	$29.10	6,461
Granted	1,191	$31.96	
Exercised	(1,248)	$21.22	
Forfeited	(170)	$35.58	
Outstanding at December 31, 2009	8,274	$30.56	6,212
Granted	**1,367**	**$35.32**	
Exercised	**(1,201)**	**$22.04**	
Forfeited	**(34)**	**$27.35**	
Outstanding at December 31, 2010	**8,406**	**$32.57**	**6,458**

Stock options outstanding were as follows:

December 31, 2010	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
	(thousands)		(years)	(thousands)		(years)
$18.01 to $21.43	**1,086**	**$20.54**	**1.1**	**1,086**	**$20.54**	**1.1**
$26.85 to $31.93	**1,387**	**$29.06**	**2.8**	**1,316**	**$28.91**	**1.9**
$31.97 to $33.08	**1,677**	**$32.37**	**4.6**	**1,126**	**$32.57**	**4.2**
$35.08	**1,145**	**$35.08**	**6.2**	**244**	**$35.08**	**6.2**
$35.23	**1,001**	**$35.23**	**2.2**	**1,001**	**$35.23**	**2.2**
$36.26 to $38.10	**1,163**	**$37.80**	**4.3**	**941**	**$38.10**	**3.1**
$38.14 to $39.75	**947**	**$39.58**	**4.1**	**744**	**$39.54**	**4.1**
	8,406	**$32.57**	**3.2**	**6,458**	**$31.92**	**2.5**

An additional 5.3 million common shares were reserved for future issuance under TransCanada's Stock Option Plan at December 31, 2010. The weighted average fair value of options granted to purchase common shares under the Company's Stock Option Plan was determined to be $5.76 for the year ended December 31, 2010 (2009 – $4.78; 2008 – $3.97). The Company used the Black-Scholes model for determining the fair value of options granted applying the following weighted average assumptions for 2010: four years of expected life (2009 and 2008 – four years); 2.0 per cent interest rate (2009 – 1.7 per cent; 2008 – 3.5 per cent); 27 per cent volatility (2009 – 29 per cent; 2008 – 16 per cent); and 4.7 per cent dividend yield (2009 – 5.2 per cent; 2008 – 4.0 per cent). The amount expensed for stock options, with a corresponding increase in contributed surplus, was $4 million in 2010 (2009 and 2008 – $4 million).

The total intrinsic value of options exercised in 2010 was $17 million (2009 and 2008 – $15 million). As at December 31, 2010, the aggregate intrinsic value of the total options exercisable was $40 million and the total intrinsic value of options outstanding was $47 million. In 2010, the 1.5 million (2009 – 1.2 million; 2008 – 1.4 million) shares that vested had a fair value of $57 million (2009 – $43 million; 2008 – $45 million).

Shareholder Rights Plan

TransCanada's Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Under certain circumstances, each common share is entitled to one right that entitles certain holders to purchase two common shares of the Company for the price of one.

Cash Dividends

Cash dividends of $710 million, net of the Dividend Reinvestment and Share Purchase Plan (DRP), or $1.58 per common share were paid in 2010 (2009 – $722 million or $1.50 per common share; 2008 – $577 million or $1.42 per common share).

Dividend Reinvestment and Share Purchase Plan

TransCanada's Board of Directors has authorized the issuance of common shares from treasury at a discount to participants in the Company's DRP. Under this plan, eligible holders of common or preferred shares of TransCanada and preferred shares of TCPL may reinvest their dividends and make optional cash payments to obtain TransCanada common shares. The DRP shares are provided to the participants at a discount to the average market price in the five days before dividend payment. The discount was set at three per cent in 2009 and 2010, and was reduced to two per cent commencing with the dividends declared in February 2011. The discount was set at two per cent for 2008 and was increased to three per cent commencing with the dividends declared in February 2009. The Company reserves the right to alter the discount or to satisfy its DRP obligations by instead purchasing shares on the open market at any time. In 2010, dividends of $378 million were paid (2009 – $254 million; 2008 – $218 million) through the issuance of 10.7 million (2009 – 8.2 million; 2008 – 6.0 million) common shares from treasury in accordance with the DRP.

NOTE 17 PREFERRED SHARES

December 31	Number of Shares Authorized and Outstanding	Dividend Rate per Share	Redemption Price per Share	**2010**	2009
	(thousands)			(millions of dollars)[1]	(millions of dollars)[1]
Cumulative First Preferred Shares					
Series 1	22,000	$1.15	$25.00	**539**	539
Series 3	14,000	$1.00	$25.00	**343**	–
Series 5	14,000	$1.10	$25.00	**342**	–
				1,224	539

(1) Net of underwriting commissions and future income taxes.

In June 2010, TransCanada completed a public offering of 14 million Series 5 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares. The preferred shares were issued at a price of $25 per share, resulting in gross proceeds of $350 million including the underwriters' option. The holders of the Series 5 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.10 per share, payable quarterly, yielding 4.4 per cent per annum for the initial five-and-a-half-year period ending January 30, 2016. The dividend rate will reset on January 30, 2016 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 1.54 per cent. The Series 5 preferred shares are redeemable by TransCanada on January 30, 2016 and on January 30 of every fifth year thereafter at a price of $25 per share plus all accrued and unpaid dividends.

The Series 5 preferred shareholders have the right to convert their shares into Series 6 cumulative redeemable first preferred shares on January 30, 2016 and on January 30 of every fifth year thereafter. The holders of Series 6 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.54 per cent.

In March 2010, TransCanada completed a public offering of 14 million Series 3 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares. The preferred shares were issued at a price of $25 per share, resulting in gross proceeds of $350 million including the underwriters' option. The holders of the Series 3 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.00 per share, payable quarterly, yielding 4.0 per cent per annum for the initial five-year period ending June 30, 2015. The dividend rate will reset on June 30, 2015 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 1.28 per cent. The Series 3 preferred shares are redeemable by TransCanada on June 30, 2015 and on June 30 of every fifth year thereafter at a price of $25 per share plus all accrued and unpaid dividends.

The Series 3 preferred shareholders have the right to convert their shares into Series 4 cumulative redeemable first preferred shares on June 30, 2015 and on June 30 of every fifth year thereafter. The holders of Series 4 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.28 per cent.

In September 2009, TransCanada completed a public offering of 22 million Series 1 cumulative redeemable first preferred shares for gross proceeds of $550 million. The holders of the Series 1 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.15 per share, payable quarterly, yielding 4.6 per cent per annum for the initial five-year period ending December 31, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield plus 1.92 per cent. The preferred shares are redeemable by TransCanada on or after December 31, 2014 at a price of $25 per share plus all accrued and unpaid dividends.

The Series 1 preferred shareholders have the right to convert their shares into Series 2 cumulative redeemable first preferred shares on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.92 per cent.

The preferred shareholders are eligible to participate in the Company's DRP.

Cash Dividends

In 2010, the Company made cash dividend payments of $24 million, net of DRP, or $1.15 per Series 1 preferred share (2009 – $6 million or $0.2875 per share), $11 million, net of DRP, or $0.8041 per Series 3 preferred share and $9 million, net of DRP, or $0.3707 per Series 5 preferred share.

NOTE 18 RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TransCanada has exposure to market risk, counterparty credit risk and liquidity risk. TransCanada engages in risk management activities with the objective of protecting earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TransCanada's risks and related exposures are in line with the Company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by risk management and internal audit personnel. The Board of Directors' Audit Committee oversees how management monitors compliance with risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of risk management controls and procedures, the results of which are reported to the Audit Committee.

Market Risk

The Company constructs and invests in large infrastructure projects, purchases and sells energy commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. These activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which affect the Company's earnings and the value of the financial instruments it holds.

The Company uses derivatives as part of its overall risk management strategy to manage the exposure to market risk that results from these activities. Derivative contracts used to manage market risk generally consist of the following:

- Forwards and futures contracts – contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TransCanada enters into foreign exchange and commodity forwards and futures to mitigate the impact of volatility in foreign exchange rates and commodity prices.
- Swaps – contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.
- Options – contractual agreements to convey the right, but not the obligation, of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.

Where possible, derivative financial instruments are designated as hedges, but in some cases derivatives do not meet the specific criteria for hedge accounting treatment and are accounted for at fair value with changes in fair value recorded in Net Income in the period of change. This may expose the Company to increased variability in reported operating results because the fair value of the derivative instruments can fluctuate significantly from period to period. However, the Company enters into the arrangements as they are considered to be effective economic hedges.

Commodity Price Risk
The Company is exposed to commodity price movements as part of its normal business operations, particularly in relation to the prices of electricity, natural gas and oil products. A number of strategies are used to mitigate these exposures, including the following:

- Subject to its overall risk management strategy, the Company commits a portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to mitigate price risk in its asset portfolio.
- The Company purchases a portion of the natural gas and oil products required for its power plants or enters into contracts that base the sale price of electricity on the cost of natural gas, effectively locking in a margin. A significant portion of the electricity needed to fulfil the Company's power sales commitments is fulfilled through power generation or purchased through contracts, thereby reducing the Company's exposure to fluctuating commodity prices.
- The Company enters into offsetting or back-to-back positions using derivative financial instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

The Company assesses its commodity contracts and derivative instruments used to manage commodity risk to determine the appropriate accounting treatment. Contracts, with the exception of leases, have been assessed to determine whether they or certain aspects of them meet the definition of a derivative. Certain commodity purchase and sale contracts are derivatives but fair value accounting is not required, as they were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected purchase, sale or usage requirements and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain exemptions.

Natural Gas Storage Commodity Price Risk
TransCanada manages its exposure to seasonal natural gas price spreads in its non-regulated Natural Gas Storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TransCanada simultaneously enters 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 natural gas price movements. Fair value adjustments recorded each period on proprietary natural gas inventory in storage and on these forward contracts are not representative of the amounts that will be realized on settlement.

At December 31, 2010, the fair value of proprietary natural gas inventory in storage, measured using a weighted average of forward prices for the following four months less selling costs, was $49 million (2009 – $73 million). The change in fair value of proprietary natural gas inventory in storage in 2010 resulted in pre-tax unrealized losses of $16 million (2009 – gains of $3 million; 2008 – losses of $7 million), which were recorded as a decrease to Revenues and to Inventories. The change in fair value of natural gas forward purchase and sales contracts in 2010 resulted in pre-tax unrealized gains of $6 million (2009 – losses of $2 million; 2008 – gains of $7 million), which were recorded as an increase to Revenues and to Inventories.

Foreign Exchange and Interest Rate Risk
Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and market interest rates.

A portion of TransCanada's earnings from its Natural Gas Pipelines and Energy segments is generated in U.S. dollars and, therefore, fluctuations in the value of the Canadian dollar relative to the U.S. dollar can affect TransCanada's net income. This foreign exchange impact is partially offset by U.S. dollar-denominated financing costs and by the Company's hedging activities. TransCanada has a greater exposure to U.S. currency fluctuations than in prior years due to growth in its U.S. operations, partially offset by increased levels of U.S. dollar-denominated interest expense.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to its debt and other U.S. dollar-denominated transactions, and to manage the foreign exchange rate exposures of the Alberta System and Foothills operations. Certain of the realized gains and losses on these derivatives are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers in accordance with the terms of the shipping agreements.

TransCanada has floating interest rate debt which subjects it to interest rate cash flow risk. The Company uses a combination of interest rate swaps and options to manage its exposure to this risk.

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 December 31, 2010, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $9.8 billion (US$9.8 billion) (2009 – $7.9 billion (US$7.6 billion)) and a fair value of $11.3 billion (US$11.4 billion) (2009 – $9.8 billion (US$9.3 billion)). At December 31, 2010, $181 million was included in Intangibles and Other Assets (2009 – $96 million) for the fair value of the forwards, swaps and options used to hedge the Company's net U.S. dollar investment in foreign operations.

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

Asset/(Liability) *December 31 (millions of dollars)*	**2010** **Fair Value**[(1)]	**2010** **Notional or Principal Amount**	2009 Fair Value[(1)]	2009 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2011 to 2016)	**179**	**US 2,800**	86	US 1,850
U.S. dollar forward foreign exchange contracts (maturing 2011)	**2**	**US 100**	9	US 765
U.S. dollar options (matured in 2010)	**–**	**–**	1	US 100
	181	**US 2,900**	96	US 2,715

(1) Fair values equal carrying values.

VaR Analysis

TransCanada uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its liquid open positions. VaR represents the potential change in pre-tax earnings over a given holding period for a specified confidence level. The VaR number used by TransCanada is calculated assuming a 95 per cent confidence level that the daily change resulting from normal market fluctuations in its liquid open positions will not exceed the reported VaR. The VaR methodology is a statistically calculated, probability-based approach that takes into consideration market volatilities as well as risk diversification by recognizing offsetting positions and correlations among products and markets. Risks are measured across all products and markets, and risk measures are aggregated to arrive at a single VaR number.

There is currently no uniform industry methodology for estimating VaR. The use of VaR has limitations because it is based on historical correlations and volatilities in commodity prices, interest rates and foreign exchange rates, and assumes that future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR.

TransCanada's estimation of VaR includes wholly owned subsidiaries and incorporates relevant risks associated with each market or business unit. The calculation does not include the regulated natural gas pipelines, as the nature of the rate-regulated pipeline business reduces the impact of market risks. TransCanada's Board of Directors has established a VaR limit, which is monitored on an ongoing basis as part of the Company's risk management policy. TransCanada's consolidated VaR was $12 million at December 31, 2010 (2009 – $12 million).

Counterparty Credit Risk

Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of its contracts with the Company.

Counterparty credit risk is managed through established credit management techniques, including conducting financial and other assessments to establish and monitor a counterparty's creditworthiness, setting exposure limits, monitoring exposures against these limits, using master netting arrangements and obtaining financial assurances where warranted. In general, financial assurances include guarantees, letters of credit and cash. The Company monitors and manages its concentration of counterparty credit risk on an ongoing basis. The Company believes these measures minimize its counterparty credit risk but there is no certainty that they will protect it against all material losses.

TransCanada's maximum counterparty credit exposure with respect to financial instruments at the Balance Sheet date, without taking into account security held, consisted of accounts receivable, the fair value of derivative assets and notes, loans and advances receivable. The carrying amounts and fair values of these financial assets, except amounts for derivative assets, are included in Accounts Receivable and Other in the Non-Derivative Financial Instruments Summary table located in the Fair Values section of this note. 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 that are investment grade. At December 31, 2010, there were no significant amounts past due or impaired.

At December 31, 2010, the Company had a credit risk concentration of $317 million (2009 – $334 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.

TransCanada has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, critical liquidity in the foreign exchange derivative, interest rate derivative and energy wholesale markets, and letters of credit to mitigate TransCanada's exposure to non-creditworthy counterparties.

As a level of uncertainty continues to exist in the global financial markets, TransCanada continues to closely monitor and reassess the creditworthiness of its counterparties. This has resulted in TransCanada reducing or mitigating its exposure to certain counterparties where it was deemed warranted and permitted under contractual terms. As part of its ongoing operations, TransCanada must balance its market and counterparty credit risks when making business decisions.

Calpine Corporation (Calpine) and certain of its subsidaries filed for bankruptcy protection in Canada or the U.S. in 2005. Gas Transmission Northwest Corporation (GTNC) and Portland reached agreements with Calpine for allowed unsecured claims in the Calpine bankruptcy. In February 2008, GTNC and Portland received initial distributions of 9.4 million common shares and 6.1 million common shares, respectively, of Calpine, which represented approximately 85 per cent of their agreed-upon claims. In 2008, these shares were sold into the open market and resulted in total pre-tax gains of $279 million. Claims by NGTL and Foothills Pipe Lines (South B.C.) Ltd. for $32 million and $44 million, respectively, were received in cash in January 2008 and were passed onto shippers on these systems in 2008 and 2009. In 2010, the Company accrued an additional pre-tax gain of $15 million related to expected future proceeds with respect to the GTNC and Portland claims.

Liquidity Risk

Liquidity risk is the risk that TransCanada will not be able to meet its financial obligations as they become due. The Company's approach to managing liquidity risk is to ensure that sufficient cash and credit facilities are available to meet its operating, financing and capital expenditure obligations when due, under both normal and stressed economic conditions.

Management continuously forecasts cash flows for a period of 12 months to identify financing requirements. These requirements are then managed through a combination of committed and demand credit facilities and access to capital markets, as discussed in the Capital Management section of this note.

At December 31, 2010, the Company had unutilized committed revolving bank lines of US$1.0 billion, $2.0 billion and US$0.8 billion maturing in November 2011, December 2012 and December 2012, respectively. The Company has also maintained continuous access to the Canadian commercial paper market on competitive terms.

Capital Management

The primary objective of capital management is to ensure TransCanada has strong credit ratings to support its businesses and maximize shareholder value. In 2010, the overall objective and policy for managing capital remained unchanged from the prior year.

TransCanada manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. The Company's management considers its capital structure to consist of net debt, Non-Controlling Interests and Shareholders' Equity. Net debt comprises Notes Payable, Long-Term Debt and Junior Subordinated Notes less Cash and Cash Equivalents. Net debt only includes obligations that the Company controls and manages. Consequently, it does not include Cash and Cash Equivalents, Notes Payable and Long-Term Debt of TransCanada's joint ventures.

The total capital managed by the Company was as follows:

December 31 (millions of dollars)	**2010**	2009
Notes payable	**2,081**	1,678
Long-term debt	**17,922**	16,664
Junior subordinated notes	**985**	1,036
Cash and cash equivalents	**(660)**	(896)
Net debt	**20,328**	18,482
Non-controlling interests	**1,157**	1,174
Shareholders' equity	**16,727**	15,759
Total equity	**17,884**	16,933
	38,212	35,415

Fair Values

Certain financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Intangibles and Other Assets, Notes Payable, Accounts Payable, Accrued Interest and Deferred Amounts have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. The fair value of foreign exchange and interest rate derivatives has been calculated using year-end market rates and applying a discounted cash flow valuation model. The fair value of power, natural gas and oil products derivatives, and of available-for-sale investments, has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used.

The fair value of the Company's Notes Receivable is calculated by discounting future payments of interest and principal using forward interest rates. Long-Term Debt was estimated based on quoted market prices for the same or similar debt instruments. Credit risk has been taken into consideration when calculating the fair value of derivatives, Notes Receivable and Long-Term Debt.

Non-Derivative Financial Instruments Summary
The carrying and fair values of non-derivative financial instruments were as follows:

	2010		2009	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial Assets[1]				
Cash and cash equivalents	**764**	**764**	997	997
Accounts receivable and other[2][3]	**1,555**	**1,595**	1,432	1,483
Available-for-sale assets[2]	**20**	**20**	23	23
	2,339	**2,379**	2,452	2,503
Financial Liabilities[1][3]				
Notes payable	**2,092**	**2,092**	1,687	1,687
Accounts payable and deferred amounts[4]	**1,436**	**1,436**	1,538	1,538
Accrued interest	**367**	**367**	377	377
Long-term debt	**17,922**	**21,523**	16,664	19,377
Junior subordinated notes	**985**	**992**	1,036	976
Long-term debt of joint ventures	**866**	**971**	965	1,025
	23,668	**27,381**	22,267	24,980

(1) Consolidated Net Income in 2010 included gains of $8 million (2009 – gains of $6 million) for fair value adjustments related to interest rate swap agreements on US$250 million (2009 – US$250 million) of long-term debt. There were no other unrealized gains or losses from fair value adjustments to the financial instruments.

(2) At December 31, 2010, the Consolidated Balance Sheet included financial assets of $1,271 million (2009 – $966 million) in Accounts Receivable, $40 million (2009 – nil) in Other Current Assets and $264 million (2009 – $489 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost except for $250 million (2009 – $250 million) of Long-Term Debt, which is adjusted to fair value.

(4) At December 31, 2010, the Consolidated Balance Sheet included financial liabilities of $1,406 million (2009 – $1,513 million) in Accounts Payable and $30 million (2009 – $25 million) in Deferred Amounts.

The following tables detail the remaining contractual maturities for TransCanada's non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2010:

Contractual Repayments of Financial Liabilities[1]

		Payments Due by Period			
(millions of dollars)	Total	2011	2012 and 2013	2014 and 2015	2016 and Thereafter
Notes payable	2,092	2,092	–	–	–
Long-term debt	17,922	894	2,012	2,034	12,982
Junior subordinated notes	985	–	–	–	985
Long-term debt of joint ventures	866	65	148	99	554
	21,865	3,051	2,160	2,133	14,521

(1) The anticipated timing of settlement of derivative contracts is presented in the Derivatives Financial Instrument Summary in this note.

Interest Payments on Financial Liabilities

		Payments Due by Period			
(millions of dollars)	Total	2011	2012 and 2013	2014 and 2015	2016 and Thereafter
Long-term debt	16,721	1,140	2,190	1,973	11,418
Junior subordinated notes	410	63	126	126	95
Long-term debt of joint ventures	381	48	90	80	163
	17,512	1,251	2,406	2,179	11,676

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2010 is as follows:

	2010			
December 31 *(all amounts in millions unless otherwise indicated)*	**Power**	**Natural Gas**	**Foreign Exchange**	**Interest**
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	**$169**	**$144**	**$8**	**$20**
Liabilities	**$(129)**	**$(173)**	**$(14)**	**$(21)**
Notional Values				
Volumes[3]				
Purchases	**15,610**	**158**	**–**	**–**
Sales	**18,114**	**96**	**–**	**–**
Canadian dollars	**–**	**–**	**–**	**736**
U.S. dollars	**–**	**–**	**US 1,479**	**US 250**
Cross-currency	**–**	**–**	**47/US 37**	**–**
Net unrealized (losses)/gains in the year[4]	**$(32)**	**$27**	**$4**	**$43**
Net realized gains/(losses) in the year[4]	**$77**	**$(42)**	**$36**	**$(74)**
Maturity dates	**2011-2015**	**2011-2015**	**2011-2012**	**2011-2016**
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	**$112**	**$5**	**$–**	**$8**
Liabilities	**$(186)**	**$(19)**	**$(51)**	**$(26)**
Notional Values				
Volumes[3]				
Purchases	**16,071**	**17**	**–**	**–**
Sales	**10,498**	**–**	**–**	**–**
U.S. dollars	**–**	**–**	**US 120**	**US 1,125**
Cross-currency	**–**	**–**	**136/US 100**	**–**
Net realized losses in the year[4]	**$(9)**	**$(35)**	**$–**	**$(33)**
Maturity dates	**2011-2015**	**2011-2013**	**2011-2014**	**2011-2015**

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

(2) Fair values equal carrying values.

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

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

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $8 million and a notional amount of US$250 million. In 2010, net realized gains on fair value hedges were $4 million and were included in Interest Expense. In 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) In 2010, Net Income included a gain of $1 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. In 2010, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

The anticipated timing of settlement of the derivative contracts assumes constant commodity prices, interest rates and foreign exchange rates from December 31, 2010. Settlements will vary based on the actual value of these factors at the date of settlement. The anticipated timing of settlement of these contracts is as follows:

Year ended December 31 (millions of dollars)	Total	2011	2012 and 2013	2014 and 2015	2016 and Thereafter
Derivative financial instruments held for trading					
Assets	341	221	102	17	1
Liabilities	(337)	(191)	(121)	(24)	(1)
Derivative financial instruments in hedging relationships					
Assets	306	76	204	26	–
Liabilities	(282)	(146)	(120)	(16)	–
	28	(40)	65	3	–

Derivative Financial Instruments Summary
Information for the Company's derivative financial instruments for 2009 is as follows:

December 31 (all amounts in millions unless otherwise indicated)	2009 Power	Natural Gas	Oil Products	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading					
Fair Values[1]					
Assets	$150	$107	$5	$–	$25
Liabilities	$(98)	$(112)	$(5)	$(66)	$(68)
Notional Values					
Volumes[2]					
Purchases	15,275	238	180	–	–
Sales	13,185	194	180	–	–
Canadian dollars	–	–	–	–	574
U.S. dollars	–	–	–	US 444	US 1,325
Cross-currency	–	–	–	227/US 157	–
Net unrealized gains/(losses) in the year[3]	$3	$(5)	$1	$3	$27
Net realized gains/(losses) in the year[3]	$70	$(76)	$–	$36	$(22)
Maturity dates	2010-2015	2010-2014	2010	2010-2012	2010-2018
Derivative Financial Instruments in Hedging Relationships[4][5]					
Fair Values[1]					
Assets	$175	$2	$–	$–	$15
Liabilities	$(148)	$(22)	$–	$(43)	$(50)
Notional Values					
Volumes[2]					
Purchases	13,641	33	–	–	–
Sales	14,311	–	–	–	–
U.S. dollars	–	–	–	US 120	US 1,825
Cross-currency	–	–	–	136/US 100	–
Net realized gains /(losses) in the year[3]	$156	$(29)	$–	$–	$(37)
Maturity dates	2010-2015	2010-2014	–	2010-2014	2010-2020

(1) Fair values equal carrying values.

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

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

(4) 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. In 2009, realized gains on fair value hedges were $4 million and were included in Interest Expense. In 2009, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(5) In 2009, Net Income included losses 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. In 2009, there were no gains or losses included in Net Income for discontinued cash flow hedges. No amounts have been excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

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

December 31 (millions of dollars)	**2010**	2009
Current		
Other current assets	**273**	315
Accounts payable	**(337)**	(340)
Long term		
Intangibles and other assets (Note 7)	**374**	260
Deferred amounts (Note 13)	**(282)**	(272)

Derivative Financial Instruments of Joint Ventures

Included in the Derivative Financial Instruments Summary tables are amounts related to power derivatives used by one of the Company's joint ventures to manage commodity price risk. The Company's proportionate share of the fair value of these power sales derivatives was $48 million at December 31, 2010 (2009 – $105 million). These contracts mature from 2011 to 2015. The Company's proportionate share of the notional sales volumes of power associated with this exposure was 3,772 gigawatt hours (GWh) at December 31, 2010 (2009 – 6,312 GWh). The Company's proportionate share of the notional purchased volumes of power associated with this exposure was 2,322 GWh at December 31, 2010 (2009 – 2,747 GWh).

Fair Value Hierarchy

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

There were no transfers between Level I and Level II in 2010 and 2009. Financial assets and liabilities measured at fair value, including both current and non-current portions, are categorized as follows:

	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total	
December 31 (millions of dollars, pre-tax)	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
Natural Gas Inventory	**–**	–	**49**	73	**–**	–	**49**	73
Derivative Financial Instrument Assets:								
Interest rate contracts	**–**	–	**28**	40	**–**	–	**28**	40
Foreign exchange contracts	**10**	10	**179**	104	**–**	–	**189**	114
Power commodity contracts	**–**	–	**269**	311	**5**	14	**274**	325
Gas commodity contracts	**93**	55	**56**	49	**–**	–	**149**	104
Oil commodity contracts	**–**	–	**–**	5	**–**	–	**–**	5
Derivative Financial Instrument Liabilities:								
Interest rate contracts	**–**	–	**(47)**	(119)	**–**	–	**(47)**	(119)
Foreign exchange contracts	**(11)**	(6)	**(54)**	(120)	**–**	–	**(65)**	(126)
Power commodity contracts	**–**	–	**(299)**	(229)	**(8)**	(16)	**(307)**	(245)
Gas commodity contracts	**(178)**	(103)	**(15)**	(27)	**–**	–	**(193)**	(130)
Oil commodity contracts	**–**	–	**–**	(5)	**–**	–	**–**	(5)
Non-Derivative Financial Instruments:								
Available-for-sale assets	**20**	23	**–**	–	**–**	–	**20**	23
	(66)	(21)	**166**	82	**(3)**	(2)	**97**	59

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

(millions of dollars, pre-tax)	Derivatives[1]
Balance at December 31, 2008	–
New contracts[2]	(14)
Transfers into Level III[3]	12
Balance at December 31, 2009	(2)
New contracts[2]	**(16)**
Settlements	**(3)**
Transfers into Level III[4]	**3**
Transfers out of Level III[4][5]	**(38)**
Change in unrealized gains recorded in Net Income	**14**
Change in unrealized gains recorded in Other Comprehensive (Loss)/Income	**39**
Balance at December 31, 2010	**(3)**

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

(2) At December 31, 2010, the total amount of net gains included in Net Income attributable to derivatives that were entered into during the year and still held at the reporting date was $1 million (2009 – nil).

(3) These contracts were previously included in Level II but were reclassified to Level III due to reduced liquidity in the market to which they relate.

(4) Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which inputs are considered to be observable.

(5) As contracts near maturity, they are transferred out of Level III and into Level II.

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in an $8 million decrease or increase, respectively, in the fair value of outstanding derivative financial instruments included in Level III as at December 31, 2010.

NOTE 19 INCOME TAXES

Provision for Income Taxes

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Current			
Canada	**29**	(70)	383
Foreign	**(170)**	100	143
	(141)	30	526
Future			
Canada	**170**	339	(1)
Foreign	**351**	18	77
	521	357	76
Income Tax Expense	**380**	387	602

Geographic Components of Income

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Canada	**798**	1,095	1,234
Foreign	**969**	768	938
Income before Income Taxes and Non-Controlling Interests	**1,767**	1,863	2,172

Reconciliation of Income Tax Expense

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Income before income taxes and non-controlling interests	**1,767**	1,863	2,172
Federal and provincial statutory tax rate	**28.0%**	29.0%	29.5%
Expected income tax expense	**495**	540	641
Income tax differential related to regulated operations	**8**	39	44
Lower effective foreign tax rates	**(36)**	(63)	(5)
Tax rate and legislative changes	**–**	(30)	–
Income from equity investments and non-controlling interests	**(40)**	(37)	(45)
Change in valuation allowance	**–**	–	(9)
Other	**(47)**	(62)	(24)
Actual Income Tax Expense	**380**	387	602

Future Income Tax Assets and Liabilities

December 31 (millions of dollars)	**2010**	2009
Operating loss carryforwards	**494**	148
Unrealized losses on derivatives	**113**	56
Other post-employment benefits	**75**	72
Deferred amounts	**42**	42
Other	**143**	127
Future income tax assets	**867**	445
Difference in accounting and tax bases of plant, equipment and PPAs	**3,434**	2,642
Taxes on future revenue requirement	**321**	338
Unrealized foreign exchange gains on long-term debt	**161**	96
Pension benefits	**96**	75
Deferred credits	**40**	57
Unrealized gains on derivatives	**9**	32
Other	**28**	61
Future income tax liabilities	**4,089**	3,301
Net Future Income Tax Liabilities	**3,222**	2,856

At December 31, 2010, the Company has recognized the benefit of unused non-capital loss carryforwards of $42 million (2009 – $9 million) for federal and provincial purposes in Canada, which expire from 2014 to 2030.

At December 31, 2010, the Company has recognized the benefit of unused net operating loss carryforwards of US$1,320 million (2009 – US$379 million) for federal purposes in the U.S., which expire from 2028 to 2030.

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Future income tax liabilities would have increased at December 31, 2010, by approximately $105 million (2009 – $101 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $53 million, net of refunds received, were made in 2010 (2009 – $83 million; 2008 – $491 million).

NOTE 20 NOTES PAYABLE

	2010		2009	
	Outstanding December 31	**Weighted Average Interest Rate per Annum at December 31**	Outstanding December 31	Weighted Average Interest Rate per Annum at December 31
	(millions of dollars)		(millions of dollars)	
Canadian dollars	**601**	**1.2%**	327	0.3%
U.S. dollars (2010 – US$1,499; 2009 – US$1,299)	**1,491**	**0.7%**	1,360	0.4%
	2,092		1,687	

Notes payable consists of commercial paper outstanding and draws on bridge and line-of-credit facilities.

At December 31, 2010, total committed revolving and demand credit facilities of $5.1 billion were available. When drawn, interest on the lines of credit is charged at prime rates of Canadian chartered and U.S. banks, and at other negotiated financial bases. These unsecured credit facilities included the following:

- a $2.0 billion committed, syndicated, revolving TCPL credit facility maturing December 2012. The facility was fully available at December 31, 2010. The cost to maintain the credit facility was $2 million in each of 2010 and 2009;
- a US$300 million committed, syndicated, revolving credit facility, guaranteed by TransCanada and maturing February 2013. This facility is part of a US$1.0 billion TCPL USA credit facility discussed in Note 10. At December 31, 2010, this facility was fully drawn. The cost to maintain the US$1.0 billion credit facility was $1 million in each of 2010 and 2009;
- a US$1.0 billion committed, syndicated, revolving extendible TransCanada Keystone Pipeline, L.P. credit facility, guaranteed by TCPL and TCPL USA and maturing November 2011. The facility was fully available at December 31, 2010. The cost to maintain the credit facility was $5 million in 2010 (2009 – $2 million);
- a US$1.0 billion committed, syndicated, revolving TCPL USA credit facility maturing December 2012 with a one-year extension at the option of the borrower and guaranteed by TransCanada. At December 31, 2010, US$200 million was drawn on this facility. The cost to maintain the credit facility was $4 million in 2010 (2009 – nil); and
- demand lines totalling $800 million, which support the issuance of letters of credit and provide additional liquidity. At December 31, 2010, the Company had used approximately $382 million of these demand lines for letters of credit.

At December 31, 2008, TransCanada had drawn $255 million on a committed, unsecured, one-year bridge loan facility, which was used to fund a portion of the Ravenswood acquisition. In February 2009, the US$255 million was repaid and the facility was cancelled.

NOTE 21 ASSET RETIREMENT OBLIGATIONS

The estimated undiscounted cash flows required to settle the ARO with respect to certain regulated and non-regulated operations in the Natural Gas Pipelines segment were $62 million at December 31, 2010 (2009 – $64 million), calculated using an annual inflation rate ranging from one per cent to four per cent. The carrying value of these liabilities was $24 million at December 31, 2010 (2009 – $24 million) after discounting the estimated cash flows at rates ranging from 5.2 per cent to 11.0 per cent. At December 31, 2010, the expected timing of payment for settlement of the obligations ranged from 2011 to 2029.

The estimated undiscounted cash flows required to settle the ARO with respect to the Energy segment were $719 million at December 31, 2010 (2009 – $424 million), calculated using an annual inflation rate ranging from 2.0 per cent to 2.5 per cent. During 2010, the economic life of certain Energy assets was extended after reviewing market trends and asset conditions. As a result, the carrying value of this liability was revised to $42 million at December 31, 2010 (2009 – $87 million) after discounting the estimated cash flows at average rates ranging from 5.5 per cent to 6.8 per cent. At December 31, 2010, the expected timing of payment for settlement of the obligations ranged from 2018 to 2060.

Reconciliation of Asset Retirement Obligations[1]

(millions of dollars)	Natural Gas Pipelines	Energy	Total
Balance at January 1, 2008	25	63	88
New obligations and revisions in estimated cash flows	4	18	22
Accretion expense	2	4	6
Balance at December 31, 2008	31	85	116
New obligations and revisions in estimated cash flows	(9)	(4)	(13)
Accretion expense	2	6	8
Balance at December 31, 2009	24	87	111
New obligations and revisions in estimated cash flows	**(1)**	**(47)**	**(48)**
Accretion expense	**1**	**2**	**3**
Balance at December 31, 2010	**24**	**42**	**66**

(1) At December 31, 2010, ARO totalling $65 million (2009 – $110 million) and $1 million (2009 – $1 million) were included in Deferred Amounts and Accounts Payable, respectively.

NOTE 22 EMPLOYEE FUTURE BENEFITS

The Company sponsors DB Plans that cover a significant majority of employees. Pension benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment. Upon commencement of retirement, pension benefits in the Canadian DB Plans increase annually by a portion of the increase in the Consumer Price Index. Past service costs are amortized over the expected average remaining service life of employees, which is approximately eight years.

The Company also provides its employees with a Savings Plan in Canada, 401(k) Plans (DC Plans) in the U.S., and post-employment benefits other than pensions, including termination benefits and life insurance and medical benefits beyond those provided by government-sponsored plans. Past service costs are amortized over the expected average remaining life expectancy of former employees, which was approximately 12 years at December 31, 2010. Contributions to the Savings Plan and DC Plans are expensed as incurred. In 2010, the Company expensed $21 million (2009 and 2008 – $21 million) for the Savings Plan and DC Plans.

Total cash payments for employee future benefits, consisting of cash contributed by the Company to the DB Plans and other benefit plans, was $127 million in 2010 (2009 – $168 million; 2008 – $90 million), including $21 million in 2010 (2009 and 2008 – $21 million) related to the Savings Plan and DC Plans.

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2011, and the next required valuation will be as at January 1, 2012.

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2010**	2009	**2010**	2009
Change in Benefit Obligation				
Benefit obligation – beginning of year	**1,476**	1,332	**150**	144
Current service cost	**50**	45	**2**	2
Interest cost	**89**	89	**9**	9
Employee contributions	**4**	4	**1**	1
Benefits paid	**(73)**	(70)	**(9)**	(8)
Actuarial loss	**95**	107	**8**	10
Transfers	**(8)**	–	**–**	–
Foreign exchange rate changes	**(11)**	(31)	**(2)**	(8)
Benefit obligation – end of year	**1,622**	1,476	**159**	150
Change in Plan Assets				
Plan assets at fair value – beginning of year	**1,447**	1,193	**27**	26
Actual return on plan assets	**177**	206	**3**	5
Employer contributions	**98**	140	**8**	7
Employee contributions	**4**	4	**1**	1
Benefits paid	**(73)**	(70)	**(9)**	(8)
Transfers	**(8)**	–	**–**	–
Foreign exchange rate changes	**(9)**	(26)	**(1)**	(4)
Plan assets at fair value – end of year	**1,636**	1,447	**29**	27
Funded status – plan surplus/(deficit)	**14**	(29)	**(130)**	(123)
Unamortized net actuarial loss	**345**	329	**42**	37
Unamortized past service costs	**18**	21	**(3)**	(3)
Accrued Benefit Asset/(Liability), Net of Valuation Allowance of Nil	**377**	321	**(91)**	(89)

The accrued benefit asset/(liability) net of valuation allowance of nil in the Company's Balance Sheet was as follows:

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2010**	2009	**2010**	2009
Intangibles and other assets	**380**	323	**–**	–
Deferred amounts	**(3)**	(2)	**(91)**	(89)
	377	321	**(91)**	(89)

Included in the above benefit obligation and fair value of plan assets were the following amounts for plans that are not fully funded:

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2010**	2009	**2010**	2009
Benefit obligation	**(417)**	(390)	**(159)**	(150)
Plan assets at fair value	**391**	358	**29**	27
Funded Status – Plan Deficit	**(26)**	(32)	**(130)**	(123)

The Company's expected contributions in 2011 are approximately $98 million for the DB Plans and approximately $28 million for the other benefit plans, Savings Plan and DC Plans.

The following are estimated future benefit payments, which reflect expected future service:

(millions of dollars)	Pension Benefits	Other Benefits
2011	82	9
2012	85	9
2013	89	9
2014	92	10
2015	96	10
2016 to 2020	540	56

The significant weighted average actuarial assumptions adopted in measuring the Company's benefit obligations were as follows:

	Pension Benefit Plans		Other Benefit Plans	
December 31	**2010**	2009	**2010**	2009
Discount rate	**5.55%**	6.00%	**5.65%**	6.00%
Rate of compensation increase	**3.20%**	3.20%		

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan cost were as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31	**2010**	2009	2008	**2010**	2009	2008
Discount rate	**6.00%**	6.65%	5.30%	**6.00%**	6.50%	5.50%
Expected long-term rate of return on plan assets	**6.95%**	6.95%	6.95%	**7.80%**	7.75%	7.75%
Rate of compensation increase	**3.20%**	3.25%	3.60%			

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and estimating future levels and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in determining the overall expected rate of return. The discount rate is based on market interest rates of high-quality bonds that match the timing and benefits expected to be paid under each plan.

A nine per cent average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2011 measurement purposes. The rate was assumed to decrease gradually to five per cent by 2020 and remain at this level thereafter. A one per cent change in assumed health care cost trend rates would have the following effects:

(millions of dollars)	Increase	Decrease
Effect on total of service and interest cost components	1	(1)
Effect on post-employment benefit obligation	14	(12)

The Company's net benefit cost is as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2010**	2009	2008	**2010**	2009	2008
Current service cost	**50**	45	52	**2**	2	2
Interest cost	**89**	89	80	**9**	9	8
Actual return on plan assets	**(177)**	(206)	222	**(3)**	(5)	10
Actuarial loss/(gain)	**95**	107	(261)	**8**	10	(21)
Plan amendment	**–**	–	–	**–**	–	(11)
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**57**	35	93	**16**	16	(12)
Difference between expected and actual return on plan assets	**68**	107	(316)	**1**	3	(12)
Difference between actuarial loss/(gain) recognized and actual actuarial loss/(gain) on accrued benefit obligation	**(86)**	(101)	280	**(6)**	(8)	23
Difference between amortization of past service costs and actual plan amendments	**4**	4	4	**–**	–	11
Amortization of transitional obligation related to regulated business	**–**	–	–	**2**	2	2
	43	45	61	**13**	13	12

The Company pension plans' weighted average asset allocations and target allocations by asset category were as follows:

December 31	Percentage of Plan Assets		Target Allocations
Asset Category	**2010**	2009	**2010**
Debt securities	**37%**	40%	**35% to 60%**
Equity securities	**63%**	60%	**40% to 65%**
	100%	100%	

Debt securities included the Company's debt of $4 million (0.2 per cent of total plan assets) and $4 million (0.3 per cent of total plan assets) at December 31, 2010 and 2009, respectively. Equity securities included the Company's common shares of $3 million (0.2 per cent of total plan assets) and $8 million (0.6 per cent of total plan assets) at December 31, 2010 and 2009, respectively.

The assets of the pension plans are managed on a going concern basis subject to legislative restrictions. The plans' investment policies are to maximize returns within an acceptable risk tolerance. Pension assets are invested in a diversified manner with consideration given to the demographics of the plans' participants.

Employee Future Benefits of Joint Ventures

Certain of the Company's joint ventures sponsor DB Plans as well as post-employment benefits other than pensions, including defined life insurance and medical benefits beyond those provided by government-sponsored plans. The obligations of these plans are non-recourse to TransCanada. The following amounts in this note, including those in the accompanying tables, represent TransCanada's proportionate share with respect to these plans.

Total cash payments for employee future benefits, consisting of cash contributed by the Company's joint ventures to DB Plans and other benefit plans was $58 million in 2010 (2009 – $54 million; 2008 – $42 million).

The Company's joint ventures measure the benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuations of the pension plans for funding purposes were as at January 1, 2011, and the next required valuations will be as at January 1, 2012.

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2010**	2009	**2010**	2009
Change in Benefit Obligation				
Benefit obligation – beginning of year	**695**	599	**170**	133
Current service cost	**19**	16	**8**	5
Interest cost	**42**	40	**10**	9
Employee contributions	**7**	6	**–**	–
Benefits paid	**(31)**	(33)	**(5)**	(4)
Actuarial loss	**132**	68	**25**	27
Foreign exchange rate changes	**–**	(1)	**–**	–
Benefit obligation – end of year	**864**	695	**208**	170
Change in Plan Assets				
Plan assets at fair value – beginning of year	**641**	556	**–**	–
Actual return on plan assets	**57**	63	**–**	–
Employer contributions	**53**	50	**5**	4
Employee contributions	**7**	6	**–**	–
Benefits paid	**(31)**	(33)	**(5)**	(4)
Foreign exchange rate changes	**–**	(1)	**–**	–
Plan assets at fair value – end of year	**727**	641	**–**	–
Funded status – plan deficit	**(137)**	(54)	**(208)**	(170)
Unamortized net actuarial loss	**230**	113	**49**	25
Unamortized past service costs	**–**	–	**2**	2
Accrued Benefit Asset/(Liability), Net of Valuation Allowance of Nil	**93**	59	**(157)**	(143)

The accrued benefit asset/(liability), net of valuation allowance of nil in the Company's Balance Sheet was as follows:

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2010**	2009	**2010**	2009
Intangibles and other assets	**93**	60	**–**	–
Deferred amounts	**–**	(1)	**(157)**	(143)
	93	59	**(157)**	(143)

The following amounts were included in the above benefit obligation and fair value of plan assets for plans that are not fully funded:

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2010**	2009	**2010**	2009
Benefit obligation	**(864)**	(695)	**(208)**	(170)
Plan assets at fair value	**727**	641	**–**	–
Funded Status – Plan Deficit	**(137)**	(54)	**(208)**	(170)

The expected total contributions of the Company's joint ventures in 2011 are approximately $87 million for the pension benefit plans and approximately $7 million for the other benefit plans.

The following are estimated future benefit payments, which reflect expected future service:

(millions of dollars)	Pension Benefits	Other Benefits
2011	40	6
2012	43	7
2013	47	7
2014	51	8
2015	54	9
2016 to 2020	324	55

The significant weighted average actuarial assumptions adopted in measuring the benefit obligations of the Company's joint ventures were as follows:

	Pension Benefit Plans		Other Benefit Plans	
December 31	**2010**	2009	**2010**	2009
Discount rate	**5.25%**	6.00%	**5.10%**	5.80%
Rate of compensation increase	**3.50%**	3.50%		

The significant weighted average actuarial assumptions adopted in measuring the net benefit plan costs of the Company's joint ventures were as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31	**2010**	2009	2008	**2010**	2009	2008
Discount rate	**6.00%**	6.75%	5.25%	**5.80%**	6.40%	5.15%
Expected long-term rate of return on plan assets	**7.00%**	7.00%	7.00%			
Rate of compensation increase	**3.50%**	3.50%	3.50%			

A one percentage point change in assumed health care cost trend rates would have the following effects:

(millions of dollars)	Increase	Decrease
Effect on total of service and interest cost components	3	(2)
Effect on post-employment benefit obligation	26	(22)

The Company's proportionate share of net benefit cost of joint ventures is as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2010**	2009	2008	**2010**	2009	2008
Current service cost	**19**	16	27	**8**	5	8
Interest cost	**42**	40	42	**10**	9	9
Actual return on plan assets	**(57)**	(63)	78	**–**	–	–
Actuarial loss/(gain)	**132**	68	(229)	**25**	27	(45)
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**136**	61	(82)	**43**	41	(28)
Difference between expected and actual return on plan assets	**12**	25	(122)	**–**	–	–
Difference between actuarial loss/(gain) recognized and actual actuarial loss/(gain) on accrued benefit obligation	**(128)**	(67)	239	**(24)**	(28)	48
	20	19	35	**19**	13	20

The weighted average asset allocations and target allocations by asset category in the pension plans of the Company's joint ventures were as follows:

December 31	Percentage of Plan Assets		Target Allocations
Asset Category	**2010**	2009	**2010**
Debt securities	**41%**	40%	**40%**
Equity securities	**59%**	60%	**60%**
	100%	100%	

Debt securities included the Company's debt of $1 million (0.2 per cent of total plan assets) and $1 million (0.1 per cent of total plan assets) at December 31, 2010 and 2009, respectively. Equity securities included the Company's common shares of $4 million (0.5 per cent of total plan assets) and $4 million (0.6 per cent of total plan assets) at December 31, 2010 and 2009, respectively.

The assets of the joint ventures' pension plans are managed on a going concern basis subject to legislative restrictions. The plans' investment policies are to maximize returns within an acceptable risk tolerance. Pension assets are invested in a diversified manner with consideration given to the demographics of the plans' participants.

NOTE 23 CHANGES IN OPERATING WORKING CAPITAL

Year ended December 31 (millions of dollars)	**2010**	2009	2008
(Increase)/decrease in accounts receivable	**(305)**	314	(197)
Decrease/(increase) in inventories	**70**	(19)	82
Increase in other current assets	**(89)**	(249)	(61)
Increase/(decrease) in accounts payable	**84**	(154)	213
(Decrease)/increase in accrued interest	**(9)**	18	98
(Increase)/Decrease in Operating Working Capital	**(249)**	(90)	135

NOTE 24 COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Operating Leases

Future annual payments, net of sub-lease receipts, under the Company's operating leases for various premises, services and equipment are approximately as follows:

Year ended December 31 (millions of dollars)	Minimum Lease Payments	Amounts Recoverable under Sub-leases	Net Payments
2011	83	(9)	74
2012	80	(5)	75
2013	79	(4)	75
2014	76	(4)	72
2015	73	(3)	70
2016 and thereafter	419	(1)	418
	810	(26)	784

The operating lease agreements for premises, services and equipment expire at various dates through 2052, with an option to renew certain lease agreements for periods of one year to 10 years. Net rental expense on operating leases in 2010 was $107 million (2009 – $91 million; 2008 – $52 million).

TransCanada's commitments under the Alberta PPAs are considered to be operating leases and a portion of these PPAs has been subleased to third parties under similar terms and conditions. Future payments under these PPAs have been excluded from operating leases in the above table, as these payments are dependent upon plant availability among other factors. TransCanada's share of power purchased under the PPAs in 2010 was $363 million (2009 – $384 million; 2008 – $398 million). The generating capacities and expiry dates of the PPAs are as follows:

	Megawatts	Expiry Date
Sundance A	560	December 31, 2017
Sundance B	353	December 31, 2020
Sheerness	756	December 31, 2020

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business.

Other Commitments

At December 31, 2010, TransCanada was committed to Natural Gas Pipelines capital expenditures totalling approximately $0.2 billion, primarily related to construction costs of the Alberta System and Guadalajara.

At December 31, 2010, the Company was committed to Oil Pipelines capital expenditures totalling approximately $1.2 billion, primarily related to construction costs of the Keystone U.S. Gulf Coast Expansion.

At December 31, 2010, the Company was committed to Energy capital expenditures totalling approximately $0.6 billion, primarily related to its share of the construction costs of Bruce Power and Cartier Wind.

Contingencies

TransCanada is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2010, the Company accrued approximately $59 million (2009 – $67 million) related to operating facilities, which represents the estimated amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

TransCanada and its subsidiaries are subject to various legal proceedings and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

Guarantees

TransCanada and its joint venture partners on Bruce Power, Cameco Corporation and BPC Generation Infrastructure Trust (BPC), have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, a lease agreement and contractor services. The guarantees have terms ranging from 2018 to perpetuity. In addition, TransCanada and BPC have each severally guaranteed one-half of certain contingent financial obligations related to an agreement with the Ontario Power Authority to refurbish and restart Bruce A power generation units. The guarantees were provided as part of the reorganization of Bruce Power in 2005 and have terms ending in 2018 and 2019. TransCanada's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated to be $739 million at December 31, 2010. The fair value of these Bruce Power guarantees is estimated to be $42 million. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to redelivery of natural gas, PPA payments and the payment of liabilities. TransCanada's share of the potential exposure under these guarantees was estimated at December 31, 2010 to range from $227 million to a maximum of $539 million. The fair value of these guarantees is estimated to be $9 million, which has been included in Deferred Amounts. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners.