

TRANSCANADA CORP
Form 40-F
February 15, 2012

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U.S. Securities and Exchange Commission
Washington, D.C. 20549

Form 40-F

o **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

ý **ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended **December 31, 2011** Commission File Number **1-31690**

TRANSCANADA CORPORATION

(Exact Name of Registrant as specified in its charter)

Canada

(Jurisdiction of incorporation or organization)

4922, 4923, 4924, 5172

(Primary Standard Industrial Classification Code Number (if applicable))

Not Applicable

(I.R.S. Employer Identification Number (if applicable))

**TransCanada Tower, 450 1 Street S.W.
Calgary, Alberta, Canada, T2P 5H1
(403) 920-2000**

(Address and telephone number of Registrant's principal executive offices)

**TransCanada PipeLine USA Ltd., 717 Texas Street,
Houston, Texas, 77002-2761; (832) 320-5201**

(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered pursuant to section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Shares (including Rights under Shareholder Rights Plan)	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**
Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: **None**

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For annual reports, indicate by check mark the information filed with this Form:

Annual Information Form

Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

**At December 31, 2011, 703,861,065 common shares;
22,000,000 Cumulative Redeemable First Preferred Shares, Series 1;
14,000,000 Cumulative Redeemable First Preferred Shares, Series 3; and
14,000,000 Cumulative Redeemable First Preferred Shares, Series 5
were issued and outstanding**

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the *Exchange Act* during the preceding 12 months (or such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files). Yes No

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The documents (or portions thereof) forming part of this Form 40-F are incorporated by reference into the following registration statements under the *Securities Act of 1933*, as amended:

Form	Registration No.
S-8	333-5916
S-8	333-8470
S-8	333-9130
S-8	333-151736
F-3	33-13564
F-3	333-6132
F-10	333-151781
F-10	333-161929
F-10	333-177788

AUDITED CONSOLIDATED ANNUAL FINANCIAL STATEMENTS AND MANAGEMENT'S DISCUSSION & ANALYSIS

Except sections specifically referenced below which shall be deemed incorporated by reference herein and filed, no other portion of the TransCanada Corporation Annual Report to Shareholder except as otherwise specifically incorporated by reference in the TransCanada Corporation Annual Information Form shall be deemed filed with the U.S. Securities and Exchange Commission (the "Commission") as part of this report under the Exchange Act.

A. Audited Annual Financial Statements

For audited consolidated financial statements, including the auditors' report, see pages 103 through 164 of the TransCanada Corporation 2011 Annual Report to Shareholders included herein. See Note 25 of the Notes to Audited Consolidated Financial Statements on pages 157 through 164 of the TransCanada Corporation 2011 Annual Report to Shareholders, reconciling the significant differences between Canadian and United States generally accepted accounting principles.

B. Management's Discussion & Analysis

For management's discussion and analysis, see pages 6 through 102 of the TransCanada Corporation 2011 Annual Report to Shareholders included herein under the heading "Management's Discussion & Analysis".

C. Management's Report on Internal Control Over Financial Reporting

For management's report on internal control over financial reporting, see "Report of Management" that accompanies the Audited Consolidated Financial Statements on page 103 of the TransCanada Corporation 2011 Annual Report to Shareholders included herein.

UNDERTAKING

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an Annual Report on Form 40-F arises; or transactions in said securities.

DISCLOSURE CONTROLS AND PROCEDURES

For information on disclosure controls and procedures, see "Controls and Procedures" in Management's Discussion and Analysis on pages 88 and 89 of the TransCanada Corporation 2011 Annual Report to Shareholders.

AUDIT COMMITTEE FINANCIAL EXPERT

The Registrant's board of directors has determined that it has at least one audit committee financial expert serving on its audit committee. Mr. Kevin E. Benson has been designated an audit committee financial expert and is independent, as that term is defined by the New York Stock Exchange's listing standards applicable to the Registrant. The Commission has indicated that the designation of Mr. Benson as an audit committee financial expert does not make Mr. Benson an "expert" for any purpose, impose any duties, obligations or liability on Mr. Benson that are greater than those imposed on members of the audit committee and board of directors who do not carry this designation or affect the duties, obligations or liability of any other member of the audit committee.

CODE OF ETHICS

The Registrant has adopted codes of business ethics for its President and Chief Executive Officer, Chief Financial Officer, Controller, directors, employees and contractors. The Registrant's codes are available on its website at www.transcanada.com. No waivers have been granted from any provision of the codes during the 2011 fiscal year.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

For information on principal accountant fees and services, see "Corporate governance Audit committee Pre-approval policies and procedures" and "Corporate governance Audit committee External auditor service fees" on pages 32 and 33 of the TransCanada Corporation Annual Information Form.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant has no off-balance sheet arrangements, as defined in this Form, other than the guarantees and commitments described in Note 24 of the Notes to the Audited Consolidated Financial Statements attached to this Form 40-F and incorporated herein by reference.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

For information on Tabular Disclosure of Contractual Obligations, see "Contractual Obligations" in Management's Discussion and Analysis on pages 67 and 68 of the TransCanada Corporation 2011 Annual Report to Shareholders.

IDENTIFICATION OF THE AUDIT COMMITTEE

The Registrant has a separately-designated standing Audit Committee. The members of the Audit Committee are:

Chair: K.E. Benson
Members: D.H. Burney
E.L. Draper
P.L. Joskow
J.A. MacNaughton
D.M.G. Stewart

FORWARD-LOOKING INFORMATION

This document contains 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", "intend", "target", "plan" 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 plans and financial outlook. Forward-looking statements in this document may include, but are not limited to, statements regarding:

anticipated business prospects;

financial performance of TransCanada and its subsidiaries and affiliates;

expectations or projections about strategies and goals for growth and expansion;

expected cash flows;

expected costs;

expected costs for projects under construction;

expected schedules for planned projects (including anticipated construction and completion dates);

expected regulatory processes and outcomes;

expected outcomes with respect to legal proceedings, including arbitration;

expected capital expenditures;

expected operating and financial results; and

expected impact of future commitments and contingent liabilities.

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These forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. By their nature, forward-looking statements are subject to various assumptions, risks and uncertainties which could cause TransCanada's actual results and achievements to differ materially from the anticipated results or expectations expressed or implied in such statements.

Key assumptions on which TransCanada's forward-looking statements are based include, but are not limited to, assumptions about:

inflation rates, commodity prices and capacity prices;

timing of debt issuances and hedging;

regulatory decisions and outcomes;

arbitration decisions and outcomes;

foreign exchange rates;

interest rates;

tax rates;

planned and unplanned outages and utilization of the Company's pipeline and energy assets;

asset reliability and integrity;

access to capital markets;

anticipated construction costs, schedules and completion dates; and

acquisitions and divestitures.

The risks and uncertainties that could cause actual results or events to differ materially from current expectations include, but are not limited to:

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;

amount of capacity payments and revenues from the Company's energy business;

regulatory decisions and outcomes;

outcomes with respect to legal proceedings, including arbitration;

counterparty performance;

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;

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access to capital markets;

interest and currency exchange rates;

weather;

technological developments; and

economic conditions in North America.

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 against placing undue reliance on forward-looking information, which is given as of the date it is expressed in this document or otherwise, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to publicly update or revise any forward-looking information in this document or otherwise, whether as a result of new information, future events or otherwise, except as required by law.

SIGNATURES

Pursuant to the requirements of the *Exchange Act*, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this Annual Report to be signed on its behalf by the undersigned, thereto duly authorized, in the City of Calgary, Province of Alberta, Canada.

TRANSCANADA CORPORATION

Per: /s/ DONALD R. MARCHAND

DONALD R. MARCHAND

Executive Vice-President and Chief Financial Officer

Date: February 15, 2012

DOCUMENTS FILED AS PART OF THIS REPORT

- 13.1 TransCanada Corporation Annual Information Form for the year ended December 31, 2011.
- 13.2 Management's Discussion and Analysis (included on pages 6 through 102 of the TransCanada Corporation 2011 Annual Report to Shareholders).
- 13.3 2011 Audited Consolidated Financial Statements (included on pages 103 through 164 of the TransCanada Corporation 2011 Annual Report to Shareholders), including the auditors' report thereon.
- 13.4 Independent Auditors' Report of Registered Public Accounting Firm on the 2011 Audited Consolidated Financial Statements.
- 13.5 Report of Independent Registered Public Accounting Firm on the effectiveness of TransCanada's Internal Control Over Financial Reporting, as of December 31, 2011.

EXHIBITS

- 23.1 Consent of KPMG LLP, Independent Registered Public Accounting Firm.
 - 31.1 Certification of Chief Executive Officer pursuant to Section 302 of the *Sarbanes-Oxley Act of 2002*.
 - 31.2 Certification of Chief Financial Officer pursuant to Section 302 of the *Sarbanes-Oxley Act of 2002*.
 - 32.1 Certification of Chief Executive Officer regarding Periodic Report containing Financial Statements.
 - 32.2 Certification of Chief Financial Officer regarding Periodic Report containing Financial Statements.
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TransCanada Corporation

2011 Annual information form

February 13, 2012

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Presentation of information

Unless the context indicates otherwise, a reference in this Annual Information Form ("AIF") to "TransCanada", the "Company", "we", "us" and "our" includes TransCanada Corporation and the subsidiaries of TransCanada Corporation through which its various business operations are conducted. In particular, "TransCanada" includes references to TransCanada PipeLines Limited ("TCPL"). Where TransCanada is referred to with respect to actions that occurred prior to its 2003 plan of arrangement with TCPL, which is described below under the heading *TransCanada Corporation Corporate Structure*, these actions were taken by TCPL or its subsidiaries. The term "subsidiary", when referred to in this AIF, with reference to TransCanada means direct and indirect wholly owned subsidiaries of, and legal entities controlled by, TransCanada or TCPL, as applicable.

Unless otherwise noted, the information contained in this AIF is given at or for the year ended December 31, 2011 ("Year End"). Amounts are expressed in Canadian dollars unless otherwise indicated. Information in relation to metric conversion can be found at Schedule A to this AIF. Terms defined throughout this AIF are listed in the *Glossary* found at the end of this AIF. Financial information is presented in accordance with Canadian generally accepted accounting principles.

Certain portions of TransCanada's Management's Discussion and Analysis dated February 13, 2012 ("MD&A") are incorporated by reference into this AIF as stated below. The MD&A can be found on SEDAR (www.sedar.com) under TransCanada's profile.

Effective January 1, 2012, TransCanada adopted U.S. generally accepted accounting principles ("U.S. GAAP") for reporting purposes. For more information regarding TransCanada's adoption of U.S. GAAP, refer to the MD&A under the headings *Accounting Changes Future Accounting Changes U.S. GAAP*.

Forward looking information

This AIF, including the MD&A disclosure incorporated by reference herein, contains 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", "intend", "target", "plan" 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 plans and financial outlook. Forward-looking statements in this document may include, but are not limited to, statements regarding:

- anticipated business prospects
- financial performance of TransCanada and its subsidiaries and affiliates
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows
- expected costs
- expected costs for projects under construction
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes
- expected outcomes with respect to legal proceedings, including arbitration
- expected capital expenditures
- expected operating and financial results, and
- expected impact of future commitments and contingent liabilities.

These forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. By their nature, forward-looking statements are subject to various assumptions, risks and uncertainties which could cause TransCanada's actual results and achievements to differ materially from the anticipated results or

expectations expressed or implied in such statements.

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Key assumptions on which TransCanada's forward-looking statements are based include, but are not limited to, assumptions about:

inflation rates, commodity prices and capacity prices
timing of debt issuances and hedging
regulatory decisions and outcomes
arbitration decisions and outcomes
foreign exchange rates
interest rates
tax rates
planned and unplanned outages and utilization of the Company's pipeline and energy assets
asset reliability and integrity
access to capital markets
anticipated construction costs, schedules and completion dates, and
acquisitions and divestitures.

The risks and uncertainties that could cause actual results or events to differ materially from current expectations include, but are not limited to:

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
amount of capacity payments and revenues from the Company's energy business
regulatory decisions and outcomes
outcomes with respect to legal proceedings, including arbitration
counterparty performance
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
weather
technological developments, and

economic conditions in North America.

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 against placing undue reliance on forward-looking information, which is given as of the date it is expressed in this AIF, or the MD&A disclosure incorporated by reference herein, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to publicly update or revise any forward-looking information in this AIF or the MD&A disclosure incorporated by reference herein whether as a result of new information, future events or otherwise, except as required by law.

TransCanada Corporation

Corporate structure

Our head office and registered office are located at 450 - 1st Street S.W., Calgary, Alberta, T2P 5H1. TransCanada was incorporated pursuant to the provisions of the *Canada Business Corporations Act* ("CBCA") on February 25, 2003 in connection with a plan of arrangement which established TransCanada as the parent company of TCPL. The arrangement was approved by TCPL common shareholders on April 25, 2003 and, following court approval and the filing of Articles of Arrangement, the arrangement became effective May 15, 2003. Pursuant to the arrangement, the common shareholders of TCPL exchanged each of their

TCPL common shares for one common share of TransCanada. The debt securities and preferred shares of TCPL remained obligations and securities of TCPL. TCPL continues to carry on business as the principal operating subsidiary of the TransCanada group of entities. TransCanada does not hold any material assets directly, other than the common shares of TCPL and receivables from certain of TransCanada's subsidiaries.

Intercorporate relationships

The following diagram presents the name and jurisdiction of incorporation, continuance or formation of TransCanada's principal subsidiaries as at Year End. Each of the subsidiaries shown has total assets that exceeded 10 per cent of the total consolidated assets of TransCanada or revenues that exceeded 10 per cent of the total consolidated revenues of TransCanada as at Year End. TransCanada beneficially owns, controls or directs, directly or indirectly, 100 per cent of the voting shares in each of these subsidiaries, with the exception of TransCanada Keystone Pipeline, LP in which TransCanada indirectly holds 100 per cent of the partnership interests.

The above diagram does not include all of the subsidiaries of TransCanada. The assets and revenues of excluded subsidiaries in the aggregate did not exceed 20 per cent of the total consolidated assets or total consolidated revenues of TransCanada as at Year End.

General development of the business

Our reportable business segments are "Natural Gas Pipelines", "Oil Pipelines" and "Energy". Natural Gas Pipelines and Oil Pipelines are principally comprised of the Company's respective natural gas and oil pipelines in Canada, the U.S. and Mexico and our regulated natural gas storage operations in the U.S. Energy includes the Company's power operations and the non-regulated natural gas storage business in Canada. Further information regarding our Natural Gas Pipelines, Oil Pipelines and Energy businesses is available in this AIF under the heading *Business of TransCanada*.

Summarized below are significant developments that have occurred in TransCanada's Natural Gas Pipelines, Oil Pipelines and Energy businesses, respectively, and the significant acquisitions, dispositions, events or conditions which have had an influence on that development,

during the last three financial years.

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Developments in the Natural Gas Pipelines business

Date	Description of development
Canadian Mainline	
December 2009	The National Energy Board ("NEB") approved TransCanada's application for 2010 final tolls for the Canadian Mainline, effective January 1, 2010. The 2010 calculated return on equity was 8.52 per cent. Reduced throughput and greater use of shorter distance transportation contracts resulted in an increase in tolls for 2010 compared to 2009.
December 2010	TransCanada filed an application with the NEB for approval of the interim 2011 tolls for the Canadian Mainline which contained certain changes to the tolling mechanism to reduce long haul tolls. The NEB decided not to approve the tolls as requested in the interim tolls application and set the then current 2010 tolls as interim commencing January 1, 2011.
January - February 2011	TransCanada received approval for revised interim tolls, effective March 1, 2011 which increased interim tolls to more closely align with tolls calculated in accordance with the 2007-2011 settlement with stakeholders and will more closely reflect the Canadian Mainline's costs and throughput for 2011.
September - October 2011	TransCanada filed with the NEB a 2012 Tolls Application and Restructuring Proposal (the "Restructuring Proposal") designed to enhance the long-term economic viability of the Canadian Mainline. The application also seeks approval of tolls for 2012-2013, including an after tax weighted average cost of capital return of 7.0 percent assuming the Restructuring Proposal is approved. The Restructuring Proposal includes toll design and service and pricing modifications, a depreciation proposal, and geographic extension of the Alberta System service by NOVA Gas Transmission Ltd. ("NGTL") acquiring capacity on the Canadian Mainline and Foothills systems. The application has been set down for hearing (proceeding RH-003-2011) in the second to fourth quarters of 2012, and a decision is expected in late 2012 or early 2013.
November 2011	TransCanada refiled a supplemental application with the NEB to construct \$130 million of new pipeline infrastructure on the Canadian Mainline, to receive Marcellus shale natural gas from the U.S. at the Niagara Falls receipt point for further transportation to Eastern markets. Subject to regulatory approval, deliveries from Niagara Falls are expected to begin at a rate of 230 million cubic feet per day ("MMcf/d") in November 2012 and then increase to 350 MMcf/d by November 2013.
November - December 2011	TransCanada filed for and received approval to implement interim 2012 tolls on the Canadian Mainline effective January 1, 2012, at the same level as the currently approved 2011 final tolls. The NEB approved TransCanada's application for 2011 final tolls for the Canadian Mainline at the level of the tolls that were being charged on an interim basis. Final 2011 tolls were calculated in accordance with previously approved toll methodologies and were based on the principles contained in the 2007-2011 settlement with stakeholders, with adjustments to reduce toll impacts.

Certain aspects of the 2011 revenue requirement were rolled into the RH-003-2011 proceeding referred to above.

Alberta System

February 2009	The NEB approved TransCanada's June 2008 application for federal regulation of the Alberta System effective April 29, 2009.
February 2009	TransCanada announced the successful completion of a binding open season, securing support for firm transportation contracts of 378 MMcf/d for the Horn River pipeline.
February 2010	TransCanada filed an application with the NEB for approval to construct and operate the Horn River pipeline.
March 2010	The North Central Corridor expansion of the Alberta System was completed.
March 2010	The NEB approved TransCanada's application after a public hearing to construct and operate the Groundbirch pipeline project.
June 2010	TransCanada reached a three year settlement agreement with the Alberta System shippers and other interested parties and filed a 2010-2012 Revenue Requirement Settlement Application with the NEB.
August 2010	The NEB approved TransCanada's November 2009 application for the Alberta System's Rate Design Settlement and the commercial integration of the ATCO Pipelines system with the Alberta System.
September 2010	The NEB approved the Alberta System's 2010-2012 Revenue Requirement Settlement Application.
October 2010	The NEB approved final 2010 rates for the Alberta System, which reflect the Alberta System 2010-2012 Revenue Requirement Settlement and Rate Design Settlement.
December 2010	The NEB approved the interim 2011 tolls for the Alberta System reflecting the 2010-2012 Revenue Requirement Settlement and continuing to transition to the toll methodology approved in the Rate Design Settlement.
December 2010	Groundbirch pipeline was completed and began transporting natural gas from the Montney shale gas formation into the Alberta System.
January 2011	TransCanada received approval from the NEB to construct the Horn River pipeline.

Date	Description of development
March 2011	TransCanada commenced construction of the \$275 million Horn River project, with a targeted completion date of second quarter 2012. In addition, the Company executed an agreement to extend the Horn River pipeline by approximately 100 kilometer ("km") (62 miles) at an estimated cost of \$230 million. An application requesting approval to construct and operate this extension was filed with the NEB in October 2011. The total contracted volumes for Horn River, including the extension, are expected to be approximately 900 MMcf/d by 2020.
August 2011	The NEB approved construction of a 24 km (15 miles) extension of the Groundbirch pipeline and construction commenced in August, with an expected in service date of April 2012.
October 2011	Commercial integration of the NGTL and ATCO Pipelines systems commenced. Under an agreement, the facilities of NGTL and ATCO Pipelines are commercially operated as a single transmission system and transportation service is provided to customers by NGTL pursuant to NGTL's tariff and suite of rates and services. The agreement further identifies distinct geographic areas within Alberta for the construction of new facilities by each of NGTL and ATCO Pipelines.
October 2011	The NEB approved the construction of natural gas pipeline projects for the Alberta System with a capital cost of approximately \$910 million. Further pipeline projects with a total capital cost of approximately \$810 million are awaiting NEB decision.
November - December 2011	The regulatory decisions by which commercial integration of the NGTL and ATCO Pipelines systems were authorized are the subject of appeals to the Federal Court of Appeal. The timing of the hearing of the appeals is uncertain, but TransCanada expects it to be before the end of 2012.
December 2011	TransCanada filed for interim 2012 tolls on the Alberta System to be effective January 1, 2012. These tolls have been approved on an interim basis pending the outcome of the NEB's decision on the application filed for the Restructuring Proposal.

Mackenzie Gas Project

December 2009	A Joint Review Panel of the Canadian government released a report on environmental and socio-economic factors in relation to the Mackenzie Gas Project. The report was submitted to the NEB as part of the review process for approval of the project.
December 2010	The NEB approved the proponents' application to construct the Mackenzie Gas Project subject to numerous conditions.
March 2011	The NEB issued a Certificate of Public Convenience and Necessity for the Mackenzie Gas Project.

Alaska Pipeline Project

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June 2009	TransCanada reached an agreement with ExxonMobil Corporation to jointly advance the Alaska Pipeline Project. A joint project team is developing the engineering, environmental, aboriginal relations and commercial work.
April 2010	The Alaska Pipeline open season commenced.
Third Quarter 2010	Interested shippers on the proposed Alaska Pipeline Project submitted conditional commercial bids in the open season that closed in July 2010. The Alaska Pipeline Project team continued to work with shippers to resolve conditional bids received as part of the project's open season in working toward a U.S. Federal Energy Regulatory Commission ("FERC") application deadline of October 2012 for the Alberta option that would extend from Prudhoe Bay to points near Fairbanks and Delta Junction, and then to the Alaska/Canada border where the pipeline would connect with a new pipeline in Canada.
January 2012	TransCanada commenced initial discussions with Alaska North Slope producers regarding an alternative pipeline route, the liquefied natural gas option, that would extend from Prudhoe Bay to liquefied natural gas facilities, to be built by third parties, located in south-central Alaska.
Bison	
December 2010	Construction of Bison pipeline, a 487 km (303 miles) pipeline, was completed.
January 2011	Bison pipeline was placed into commercial service.
May 2011	TransCanada closed the sale of a 25 per cent interest in each of Gas Transmission Northwest LLC and Bison Pipeline LLC to TC PipeLines, LP for a total transaction value of \$605 million, which included U.S. \$81 million or 25 percent of Gas Transmission Northwest LLC's debt outstanding.
GTN	
May 2011	TransCanada closed the sale of a 25 per cent interest in each of Gas Transmission Northwest LLC and Bison Pipeline LLC to TC PipeLines, LP for a total transaction value of \$605 million, which included U.S. \$81 million or 25 percent of Gas Transmission Northwest LLC's debt outstanding.
November 2011	The FERC approved a settlement agreement between GTN and its shippers for new transportation rates to be effective January 2012 through December 2015. This settlement also requires GTN to file for new rates that are to be effective January 2016.
Great Lakes	
November 2009	The FERC initiated an investigation to determine whether rates on Great Lakes were just and reasonable. In response, Great Lakes Gas Transmission Limited Partnership filed a cost and revenue study with the FERC in February 2010.
July 2010	The FERC approved, without modification, the settlement stipulation agreement reached among Great Lakes Gas Transmission Limited Partnership, active

participants and the FERC trial staff. As approved, the stipulation and agreement applies to all current and future shippers on Great Lakes.

Date	Description of development
North Baja	
July 2009	TransCanada completed the sale of North Baja Pipeline, LLC to TC PipeLines, LP.
Guadalajara	
May 2009	TransCanada announced that it was the successful bidder on a contract to build, own and operate the Guadalajara pipeline.
June 2011	The Guadalajara pipeline was completed. TransCanada and the Comisión Federal de Electricidad, Mexico's federal government owned electrical company have agreed to add a US\$60 million compressor station to the pipeline that is expected to be operational early in 2013.

Further information about developments in the Natural Gas Pipelines business can be found in the MD&A under the headings *TransCanada's Strategy, Natural Gas Pipelines Highlights, Natural Gas Pipelines Financial Analysis* and *Natural Gas Pipelines Opportunities and Developments*.

Developments in the Oil Pipelines business

Date	Description of development
Keystone	
August 2009	TransCanada became sole owner of the Keystone project through the purchase of ConocoPhillips' remaining interest for US\$553 million and the assumption of US\$197 million of short-term debt.
March 2010	The NEB approved TransCanada's application to construct and operate the Canadian portion of the Keystone U.S. Gulf Coast expansion ("Keystone XL").
April 2010	The U.S. Department of State issued a Draft Environmental Impact Statement for Keystone XL.
June 2010	Keystone commenced operating at a reduced maximum operating pressure as the first section of Keystone began delivering oil from Hardisty, Alberta to Wood River and Patoka in Illinois ("Wood River/Patoka").
November 2010	The open seasons for the Bakken Marketlink and Cushing Marketlink projects, which commenced in September 2010, closed successfully.
December 2010	The reduced maximum operating pressure restriction on the Canadian conversion section of the Wood River/Patoka section of Keystone was removed by the NEB following the completion of in-line inspections.
Fourth Quarter 2010	Construction of the second section of Keystone extending the pipeline from Steele City, Nebraska to Cushing, Oklahoma (the "Cushing Extension") was completed,

and line fill commenced in late 2010.

January 2011	Required operational modifications were completed on the Canadian conversion section of Keystone. As a result, the system was capable of operating at the approved design pressure.
February 2011	The commercial in service of the Cushing Extension commenced, and the Company also commenced recording earnings for the Wood River/Patoka section.
May 2011	Revised tolls came into effect for the Wood River/Patoka section.
Second Quarter 2011	The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration issued a corrective action order on Keystone as a result of two above-ground incidents at pump stations in North Dakota and Kansas. TransCanada filed a re-start plan with the U.S. Pipeline and Hazardous Material Safety Administration which was approved in June 2011.
August 2011	TransCanada received a Final Environmental Impact Statement regarding the Keystone XL U.S. Presidential Permit application.
November 2011	The U.S. Department of State announced that further analysis of route options for Keystone XL would need to be investigated, with a specific focus on the Sandhills area of Nebraska. The review could be completed as early as the first quarter of 2013.
December 2011	TransCanada announced that it received additional binding commitments in support of Keystone XL following the conclusion of the Keystone Houston Lateral open season, which commenced in August 2011.
January 2012	The U.S. Department of State denied TransCanada's application requesting a Presidential Permit to construct Keystone XL. The Company plans to submit a revised Presidential Permit application for Keystone XL.

Further information about developments in the Oil Pipelines business can be found in the MD&A under the headings *TransCanada's Strategy, Oil Pipelines Highlights, Oil Pipelines Financial Analysis* and *Oil Pipelines Opportunities and Developments*.

Developments in the Energy business

Date	Description of development
Ravenswood	
May 2009	Ravenswood's 981 MW Unit 30 returned to service. Subsequent to closing the acquisition of Ravenswood in August 2008, TransCanada experienced a forced outage event related to the unit. TransCanada has filed claims against the insurers to enforce its rights under the insurance policies and litigation proceedings are ongoing.
Third and Fourth Quarters 2011	Since July 2011, spot prices for capacity sales in the New York Zone J market have been negatively impacted by the manner in which the New York Independent System Operator ("NYISO") has applied pricing rules for a new power plant that recently began service in this market. TransCanada believes that this application of pricing rules by the NYISO is in direct contravention of a series of the FERC orders which direct how new entrant capacity is to be treated for the purpose of determining capacity prices. TransCanada and other parties have filed formal complaints with the FERC that are currently pending. The outcome of the complaints and longer-term impact that this development may have on Ravenswood is unknown. During third quarter 2011, the demand curve reset process was completed following the FERC's acceptance of the NYISO's September 22, 2011 compliance filing. This resulted in increased demand curve rates that apply going forward to 2014. Until the above noted NYISO actions relative to new unit pricing are resolved, capacity prices are expected to remain volatile.
Bécancour	
June 2011	Hydro-Québec Distribution ("Hydro-Québec") notified TransCanada it would exercise its option to extend the agreement to suspend all electricity generation from Bécancour throughout 2012. Under the original agreement, Hydro-Québec has the option, to extend the suspension on an annual basis until such time as regional electricity demand levels recover. TransCanada continues to receive capacity payments under the agreement similar to those that would have been received under the normal course of operation.
Bruce Power	
November 2011	Bruce Power commenced the approximately six month West Shift Plus outage as part of the life extension strategy for Unit 3. Subject to regulatory approval, Unit 3 is expected to return to service in second quarter 2012.
February 2011	The Bruce Power Refurbishment Implementation Agreement (the "BPRIA") was amended to extend the suspension date for Bruce A contingent support payments from December 31, 2011 to June 1, 2012. Contingent support payments received from the OPA by Bruce A are equal to the difference between the fixed prices under the BPRIA and spot market prices. As a result of the amendment, all output from Bruce A will be subject to spot prices effective June 1, 2012 until the restart of both Units 1 and 2 is complete. Bruce Power and the OPA had amended certain terms and conditions of the BPRIA in July 2009, which included: amendments to the Bruce B

Date	Description of development
Kibby Wind	
October 2009	The 22 turbine, 66 MW first phase of Kibby Wind was completed and placed in service.
October 2010	The 22 turbine, 66 MW second phase of Kibby Wind was completed and placed in service.
Sundance	
February 2011	TransCanada received notice from TransAlta Corporation ("TransAlta") under the Sundance A power purchase arrangement that TransAlta 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 power purchase arrangement in respect of those units. In December 2010, the Sundance 1 and 2 generating units were withdrawn from service and were subject to a force majeure claim by TransAlta in January 2011. TransCanada has disputed both claims under the binding dispute resolution process provided in the power purchase arrangement and both matters will be heard through a single binding arbitration process. The arbitration panel has scheduled a hearing in April 2012 for these claims.
Halton Hills	
September 2010	The 683 MW Halton Hills power plant was completed and placed in service.
Ontario Solar	
December 2011	Subject to a number of conditions precedent, TransCanada agreed to purchase nine Ontario solar power projects from Canadian Solar Solutions Inc. with a combined capacity of 86 MW for approximately \$470 million.

Further information about developments in the Energy business can be found in the MD&A under the headings *TransCanada's Strategy, Energy Highlights, Energy Financial Analysis* and *Energy Opportunities and Developments*.

Business of TransCanada

We are a leading North American energy infrastructure company focused on Natural Gas Pipelines, Oil Pipelines and Energy. At Year End, Natural Gas Pipelines accounted for approximately 49 per cent of revenues and 48 per cent of TransCanada's total assets, Oil Pipelines accounted for approximately 9 per cent of revenues and 19 per cent of TransCanada's total assets and Energy accounted for approximately 42 per cent of revenues and 29 per cent of TransCanada's total assets. The following table shows TransCanada's revenues from operations by segment, classified geographically, for the years ended December 31, 2011 and 2010.

Revenues from operations <i>(millions of dollars)</i>	2011	2010
Natural Gas Pipelines		
Canada - Domestic	\$ 2,187	\$ 2,125
Canada - Export(1)	787	837

United States and other	1,526	1,411
	4,500	4,373
Oil Pipelines		
Canada - Domestic		
Canada - Export(1)	300	
United States and other	527	
	827	NIL
Energy(2)		
Canada - Domestic	2,649	2,243
Canada - Export(1)		1
United States and other	1,163	1,447
	3,812	3,691
Total revenues(3)	\$ 9,139	\$ 8,064

- (1) Exports include pipeline revenues attributable to deliveries to U.S. pipelines and power deliveries to U.S. markets.
- (2) Revenues include sales of natural gas.
- (3) Revenues are attributed to countries based on country of origin of product or service.

The following is a description of each of TransCanada's three main areas of operations.

Natural Gas Pipelines business

TransCanada has substantial Canadian and U.S. natural gas pipeline and related holdings, including those listed below. The following natural gas pipelines are owned 100 per cent by TransCanada unless otherwise stated.

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TransCanada has the following natural gas pipelines and related holdings in Canada:

The Canadian Mainline is a 14,101 km (8,762 miles) pipeline 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.

The Alberta System is a 24,373 km (15,145 miles) pipeline system in Alberta and northeast British Columbia ("B.C.") which gathers natural gas for use within the province of Alberta and delivers it to provincial boundary points for connection with the Canadian Mainline and Foothills and with third party natural gas pipelines. During the past three completed financial years, TransCanada has enhanced the operating capacity of the Alberta System as follows:

the North Central Corridor, which extends the northern section of the Alberta System, was completed in March 2010;

the Groundbirch pipeline was completed in December 2010, connecting the Alberta System to natural gas supplies from the Montney shale gas formation in northeast B.C.; and

TransCanada continues to advance further pipeline development in B.C. and Alberta to transport unconventional shale gas supply as follows:

in January 2011, TransCanada received approval from the NEB to construct the proposed Horn River pipeline, an extension of the Alberta System to serve production from the new shale gas supply in the Horn River basin north of Fort Nelson, B.C. The Horn River pipeline is expected to be operational in the second quarter 2012. The Company has executed an agreement to extend the Horn River pipeline by approximately 100 km (62 miles), and an application requesting approval to construct and operate this extension was filed with the NEB in October 2011. This extension is projected to commence in 2014; and

the Company has filed applications with the NEB requesting approval for expansions to the Alberta System to accommodate requests for additional natural gas transmission service throughout the northwest and northeast portions of the Western Canada Sedimentary Basin. These new requests are expected to result in the need for further extensions and expansions of the Alberta System.

Foothills is a 1,241 km (771 miles) pipeline system in Western Canada which carries 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.

TransCanada Pipeline Ventures LP owns a 161 km (100 miles) pipeline and related facilities that supply natural gas to the oil sands region near Fort McMurray, Alberta as well as a 27 km (17 miles) pipeline that supplies natural gas to a petrochemical complex at Joffre, Alberta.

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

The Mackenzie Gas Project is a proposed 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.

TransCanada has the following natural gas pipelines and related holdings in the U.S.:

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ANR is a 16,656 km (10,350 miles) pipeline system which transports natural gas 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 connects with other natural gas pipelines, providing access to diverse sources of North American supply, including Western Canada, and the mid-continent and Rocky Mountain supply regions, and a variety of markets in the Midwestern and Northeastern U.S.

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Underground gas storage facilities owned and operated by American Natural Resources Company and ANR Storage Company provide regulated gas storage services to customers on the ANR and Great Lakes systems in upper Michigan. The ANR business unit owns and operates natural gas storage facilities throughout the State of Michigan with total natural gas storage capacity of 250 billion cubic feet ("Bcf").

GTN is TransCanada's 2,178 km (1,353 miles) pipeline system that transports Western Canada Sedimentary Basin and Rocky Mountain sourced natural gas to third party natural gas pipelines and markets in Washington, Oregon and California, and connects with the Tuscarora Gas Transmission Company's pipeline ("Tuscarora"). TransCanada operates GTN and effectively owns 83.3 per cent of the system through the combination of its direct ownership and its 33.3 per cent interest in TC PipeLines, LP which owns a 25 per cent interest in the pipeline.

Great Lakes is a 3,404 km (2,115 miles) natural gas pipeline system connecting to the Canadian Mainline and serving markets primarily in Eastern Canada and the Northeastern and Midwestern U.S. TransCanada operates Great Lakes and effectively owns 69.0 per cent of the system through its 53.6 per cent ownership interest and its indirect ownership, which it has through its 33.3 per cent interest in TC PipeLines, LP.

Bison is a 487 km (303 miles) pipeline from the Powder River Basin in Wyoming connecting to the Northern Border pipeline in Morton County, North Dakota. Bison became operational in January 2011. TransCanada operates Bison and effectively owns 83.3 per cent of the system through the combination of its direct ownership interest and its indirect ownership, which it has through its 33.3 per cent interest in TC PipeLines, LP.

Northern Border is 50 per cent owned by TC PipeLines, LP and is a 2,265 km (1,407 miles) natural gas pipeline system, which serves the U.S. Midwest. TransCanada operates Northern Border and effectively owns 16.7 per cent of the system through its 33.3 per cent interest in TC PipeLines, LP.

Tuscarora is 100 per cent owned by TC PipeLines, LP. TransCanada operates Tuscarora, 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 effectively owns 33.3 per cent of the system through its 33.3 per cent interest in TC PipeLines, LP.

North Baja is 100 per cent owned by TC PipeLines, LP. TransCanada operates North Baja, a pipeline system which extends 138 km (86 miles) from Ehrenberg, Arizona to a point near Ogilby, California on the California/Mexico border and connects with a third party natural gas pipeline system in Mexico. TransCanada operates North Baja and effectively owns 33.3 per cent of the system through its 33.3 per cent interest in TC PipeLines, LP.

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

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. TransCanada has a 61.7 per cent ownership interest in Portland and operates this pipeline.

TransCanada holds a 33.3 per cent interest in TC PipeLines, LP, a publicly held limited partnership of which a subsidiary of TransCanada acts as the general partner. The remaining interest of TC PipeLines, LP is widely held by the public. TC PipeLines, LP owns a 50 per cent interest in Northern Border, 46.4 per cent interest in Great Lakes, 25 per cent interest in GTN, 25 per cent interest in Bison, 100 per cent of Tuscarora and 100 per cent of North Baja.

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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 natural gas treatment plant at Prudhoe Bay, Alaska to Alberta, or an alternative pipeline to Valdez, Alaska. The Alaska Pipeline Project is a joint effort between TransCanada and ExxonMobil Corporation.

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TransCanada has the following natural gas pipeline and related holdings in Mexico and South America:

TransGas is a 344 km (214 miles) natural gas pipeline system which runs from Mariquita in the central region of Colombia to Cali in the southwest of Colombia. TransCanada holds a 46.5 per cent ownership interest in this pipeline.

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.

Tamazunchale is a 130 km (81 miles) natural gas pipeline in east central Mexico which extends from the facilities of Pemex Gas near Naranjos, Veracruz to an electricity generating station near Tamazunchale, San Luis Potosi.

The Guadalajara pipeline was completed in June 2011, and extends 310 km (193 miles), transporting natural gas from a liquefied natural gas terminal near Manzanillo on Mexico's Pacific coast to Guadalajara in Mexico.

Further information about the Company's pipeline holdings, developments and opportunities and significant regulatory developments which relate to Natural Gas Pipelines can be found in the MD&A under the headings *Natural Gas Pipelines, Natural Gas Pipelines Opportunities and Developments* and *Natural Gas Pipelines Financial Analysis*.

Oil Pipelines business

The Company's Keystone pipeline system and other opportunities in TransCanada's Oil Pipelines business are described below.

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 sections commenced commercial operations in June 2010 and February 2011, respectively. In January 2012, the U.S. Department of State denied TransCanada's application to construct Keystone XL, a 2,673 km (1,661 miles) extension and expansion of the pipeline to the U.S. Gulf Coast. The Company intends to re-apply for a Presidential Permit for Keystone XL.

Further information about the Company's pipeline holdings, developments and opportunities and significant regulatory developments which relate to Oil Pipelines can be found in the MD&A under the headings *Oil Pipelines, Oil Pipelines Opportunities and Developments* and *Oil Pipelines Financial Analysis*.

Regulation of the Natural Gas and Oil Pipelines businesses

Canada

Natural Gas Pipelines

Under the terms of the *National Energy Board Act* (Canada), the Canadian Mainline, TQM, Foothills, and the Alberta System (collectively, the "Systems") are regulated by the NEB. The NEB sets tolls that provide TransCanada the opportunity to recover costs of transporting natural gas, including the return of capital (depreciation) and return on the average investment base for each of the Systems. In addition, new facilities are approved by the NEB before construction begins and the NEB regulates the operations of each of the Systems. Net earnings of the Systems may be affected by changes in investment base, the allowed return on equity, and any incentive earnings.

Oil Pipelines

The NEB regulates the terms and conditions of service, including rates, and the physical operation of the Canadian portion of the Keystone system. NEB approval is also required for facility additions. The rates for

transportation service on the Keystone system are calculated in accordance with a methodology agreed to in transportation service agreements between Keystone and its shippers, and approved by the NEB.

United States

Natural Gas Pipelines

TransCanada's wholly owned and partially owned U.S. pipelines, including the ANR, Bison, GTN, Great Lakes, Iroquois, Portland, Northern Border, North Baja and Tuscarora systems, are considered "natural gas companies" operating under the provisions of the *Natural Gas Act of 1938* and the *Natural Gas Policy Act of 1978*, 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 and interstate commerce.

Oil Pipelines

The FERC also regulates the terms and conditions of service, including transportation rates, on the U.S. portion of the Keystone system. Certain states in which Keystone has rights of way also regulate construction and siting of Keystone.

Energy business

The Energy segment of our business includes the acquisition, development, construction, ownership and operation of electrical power generation plants, the purchase and marketing of electricity, the provision of electricity account services to energy and industrial customers, and the development, construction, ownership and operation of non-regulated natural gas storage in Alberta.

The electrical power generation plants and power supply that TransCanada has an interest in, including those under development, in the aggregate, represent more than 10,800 MW of power generation capacity. Power plants and power supply in Canadian power account for approximately 65 per cent of this total, and power plants in U.S. power account for the balance, being approximately 35 per cent.

TransCanada owns and operates the following facilities:

Ravenswood generating station, a 2,480 MW power plant located in Queen's, New York which consists of multiple units employing dual fuel-capable steam turbine, combined-cycle and combustion turbine technology.

Halton Hills, a 683 MW natural gas-fired combined-cycle power plant in Halton Hills, Ontario which is contracted under a 20 year Clean Energy Supply contract with the OPA.

Kibby Wind, a 132 MW wind farm located in the Kibby and Skinner Townships in Maine.

TC Hydro, TransCanada's hydroelectric facilities located in New Hampshire, Vermont and Massachusetts on the Connecticut and Deerfield Rivers, consists of 13 hydroelectric facilities, including stations and associated dams and reservoirs, with a total generating capacity of 583 MW.

Ocean State Power, a 560 MW natural gas-fired, combined-cycle facility in Burrillville, Rhode Island.

Bécancour, a 550 MW natural gas-fired cogeneration power plant located near Trois-Rivières, Québec. The entire power output is supplied to Hydro-Québec which is contracted under a 20 year power purchase agreement expiring in 2026.

Natural gas-fired cogeneration plants in Alberta at Carseland (80 MW), Redwater (40 MW), Bear Creek (80 MW) and MacKay River (165 MW).

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Grandview, a 90 MW natural gas-fired cogeneration power plant located on the site of the Irving Oil Limited oil refinery in Saint John, New Brunswick. Irving Oil Limited is under a 20 year tolling arrangement that expires in 2025, to supply fuel for the plant and to contract 100 per cent of the plant's heat and electricity output.

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Cancarb, a 27 MW facility located in Medicine Hat, Alberta fuelled by waste heat from TransCanada's adjacent thermal carbon black facility.

Edson, an underground natural gas storage facility connected to the Alberta System near Edson, Alberta.

Coolidge, a 575 MW simple-cycle, natural gas-fired peaking power generation station in Arizona. Coolidge, which was placed in service in May 2011, operates under a 20 year power purchase agreement with the Salt River Project Agricultural Improvement and Power District.

TransCanada has the following long-term power purchase arrangements in place:

TransCanada has the rights to 100 per cent of the generating capacity of the 560 MW Sundance A coal-fired power generation facility under a power purchase arrangement that expires in 2017. TransCanada also has a 50 per cent interest in ASTC Power Partnership, which has a power purchase arrangement that expires in 2020, in place for 100 per cent of the production from the 706 MW Sundance B power facility. The Sundance facilities are located in south-central Alberta.

The Sheerness facility, which consists of two coal-fired thermal power generating units, is located in Southeastern Alberta. TransCanada has the rights to 756 MW of generating capacity from the Sheerness power purchase arrangement that expires in 2020.

TransCanada has interests in the following:

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 being refurbished. The two units being refurbished are expected to resume commercial operations in first and third quarter 2012, respectively. Bruce B has four operating reactors with a combined capacity of 3,200 MW. Bruce A subleases Units 1 to 4 from Bruce B, and Bruce B consists of Units 5 to 8. TransCanada owns a 48.8 per cent interest in Bruce A and a 31.6 per cent interest in Bruce B.

A 60 per cent ownership in CrossAlta, which is a 68 Bcf underground natural gas storage facility connected to the Alberta System near Crossfield, Alberta. The facility'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 and, through an agreement made effective July 1, 2011, is now the operator of the facility.

A 62 per cent interest in the Cartier Wind energy project. The Carleton (109 MW), Anse-à-Valleau (101 MW) and Baie-des-Sables (110 MW) commenced commercial operation in November 2008, November 2007 and November 2006, respectively. Montagne-Sèche (58 MW) and the first phase of Gros-Morne (101 MW) commenced commercial operation in November 2011. The second phase of Gros-Morne (111 MW) is expected to be operational in December 2012. All of the power produced by Cartier Wind is sold to Hydro-Québec Distribution under a 20 year power purchase agreement.

Portlands Energy, a 550 MW, combined-cycle natural gas power plant located in Toronto, Ontario, is 50 per cent owned by TransCanada, and is operated by TransCanada under a 20 year Accelerated Clean Energy Supply contract with the OPA.

Further information about the Company's energy holdings and significant developments and opportunities in relation to Energy can be found in the MD&A under the headings *Energy*, *Energy Highlights*, *Energy Financial Analysis* and *Energy Opportunities and Developments*.

General

Employees

At Year End, TransCanada's principal operating subsidiary, TCPL, had approximately 4,300 full time active employees, substantially all of whom were employed in Canada and the U.S., as set forth in the following table.

Calgary	1,955
Western Canada (excluding Calgary)	451
Houston	467
U.S. Midwest	440
U.S. Northeast	403
Eastern Canada	253
U.S. Southeast/Gulf Coast	246
U.S. West Coast	79
Mexico and South America	5
Total	4,299

Social and environmental policies

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

The Health, Safety and Environment Committee of our Board of Directors (the "Board") monitors compliance with the Company's HSE corporate policy through regular reporting. TransCanada's integrated HSE management system is modeled after the International Organization for Standardization standard for environmental management systems, ISO 14001; and the Occupational Health and Safety Assessment Series (OHSAS 18001) for occupational health and safety. Our HSE management system conforms to external industry consensus standards and voluntary regulatory programs and complies with applicable legislated requirements and various other internal management systems. Resources are focused on the areas of significant risk to the organization's HSE business activities. Management is informed regularly of all important and/or significant HSE operational issues and initiatives through formal reporting and incident management processes. TransCanada's HSE management system and performance are assessed by an independent outside firm every three years. The most recent assessment occurred in 2009 and did not identify any material issues. The HSE management system is subject to ongoing internal and external review to ensure that it remains effective as circumstances change.

As one of TransCanada's priorities, safety is an integral part of the way our employees work. In 2011, one of our objectives was to sustain health and safety performance year over year. Overall, TransCanada's safety frequency rates in 2011 continued to be better than most industry benchmarks.

The safety and integrity of our existing and newly-developed infrastructure is also a top priority. All new assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are brought in service only after all necessary requirements have been satisfied. We expect to spend approximately \$322 million in 2012 for pipeline integrity on pipelines we operate, an increase of approximately

\$78 million over 2011 primarily due to increased levels of in-line pipeline inspection on all systems. Under the approved regulatory models in Canada, non-capital pipeline integrity expenditures on our 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 transportation contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, these expenditures have no impact on TransCanada's earnings. Our pipeline safety record in 2011 continued to be better than industry benchmarks. We experienced two pipeline breaks in 2011 on pipelines we operate. The first break occurred in a remote part of Northern Ontario on the Canadian Mainline pipeline system. The second break occurred in a remote part of Wyoming on the Bison pipeline system. Spending associated with public safety on the Energy assets is focused primarily on the Company's hydro dams and associated equipment and is slightly higher than previous years due to increased spending to repair damage from the high flow events of 2011 caused by Hurricane Irene.

Environmental controls including physical design, programs, procedures and processes are in place to effectively manage TransCanada's environmental risk factors. With respect to physical risks arising from climate change, we have in place a set of procedures to manage our response to natural disasters such as forest fires, tornadoes, earthquakes, floods, volcanic eruptions and hurricanes regardless of cause. These procedures are included in TransCanada's Operating Procedures and are part of the Company's Incident Management System. The procedures are in place to protect the health and safety of our employees and to limit the impact to the environment of any operational upsets caused by a natural disaster.

With respect to business opportunities, the Company has well established processes and criteria for assessing new business opportunities including those that may arise as a result of climate change policies. These processes have been and continue to be key contributors to our financial strength and success. Governments in North America are developing long-term plans for limiting greenhouse gas ("GHG") emissions. These plans, combined with a shift in consumer attitude and demand for low-emissions fuels, will require changes in energy supply and infrastructure. With the Company's experience in pipeline transmission and power generation, TransCanada is well-positioned to participate in these opportunities.

Aboriginal, Native American and stakeholder engagement

We recognize that an enhanced level of engagement of a wide variety of stakeholders in our business activities can have a significant impact on the Company's ability to obtain approvals for new assets and to maintain our social licenses to operate. TransCanada has a number of policies, guiding principles and practices in place to help manage stakeholder engagement. TransCanada has adopted a code of business ethics which applies to our employees that is based on the Company's four core values of integrity, collaboration, responsibility and innovation, which guide the interaction between and among the Company's employees and serve as a standard for TransCanada in our dealings with all stakeholders. The code may be viewed on our website (www.transcanada.com).

Our approach to stakeholder engagement is based on building relationships, mutual respect and trust while recognizing the unique values, needs and interests of each community. Key principles that guide TransCanada's engagement include: the Company's respect for the diversity of Aboriginal/Native American communities and recognition of the importance of the land to these communities; and our belief in engaging stakeholders from the earliest stages of our projects, through the project development process and into operations.

Environmental protection

TransCanada's facilities are subject to stringent federal, state, provincial, and local environmental statutes and regulations governing environmental protection, including, but not limited to, air emissions and GHG emissions, water quality, wastewater discharges and waste management. Such laws and regulations generally require facilities to obtain or comply with a wide variety of environmental registrations, licences, permits and other approvals and requirements. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, the imposition of remedial requirements and/or

the issuance of orders respecting future operations. We have ongoing inspection programs designed to keep all of our facilities in compliance with environmental requirements.

At December 31, 2011, TransCanada recorded liabilities of approximately \$69 million (2010 \$84 million) for remediation obligations and compliance costs associated with certain environmental regulations. We believe that the Company has considered all necessary contingencies and established appropriate reserves for environmental liabilities; however, there is the risk that unforeseen matters may arise requiring us 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.

The Company owns assets in four regions, Alberta, Québec, B.C., and the Northeastern U.S., where regulations exist to address industrial GHG emissions. We have procedures in place to comply with these regulations. In Alberta, under the *Specified Gas Emitters Regulation*, industrial facilities emitting GHG emissions over an intensity threshold level are required to reduce the intensity of GHG emissions by 12 per cent below an average baseline. Our Alberta-based facilities are subject to this regulation, as are the Sundance and Sheerness coal-fired power facilities with respect to which TransCanada has certain rights under power purchase arrangements. TransCanada has a program in place to manage the compliance costs incurred by these assets as a result of the regulation. Compliance costs on the Alberta System are recovered through tolls 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 GHG emissions related costs of \$13 million for 2011 (2010 \$22 million), 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 2011, 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 carbon tax in B.C., which came into effect in mid-2008, applies to carbon dioxide ("CO₂") 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 2011 were approximately \$3 million (2010 \$4 million). The cost per tonne of CO₂ will be increased in July 2012 to \$30.00 from \$25.00.

States in the northeastern U.S. that are members of the Regional Greenhouse Gas Initiative ("RGGI") implemented a CO₂ cap-and-trade program for electricity generators effective in January 2009. Under the RGGI, both the Ravenswood and Ocean State Power generation facilities were 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 Ocean State Power generation facilities and incurred related costs of \$4 million in 2011 (2010 \$5 million). These costs were generally recovered through the power market and the net impact on TransCanada was not significant.

Risk factors

Environmental risk factors

Environmental risks

Environmental risks from our operating facilities typically include: air emissions and GHG emissions; potential impacts on land, including land reclamation or restoration following construction; the use, storage and release of hydrocarbons or other chemicals; the generation, handling and disposal of wastes and hazardous wastes; and water impacts such as uncontrolled water discharge.

TransCanada's assets are located throughout North America and the Company's facility design must deal with different geographical areas. In northern regions, changing permafrost distribution due to warmer temperatures have been experienced, however, very few kilometers of our pipeline systems are currently in

permafrost regions. If we build new facilities in northern areas, the Company's facility designs will take into account the potential for changing permafrost distribution.

As mentioned above, our 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 TransCanada 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 contaminated sites or additional information at existing contaminated 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.

Changing legislation and regulations

The impact of new or proposed federal, state, and/or provincial safety and environmental laws, regulations, guidelines and enforcement in Canada and the U.S. on our business is not yet certain. We make assumptions about possible expenditures for 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.

In April 2010, the Environmental Protection Agency ("EPA") published an Advanced Notice of Proposed Rulemaking to solicit comments with respect to EPA reassessment of current regulations under the *Toxic Substances Control Act*, governing the authorized use of polychlorinated biphenyls in certain equipment. Following a review of comments, the EPA has indicated that the use authorization for pipelines will likely remain in place but that requirements to use the authorization may become more strict. These changes would likely result in increased costs for our impacted pipelines. Proposed EPA rules are expected in 2012.

In Canada, development of the major elements of an Air Quality Management System ("AQMS") continued in 2011 following endorsement of the AQMS in October 2010 by the Canadian Council of Ministers of the Environment. Two key aspects of the AQMS are of particular interest to us: the Base Level Industry Emissions Standards, which assumes that all significant industrial sources of emissions in Canada should be expected to meet, base-level of environmental performance; and air zone management, which is intended to address the sources of air pollution and the actions that are required to ensure that a specified level of air quality is improved or maintained in a specified region. While our Canadian based facilities would likely be impacted by AQMS, the potential financial impact of this initiative is currently unknown.

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 enhanced 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, we anticipate additional future costs related to the monitoring and control of air emissions.

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

In August 2011, the Canadian government published the first sector specific draft regulation that will impact industrial GHG emissions. This proposed regulation is focused on the coal-fired generation of electricity and requires a natural gas performance standard for all coal-fired facilities reaching the end of their economic life. The draft regulation is expected to come into effect in July 2015. This process is not expected to pose a significant risk or financial impact to our existing facilities and may present opportunities for new power generation investment. Additional sectors, including the natural gas-fired generation of electricity and upstream oil and gas facility sectors, are expected to begin consultations with Environment Canada.

The Western Climate Initiative ("WCI") continues to work toward implementing a regional cap-and-trade program. California and Québec are the only WCI members with cap-and-trade regulations. In December 2011, the Government of Québec adopted the "Regulation respecting the cap-and-trade system for greenhouse gas emission allowances". The initial phase of the cap-and-trade system will begin January 1, 2013. The regulation will have a limited impact on TransCanada's Bécancour power generation facility and natural gas pipeline assets. With respect to California, the Air Resources Board adopted a cap-and-trade regulation in October 2011. The regulation is divided into two phases: the first, beginning in 2013, will include all major industrial sources and electricity utilities; the second, starting in 2015, will cover distributors of transportation fuels, natural gas and other fuels. The regulation may impact the Company's importation of electricity into the state.

TransCanada monitors climate change policy developments and, when warranted, participates in policy discussions in jurisdictions where we have operations. We are also continuing our programs to manage GHG emissions from our facilities and to evaluate new processes and technologies that result in improved efficiencies and lower GHG emission rates. For example, in 2011 TransCanada participated in a number of multi-stakeholder expert groups that were established to develop equipment standards in Canada. TransCanada participated both independently and through industry associations.

Other risk factors

A discussion of the Company's risk factors can be found in the MD&A under the headings *Natural Gas Pipelines Opportunities and Developments, Natural Gas Pipelines Business Risks, Natural Gas Pipelines Outlook, Oil Pipelines Opportunities and Developments, Oil Pipelines Business Risks, Oil Pipelines Outlook, Energy Opportunities and Developments, Energy Business Risks, Energy Outlook and Risk Management and Financial Instruments*.

Dividends

The Board has not adopted a formal dividend policy. The Board reviews the financial performance of TransCanada quarterly and makes a determination of the appropriate level of dividends to be declared in the following quarter. Currently, TransCanada's payment of dividends is primarily funded from dividends it receives as the sole common shareholder of TCPL. Provisions of various trust indentures and credit arrangements to which TCPL is a party restrict TCPL's ability to declare and pay dividends to TransCanada under certain circumstances and, if such restrictions apply, they may, in turn, have an impact on TransCanada's ability to declare and pay dividends. In the opinion of TransCanada's management, such provisions do not currently restrict or alter TransCanada's ability to declare or pay dividends.

Holders of cumulative redeemable first preferred shares, series 1 ("Series 1 Preferred Shares") are entitled to receive fixed cumulative dividends, at an annual rate of \$1.15 per share, payable quarterly, as and when declared by the Board, for the initial five year period ending December 31, 2014. For the period from issuance on September 30, 2009 to December 31, 2009, dividends in the amount of \$0.29 per share were declared and paid on the Series 1 Preferred Shares. For the period January 1, 2010 to December 31, 2010, dividends in the

amount of \$1.15 per share were declared and paid on the Series 1 Preferred Shares. For the period January 1, 2011 to December 31, 2011, dividends in the amount of \$1.15 per share were declared and paid on the Series 1 Preferred Shares. The dividend on the Series 1 Preferred Shares will reset on December 31, 2014 and every five years thereafter to a rate equal to the sum of the then five year Government of Canada bond yield and 1.92 per cent. The holders of Series 1 Preferred Shares have the right to convert their shares into cumulative redeemable first preferred shares, series 2 (the "Series 2 Preferred Shares") as set out under the heading *First preferred shares* below.

Holders of cumulative redeemable first preferred shares, series 3 ("Series 3 Preferred Shares") are entitled to receive fixed cumulative dividends, at an annual rate of \$1.00 per share, payable quarterly, as and when declared by the Board, for the initial five year period ending June 30, 2015. For the period from issuance on March 11, 2010 to December 31, 2010, dividends in the amount of \$0.80 per share were declared and paid on the Series 3 Preferred Shares. For the period January 1, 2011 to December 31, 2011, dividends in the amount of \$1.00 per share were declared and paid on the Series 3 Preferred Shares. The dividend on the Series 3 Preferred Shares will reset on June 30, 2015 and every five years thereafter to a rate equal to the sum of the then five year Government of Canada bond yield and 1.28 per cent. The holders of Series 3 Preferred Shares have the right to convert their shares into cumulative redeemable first preferred shares, series 4 (the "Series 4 Preferred Shares") as set out under the heading *First preferred shares* below.

Holders of cumulative redeemable first preferred shares, series 5 ("Series 5 Preferred Shares") are entitled to receive fixed cumulative dividends, at an annual rate of \$1.10 per share, payable quarterly, as and when declared by the Board, for the initial five and a half year period ending January 30, 2016. For the period from issuance on June 29, 2010 to December 31, 2010, dividends in the amount of \$0.65 per share were declared and dividends in the amount of \$0.37 per share were paid, on the Series 5 Preferred Shares. For the period January 1, 2011 to December 31, 2011, dividends in the amount of \$1.10 per share were declared and paid on the Series 5 Preferred Shares. The dividend on the Series 5 Preferred Shares will reset on January 30, 2016 and every five years thereafter to a rate equal to the sum of the then five year Government of Canada bond yield and 1.54 per cent. The holders of Series 5 Preferred Shares have the right to convert their shares into cumulative redeemable first preferred shares, series 6 (the "Series 6 Preferred Shares") as set out under the heading *First preferred shares* below.

The dividends declared per common share of TransCanada during the past three completed financial years are set forth in the following table:

	2011	2010	2009
Dividends declared on common shares	\$ 1.68	\$ 1.60	\$ 1.52

Description of capital structure

Share capital

TransCanada's authorized share capital consists of an unlimited number of common shares, of which 703,861,065 were issued and outstanding at Year End, and an unlimited number of first preferred shares and second preferred shares, issuable in series, of which 22,000,000 Series 1 Preferred Shares, 14,000,000 Series 3 Preferred Shares and 14,000,000 Series 5 Preferred Shares are issued and outstanding. The following is a description of the material characteristics of each of these classes of shares.

Common shares

The common shares entitle the holders thereof to one vote per share at all meetings of shareholders, except meetings at which only holders of another specified class of shares are entitled to vote, and, subject to the rights, privileges, restrictions and conditions attaching to the first preferred shares and the second preferred shares, whether as a class or a series, and to any other class or series of shares of TransCanada which rank prior to the common shares, entitle the holders thereof to receive (i) dividends if, as and when declared by the Board out of the assets of TransCanada properly applicable to the payment of the dividends in such amount

and payable at such times and at such place or places as the Board may from time to time determine and (ii) the remaining property of TransCanada upon a dissolution.

TransCanada has a Shareholder Rights Plan (the "SR Plan") that is designed to ensure, to the extent possible, that all shareholders of TransCanada are treated fairly in connection with any take-over bid for the Company. The SR Plan creates a right attaching to each Common Share outstanding and to each Common Share subsequently issued. Each right becomes exercisable ten trading days after a person has acquired, or commences a take-over bid to acquire, 20 per cent or more of the common shares, other than by an acquisition pursuant to a take-over bid permitted under the terms of the SR Plan. Prior to a flip-in event (as described below), each right permits registered holders to purchase from the Company common shares of TransCanada at the exercise price equal to three times the market price of such shares, subject to adjustments and anti-dilution provisions (the "exercise price"). The beneficial acquisition by any person of 20 per cent or more of the common shares, other than by way of a take-over bid permitted under the terms of the SR Plan, is referred to as a "flip-in event". Ten trading days after a flip-in event, each TransCanada right will permit registered holders to receive, upon payment of the exercise price, the number of common shares with an aggregate market price equal to twice the exercise price. The SR Plan was reconfirmed at the 2010 annual and special meeting of shareholders and must be reconfirmed every third annual meeting thereafter.

TransCanada has a Dividend Reinvestment and Share Purchase Plan which permits common and preferred shareholders of TransCanada and preferred shareholders of TCPL, to elect to reinvest their cash dividends in additional common shares of TransCanada. Commencing with dividends declared in April 2011, common shares purchased with reinvested cash dividends were satisfied with shares acquired on the open market at 100 per cent of the weighted average purchase price. Previously, common shares were 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. In February 2012, the Board approved an increase in the quarterly common share dividend payment by 5 per cent to \$0.44 per share from \$0.42 per share, for the quarter ending March 31, 2012. Participants may also make additional cash payments of up to \$10,000 per quarter to purchase additional common shares, which optional purchases are not eligible for any discount on the price of common shares. Participants are not responsible for payment of brokerage commissions or other transaction expenses for purchases made pursuant to the Dividend Reinvestment and Share Purchase Plan.

TransCanada also has stock-based compensation plans (the "SOPs") that allow some employees to purchase common shares of TransCanada. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted under the SOPs are generally fully exercisable after three years and expire seven years after the date of grant.

First preferred shares

Subject to certain limitations, the Board may, from time to time, issue first preferred shares in one or more series and determine for any such series, its designation, number of shares and respective rights, privileges, restrictions and conditions. The first preferred shares as a class have, among others, the provisions described below.

The first preferred shares of each series rank on a parity with the first preferred shares of every other series, and are entitled to preference over the common shares, the second preferred shares and any other shares ranking junior to the first preferred shares with respect to the payment of dividends, the repayment of capital and the distribution of assets of TransCanada in the event of a liquidation, dissolution or winding up of TransCanada.

Except as provided by the CBCA or as referred to below, the holders of the first preferred shares will not have any voting rights nor will they be entitled to receive notice of or to attend shareholders' meetings. The holders of any particular series of first preferred shares will, if the directors so determine prior to the issuance of such series, be entitled to such voting rights as may be determined by the directors if TransCanada fails to pay dividends on that series of preferred shares for any period as may be so determined by the directors.

The provisions attaching to the first preferred shares as a class may be modified, amended or varied only with the approval of the holders of the first preferred shares as a class. Any such approval to be given by the holders of the first preferred shares may be given by the affirmative vote of the holders of not less than sixty-six and two-thirds per cent of the first preferred shares represented and voted at a meeting or adjourned meeting of such holders.

The Series 1 Preferred Shares are entitled to the payment of dividends as set out above under the heading *Dividends*. The Series 1 Preferred Shares are redeemable by TransCanada in whole or in part on or after December 31, 2014, by the payment of an amount in cash for each share to be redeemed equal to \$25.00 plus all accrued and unpaid dividends thereon. The holders of Series 1 Preferred Shares have the right to convert their shares into cumulative redeemable Series 2 Preferred Shares, subject to certain conditions, 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, as and when declared by the Board, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.92 per cent. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 1 Preferred Shares shall be entitled to receive \$25.00 per Series 1 Preferred Share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the Series 1 Preferred Shares.

The Series 3 Preferred Shares are entitled to the payment of dividends as set out above under the heading *Dividends*. The rights, privileges, restrictions and conditions attaching to the Series 3 Preferred Shares are substantially identical to those attaching to the Series 1 Preferred Shares, except as outlined below. The Series 3 Preferred Shares are redeemable by TransCanada in whole or in part on or after June 30, 2015, by the payment of an amount in cash for each share to be redeemed equal to \$25.00 plus all accrued and unpaid dividends thereon. The holders of Series 3 Preferred Shares have the right to convert their shares into cumulative redeemable Series 4 Preferred Shares, subject to certain conditions, 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, as and when declared by the Board, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.28 per cent. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 3 Preferred Shares shall be entitled to receive \$25.00 per Series 3 Preferred Share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the Series 3 Preferred Shares.

The Series 5 Preferred Shares are entitled to the payment of dividends as set out above under the heading *Dividends*. The rights, privileges, restrictions and conditions attaching to the Series 5 Preferred Shares are substantially identical to those attaching to the Series 1 Preferred Shares, except as outlined below. The Series 5 Preferred Shares are redeemable by TransCanada in whole or in part on or after January 30, 2016, by the payment of an amount in cash for each share to be redeemed equal to \$25.00 plus all accrued and unpaid dividends thereon. The holders of Series 5 Preferred Shares have the right to convert their shares into cumulative redeemable Series 6 Preferred Shares, subject to certain conditions, 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, as and when declared by the Board, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.54 per cent. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 5 Preferred Shares shall be entitled to receive \$25.00 per Series 5 Preferred Share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the Series 5 Preferred Shares.

Except as provided by the CBCA, the respective holders of the Series 1, 2, 3, 4, 5 and 6 Preferred Shares are not entitled to receive notice of, attend at, or vote at any meeting of shareholders unless and until TransCanada shall have failed to pay eight quarterly dividends, whether or not consecutive, in which case the respective holders of Series 1, 2, 3, 4, 5 and 6 Preferred Shares shall have the right to receive notice of and to attend each meeting of shareholders at which directors are to be elected and which take place more than 60 days after the date on which the failure first occurs, and to one vote with respect to resolutions to elect directors for each Series 1, 2, 3, 4, 5 and 6 Preferred Share, respectively, until all arrears of dividends have been paid. Subject to the CBCA, the series provisions attaching to the Series 1, 2, 3, 4, 5 or 6 Preferred Shares may be amended with the written approval of all the holders of such series of shares outstanding or by at least two-thirds of the votes cast at a meeting of the holders of such shares duly called for the purpose and at which a quorum is present.

Second preferred shares

The rights, privileges, restrictions and conditions attaching to the second preferred shares are substantially identical to those attaching to the first preferred shares, except that the second preferred shares are junior to the first preferred shares with respect to the payment of dividends, repayment of capital and the distribution of assets of TransCanada in the event of a liquidation, dissolution or winding up of TransCanada.

Credit ratings

Although TransCanada has not issued debt to the public, it has been assigned credit ratings by Moody's Investors Service, Inc. ("Moody's") and Standard & Poor's ("S&P"). Moody's has assigned an issuer rating of Baa1 with a stable outlook and S&P has assigned a long-term corporate credit rating of A- with a stable outlook. TransCanada does not presently intend to issue debt securities to the public in its own name and any future debt financing requirements are expected to continue to be funded primarily through its subsidiary, TCPL. The following table sets out the current credit ratings assigned to those outstanding classes of securities of TCPL which have been rated by DBRS Limited ("DBRS"), Moody's and S&P:

	DBRS	Moody's	S&P
Senior unsecured debt			
<i>Debentures</i>	A	A3	A-
<i>Medium-term notes</i>	A	A3	A-
Junior subordinated notes	BBB (high)	Baa1	BBB
	DBRS	Moody's	S&P
Preferred shares	Pfd-2 (low)	Baa2	P-2
Commercial paper	R-1 (low)	-	A-2
Trending/rating outlook	Stable	Stable	Stable

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. Credit ratings are not recommendations to purchase, hold or sell securities and do not address the market price or suitability of a specific security for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

The Company paid fees to each of DBRS, Moody's and S&P for the credit ratings rendered on each of the outstanding classes of securities noted above. No additional payments were made to DBRS, Moody's and S&P in respect of any other services provided to the Company during the past two years.

The information concerning the Company's credit ratings relates to the Company's financing costs, liquidity and operations. The availability of TransCanada's funding options may be affected by certain factors, including the global capital market environment and outlook as well as the Company's financial performance. TransCanada's access to capital markets at competitive rates is dependent on its credit rating and rating outlook, as determined by credit rating agencies such as DBRS, Moody's and S&P, and if TransCanada's ratings were downgraded the Company's financing costs and future debt issuances could be unfavorably impacted. A description of the rating agencies' credit ratings listed in the table above is set out below.

DBRS Limited (DBRS)

DBRS has different rating scales for short- and long-term debt and preferred shares. "High" or "low" grades are used to indicate the relative standing within all rating categories other than AAA and D. The absence of either a "high" or "low" designation indicates the rating is in the

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"middle" of the category. The R-1 (low) rating assigned to TCPL's short-term debt is in the third highest of ten rating categories and indicates good credit quality. The overall strength is not as favourable as higher rating categories, but any qualifying negative factors that exist are considered manageable. The A rating assigned to TCPL's senior unsecured debt is in the third highest of ten categories for long-term debt. Long-term debt rated A is good credit quality. The capacity

for the payment of interest and principal is substantial, but of lesser credit quality than that of AA rated securities. Long-term debt rated A may be vulnerable to future events but qualifying negative factors are considered manageable. The BBB (high) rating assigned to junior subordinated notes is in the fourth highest of the ten categories for long-term debt. Long-term debt rated BBB is of adequate credit quality. The capacity for the payment of interest and principal is considered acceptable, but it may be vulnerable to future events. The Pfd-2 (low) rating assigned to TCPL's and TransCanada's preferred shares is in the second highest of six rating categories for preferred shares. Preferred shares rated Pfd-2 are of satisfactory credit quality. Protection of dividends and principal is still substantial; however, earnings, the balance sheet and coverage ratios are not as strong as Pfd-1 rated companies. In general, Pfd-2 ratings correspond with long-term debt rated in the A category.

Moody's Investors Service, Inc. (Moody's)

Moody's has different rating scales for short- and long-term obligations. Numerical modifiers 1, 2 and 3 are applied to each rating classification from Aa through Caa, with 1 being the highest and 3 being the lowest. The A3 rating assigned to TCPL's senior unsecured debt is in the third highest of nine rating categories for long-term obligations. Obligations rated A are considered upper medium grade and are subject to low credit risk. The Baa1 and Baa2 ratings assigned to TCPL's junior subordinated debt and preferred shares, respectively, are in the fourth highest of nine rating categories for long-term obligations, with the junior subordinated debt ranking slightly higher within the Baa rating category with a modifier of 1 as opposed to the modifier of 2 on the preferred shares. Obligations rated Baa are subject to moderate credit risk, are considered medium-grade, and as such, may possess certain speculative characteristics.

Standard & Poor's (S&P)

S&P has different rating scales for short- and long-term obligations. Ratings from AA through CCC may be modified by the addition of a plus (+) or minus (-) sign to show the relative standing within a particular rating category. The A- rating assigned to TCPL's senior unsecured debt is in the third highest of ten rating categories for long-term obligations. An A rating indicates the obligor's capacity to meet its financial commitment is strong; however, the obligation is slightly more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rated categories. As guarantor of a U.S. subsidiary's commercial paper program, TCPL has been assigned a commercial paper rating of A-2 which is the second highest of nine rating categories for short-term debt obligations. A short term debt rated A-2 is somewhat more susceptible to adverse effects of changes in economic conditions than higher rated categories; however, the capacity to meet all financial commitments remains satisfactory. The BBB and P-2 ratings assigned to TCPL's junior subordinated notes and TCPL's and TransCanada's preferred shares exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation.

Market for securities

TransCanada's common shares are listed on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") under the symbol "TRP". TransCanada's Series 1 Preferred Shares, Series 3 Preferred Shares and Series 5 Preferred Shares have been listed for trading on the TSX since September 30, 2009, March 11, 2010 and June 29, 2010, under the symbols "TRP.PR.A", "TRP.PR.B", and "TRP.PR.C", respectively. The following tables set forth the reported monthly high, low, and month-end closing trading prices and monthly trading volumes of the common shares of TransCanada on the TSX and the NYSE, and the

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respective Series 1 Preferred Shares, Series 3 Preferred Shares and Series 5 Preferred Shares on the TSX, for the period indicated:

Common shares

Month	TSX (TRP)				NYSE (TRP)			
	High (\$)	Low (\$)	Close (\$)	Volume Traded	High (US\$)	Low (US\$)	Close (US\$)	Volume Traded
December 2011	44.74	42.03	44.53	38,155,545	43.95	40.55	43.67	10,540,577
November 2011	42.90	39.25	42.88	40,551,335	42.54	38.62	41.80	22,065,841
October 2011	44.10	39.81	42.37	41,926,225	44.38	37.58	43.04	15,887,005
September 2011	43.23	40.27	42.54	33,171,287	43.79	39.08	40.49	16,346,869
August 2011	42.36	37.00	42.36	41,333,472	43.20	37.29	43.15	26,402,340
July 2011	42.39	39.42	40.14	32,882,839	44.08	40.66	41.95	8,871,558
June 2011	43.72	41.07	42.35	33,597,026	45.09	41.76	43.84	8,832,316
May 2011	43.48	40.75	43.39	27,895,419	44.97	42.10	44.83	7,444,917
April 2011	40.71	38.95	40.71	24,366,705	43.02	40.37	42.94	7,523,263
March 2011	39.64	37.73	39.31	36,681,641	40.76	37.88	40.53	12,204,704
February 2011	39.19	36.53	39.04	37,966,180	40.32	36.76	40.21	9,750,606
January 2011	38.40	36.10	36.55	32,309,382	38.61	36.12	36.54	8,313,201

Series 1 Preferred Shares

Month	TSX (TRP.PR.A)			
	High (\$)	Low (\$)	Close (\$)	Volume Traded
December 2011	26.50	25.85	26.21	154,033
November 2011	26.38	25.66	26.02	215,475
October 2011	26.05	25.71	25.97	305,469
September 2011	26.32	25.78	25.85	221,164
August 2011	26.28	25.65	25.85	156,599
July 2011	26.20	25.81	26.07	226,612
June 2011	26.24	25.68	25.94	278,119
May 2011	26.25	25.65	25.66	1,207,022
April 2011	26.00	25.70	25.80	172,341
March 2011	26.00	25.40	25.75	282,270
February 2011	26.36	25.40	25.64	479,357
January 2011	26.25	25.75	26.21	601,031

Series 3 Preferred Shares

Month	TSX (TRP.PR.B)			
	High (\$)	Low (\$)	Close (\$)	Volume Traded

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December 2011	25.89	24.94	25.75	165,577
November 2011	25.45	24.97	25.16	359,674
October 2011	25.39	24.96	25.25	350,993
September 2011	25.38	25.00	25.12	221,672
August 2011	25.67	24.81	25.01	278,636
July 2011	25.92	25.15	25.67	501,178
June 2011	25.54	24.93	25.20	343,637
May 2011	25.44	24.85	24.99	326,765
April 2011	25.39	24.93	25.20	328,708
March 2011	25.20	24.42	24.96	389,964
February 2011	25.35	24.36	24.79	336,606
January 2011	25.48	24.70	25.02	499,120

Series 5 Preferred Shares

Month	TSX (TRP.PR.C)			
	High (\$)	Low (\$)	Close (\$)	Volume Traded
December 2011	26.67	25.58	25.80	175,643
November 2011	25.98	25.45	25.84	388,764
October 2011	25.60	25.00	25.49	696,761
September 2011	26.44	25.27	25.46	281,423
August 2011	26.00	25.45	25.77	308,562
July 2011	26.10	25.50	25.88	199,978
June 2011	26.10	25.33	25.56	170,757
May 2011	25.90	25.45	25.80	450,511
April 2011	25.73	25.27	25.52	154,113
March 2011	25.89	25.19	25.73	724,705
February 2011	25.76	25.12	25.39	378,470
January 2011	26.15	25.28	25.49	541,030

In addition, TransCanada's subsidiary, TCPL, has cumulative redeemable first preferred shares, series U and series Y listed on the TSX under the symbols "TCA.PR.X", and "TCA.PR.Y", respectively.

Directors and officers

As of February 13, 2012, the directors and officers of TransCanada as a group beneficially owned, or exercised control or direction, directly or indirectly, over an aggregate of 551,756 common shares of TransCanada. This constitutes less than one per cent of TransCanada's common shares. The Company collects this information from our directors and officers but otherwise we have no direct knowledge of individual holdings of TransCanada's securities.

Directors

The following table sets forth the names of the 14 directors who serve on the Board, as of February 13, 2012, together with their jurisdictions of residence, all positions and offices held by them with TransCanada and the Company's significant affiliates, their principal occupations or employment during the past five years and the year from which each director has continually served as a director of TransCanada and, prior to the arrangement, with TCPL. Positions and offices held with TransCanada are also held by such person at TCPL. Each director holds office until the next annual meeting or until his or her successor is earlier elected or appointed.

Name and place of residence	Principal occupation during the five preceding years	Director since
Kevin E. Benson Calgary, Alberta Canada	President and Chief Executive Officer, Laidlaw International, Inc. (transportation services) from June 2003 to October 2007. Director, Calgary Airport Authority.	2005
Derek H. Burney(1), O.C. Ottawa, Ontario Canada	Senior strategic advisor at Norton Rose Canada LLP (law firm). Chair (not a Director), International Advisory Board for Garda World Consulting and Investigation/Global Risks Group, a division of Garda World Security Corporation since 2008. Chair, Canwest Global Communications Corp. (communications) from	2005

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August 2006 (director since April 2005) to October 2010 and lead director at Shell Canada Limited (oil and gas) from April 2001 to May 2007.

Wendy K. Dobson
Uxbridge, Ontario
Canada

Professor, Rotman School of Management. Director, Institute for International Business, University of Toronto and Director, the Toronto-Dominion Bank. Vice Chair, Canadian Public Accountability Board until February 2010 and Chair of the Audit Committee of the same organization from 2003 to 2009.

1992

Name and place of residence	Principal occupation during the five preceding years	Director since
E. Linn Draper Lampasas, Texas U.S.	Director, Alliance Data Systems Corporation (data processing and services) and Director, Alpha Natural Resources, Inc. (mining). Chair, NorthWestern Corporation (conducting business as NorthWestern Energy) (oil and gas).	2005
The Hon. Paule Gauthier, P.C., O.C., O.Q., Q.C. Québec, Québec Canada	Senior Partner, Stein Monast L.L.P. (law firm). Director, Metro Inc., Royal Bank of Canada, Care Canada and the Fondation du Musée national des beaux-arts du Québec. Director, Institut Québécois des Hautes Études Internationales, Laval University from 2002 until 2009 and RBC Dexia Investors Trust until October 2009.	2002
Russell K. Girling Calgary, Alberta Canada	President and Chief Executive Officer, TransCanada since July 1, 2010. Chief Operating Officer from July 2009 to June 30, 2010 and President, Pipelines from June 2006 to June 30, 2010. Director, Agrium Inc.	2010
S. Barry Jackson Calgary, Alberta Canada	Chair of the Board, TransCanada since April 2005. Director, Nexen Inc. (oil and gas) and Director, WestJet Airlines Ltd. Director Cordero Energy Inc. from April 2005 to September 2008.	2002
Paul L. Joskow New York, New York U.S.	Economist and President of the Alfred P. Sloan Foundation. Professor of Economics, Emeritus, Massachusetts Institute of Technology (MIT) where he has been on the faculty since 1972. Director, Exelon Corporation (energy), and a trustee of Putnam Mutual Funds. Director of the MIT Center for Energy and Environmental Policy Research from 1999 to 2007 and Director of National Grid plc from 2000 to 2007.	2004
John A. MacNaughton(2), C.M. Toronto, Ontario Canada	Chair of the Business Development Bank of Canada. Chair of the Independent Nominating Committee of the Canada Employment Insurance Financing Board since 2008. Member of the Prime Minister's Advisory Committee on the Public Service. Chair, CNSX Markets Inc. (formerly the Canadian Trading and Quotation System Inc.) (stock exchange) from 2006 to July 2010. Director, Nortel Networks Corporation and Nortel Networks Limited (the principal operating subsidiary of Nortel Networks Corporation) (technology) from 2005 to September 2010.	2006
David P. O'Brien(4) Calgary, Alberta Canada	Chair, Encana Corporation (oil and gas) since April 2002 and Chair, Royal Bank of Canada since February 2004. Director, Molson Coors Brewing Company, and Enerplus Corporation. Member of the Science, Technology and	2001

Innovation Council of Canada.

<p>Paula Rospud Reynolds Seattle, Washington U.S.</p>	<p>President and Chief Executive Officer of PreferWest, LLC (business advisory group) since October 2009. Director of Anadarko Petroleum Corporation, Delta Air Lines, Inc. and BAE Systems plc. Vice Chairman and Chief Restructuring Officer of American International Group Inc. (insurance and financial services) from October 2008 to September 2009. President and Chief Executive Officer of Safeco Corporation (insurance) from 2006 to 2008.</p>	<p>2011</p>
<p>W. Thomas Stephens(3) Greenwood Village, Colorado U.S.</p>	<p>Trustee, Putnam Mutual Funds. Chair and Chief Executive Officer of Boise Cascade, LLC (paper, forest products and timberland assets) from November 2004 to November 2008. Director, Boise Inc. from February 2008 until April 2010.</p>	<p>2007(3)</p>
<p>D. Michael G. Stewart Calgary, Alberta Canada</p>	<p>Director, Canadian Energy Services & Technology Corp., Pengrowth Energy Corporation and C&C Energia Ltd. Director, Orleans Energy Ltd. from October 2008 to December 2010. Director, Pengrowth Corporation (the administrator of Pengrowth Energy Trust) from October 2006 to December 2010. Director, Canadian Energy Services Inc. (the general partner of Canadian Energy Services L.P.) from January 2006 to December 2009.</p>	<p>2006</p>
<p>Richard E. Waugh Toronto, Ontario Canada</p>	<p>President and Chief Executive Officer and director of The Bank of Nova Scotia (Scotiabank) since March 2003. Director and President, International Monetary Conference. Vice-Chair, Board of the Institute of International Finance.</p>	<p>2012</p>

- (1) Canwest Global Communications Corp. ("Canwest") voluntarily entered into the Companies' Creditors Arrangement Act ("CCAA") and obtained an order from the Ontario Superior Court of Justice (Commercial Division) to start proceedings on October 6, 2009. Although no cease trade orders were issued, Canwest shares were de-listed by the TSX after the filing and started trading on the TSX Venture Exchange. Canwest emerged from CCAA protection, and Postmedia Network acquired its newspaper business on July 13, 2010 while Shaw Communications Inc. acquired its broadcast media business on October 27, 2010. Mr. Burney ceased to be a director of Canwest on October 27, 2010.
- (2) Nortel Networks Limited was the principal operating subsidiary of Nortel Networks Corporation (collectively referred to as "Nortel"). Mr. MacNaughton became a director of Nortel on June 29, 2005. Nortel was subject to a management cease trade order on April 10, 2006 issued by the Ontario Securities Commission ("OSC") and other provincial securities regulators. The cease trade order related to a delay in filing some of Nortel's 2005 financial statements. The order was revoked by the OSC on June 8, 2006, and the other provincial securities regulators shortly after. On January 14, 2009, Nortel and some of its Canadian subsidiaries filed for creditor protection under CCAA.
- (3) Mr. Stephens previously served on the Board from 2000 to 2005.

(4)

Air Canada filed for protection under the CCAA and applicable bankruptcy protection statutes in the U.S. in April 2003. Mr. O'Brien resigned as a director of Air Canada on November 26, 2003.

Board committees

TransCanada has four committees of the Board: the Audit Committee, the Governance Committee, the Health, Safety and Environment Committee and the Human Resources Committee. The voting members of each of these committees, as of February 13, 2012, are identified below:

Director	Audit Committee	Governance Committee	Health, Safety and Environment Committee	Human Resources Committee
Kevin E. Benson	Chair	ü		
Derek H. Burney	ü	ü		
Wendy K. Dobson			ü	ü
E. Linn Draper	ü		Chair	
Paule Gauthier			ü	ü
S. Barry Jackson		ü		ü
Paul L. Joskow	ü	ü		
John A. MacNaughton	ü	Chair		
David P. O'Brien		ü		ü
Paula Rosput Reynolds			ü	ü
W. Thomas Stephens			ü	Chair
D. Michael G. Stewart	ü		ü	
Richard E. Waugh		ü		

The charters of the Audit Committee, Governance Committee, the Health, Safety and Environment Committee and the Human Resources Committee can be found on our website (www.transcanada.com) under *Corporate Governance Board Committees*. Information about the Audit Committee can be found in this AIF under the heading *Audit Committee*.

Further information about the Board committees and corporate governance can also be found on TransCanada's website.

Officers

All of the executive officers and corporate officers of TransCanada reside in Calgary, Alberta, Canada, with the exception of Mr. Hobbs who resides in Houston, Texas, U.S. References to positions and offices with TransCanada prior to May 15, 2003 are references to the positions and offices held with TCPL. Current positions and offices held with TransCanada are also held by such person at TCPL. As of the date hereof, the

officers of TransCanada, their present positions within TransCanada and their principal occupations during the five preceding years are as follows:

Executive officers

Name	Present position held	Principal occupation during the five preceding years
Russell K. Girling	President and Chief Executive Officer	Prior to July 2010, Chief Operating Officer since July 2009 and President, Pipelines since June 2006. Prior to June 2006, Executive Vice-President and Chief Financial Officer, Corporate Development, since March 2003 and Chief Financial Officer, since August 1999.
Wendy L. Hanrahan(1)	Executive Vice-President, Corporate Services	Prior to May 2011, Vice-President, Human Resources since January 2005.
Gregory A. Lohnes	President, Natural Gas Pipelines	Prior to July 2010, Executive Vice-President and Chief Financial Officer since June 2006.
Donald R. Marchand	Executive Vice-President and Chief Financial Officer	Prior to July 2010, Vice-President, Finance and Treasurer since September 1999.
Dennis J. McConaghy	Executive Vice-President, Corporate Development	Prior to July 2010, Executive Vice-President, Pipeline Strategy and Development.
Sean McMaster	Executive Vice-President, General Counsel and Chief Compliance Officer, and Executive Vice-President, Stakeholder Relations	Prior to February 2012, Executive Vice-President, Corporate and General Counsel and Chief Compliance Officer. Prior to January 2007, Executive Vice-President and General Counsel and Chief Compliance Officer. Prior to October 2006, General Counsel and Chief Compliance Officer.
Alexander J. Pourbaix	President, Energy and Oil Pipelines	President, Energy from July 2006 to July 2010 and Executive Vice-President, Corporate Development from July 2009 to July 2010.
Donald M. Wishart	Executive Vice-President, Operations and Major Projects	Prior to July 2009, Executive Vice-President, Operations and Engineering since March 2003.

(1)

Ms. Hanrahan has held the position of Executive Vice-President, Corporate Services since May 1, 2011, upon the retirement of Ms. Sarah Raiss who had held the position since January 2002.

Corporate officers

Name	Present position held	Principal occupation during the five preceding years
Sean M. Brett	Vice-President and Treasurer	Prior to July 2010, Vice-President, Commercial Operations of TC PipeLines GP, Inc., and Director, LP Operations of TCPL. Prior to December 2009, Director, Joint Venture Management, Keystone Pipeline Project of TCPL. Prior to December 2008, Vice-President and Treasurer of TC PipeLines GP, Inc.
Ronald L. Cook	Vice-President, Taxation	Vice-President, Taxation since April 2002.
Donald J. DeGrandis	Vice-President and Corporate Secretary	Prior to February 2009, Corporate Secretary since June 2006.
Lee G. Hobbs	President, U.S. Natural Gas Pipelines	Senior Vice-President and General Manager, U.S. Pipelines, Pipelines Division, TCPL, June 2009 to July 2010. Vice-President and General Manager, U.S. Pipelines Central, Pipelines Division, TCPL, March 2007 to June 2009. President, Great Lakes Gas Transmission Company and Great Lakes Gas Transmission Limited Partnership, September 2006 to March 2007.
Joel E. Hunter	Vice-President, Finance	Director, Corporate Finance, January 2008 to July 2010. Prior to January 2008, Senior Analyst, Corporate Finance. Prior to January 2007 Mr. Hunter held a number of positions of increasing responsibility with TransCanada's Finance and Treasury Group.
Garry E. Lamb	Vice-President, Risk Management	Vice-President, Risk Management since October 2001.
G. Glenn Menuz	Vice-President and Controller	Vice-President and Controller since June 2006.

Conflicts of interest

Directors and officers of TransCanada and its subsidiaries are required to disclose the existence of existing or potential conflicts in accordance with TransCanada policies governing directors and officers and in accordance with the CBCA. Although some of the directors sit on boards or may be otherwise associated with companies that ship natural gas on TransCanada's pipeline systems, TransCanada, as a common carrier in Canada, cannot, under our tariff, deny transportation service to a creditworthy shipper. Further, due to the specialized nature of the industry,

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TransCanada believes that it is important for our Board to be composed of qualified and knowledgeable directors, so some of them must come from the oil and gas producer and shipper community; the Governance Committee monitors relationships among directors to ensure that business associations do not affect the Board's performance. In a circumstance where a director declares an interest in any material contract or material transaction being considered at a meeting, the director generally absents himself or herself from the meeting during the consideration of the matter, and does not vote on the matter.

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Corporate governance

Our Board and management are committed to the highest standards of ethical conduct and corporate governance.

TransCanada is a public company listed on the TSX and the NYSE, and we recognize and respect rules and regulations in both Canada and the U.S.

Our corporate governance practices comply with the Canadian governance guidelines, which include the governance rules of the Canadian Securities Administrators ("CSA"):

National Instrument 52-110, *Audit Committees* (Canadian audit committee rules)

National Policy 58-201, *Corporate Governance Guidelines*, and

National Instrument 58-101, *Disclosure of Corporate Governance Practices*.

We also comply with the governance listing standards of the NYSE and the governance rules of the SEC that apply to foreign private issuers.

Our governance practices comply with the NYSE standards for U.S. companies in all significant respects, except as summarized on our website (www.transcanada.com). As a non-U.S. company, we are not required to comply with most of the governance listing standards of the NYSE. As a foreign private issuer, however, we must disclose how our governance practices differ from those followed by U.S. companies that are subject to the NYSE standards.

We benchmark our policies and procedures against major North American companies to assess our standards and we adopt best practices as appropriate. Some of our best practices are derived from the NYSE rules and comply with applicable rules adopted by the SEC to meet the requirements of the *Sarbanes-Oxley Act of 2002* and the *Dodd-Frank Wall Street Reform and Consumer Protection Act*.

Further information about TransCanada's corporate governance can be found on our website (www.transcanada.com) under the heading *Corporate Governance* and in the *Governance* section of TransCanada's Management Information Circular dated February 13, 2012.

Audit committee

The Audit Committee is responsible for assisting the Board in overseeing the integrity of our financial statements and our compliance with legal and regulatory requirements. It is also responsible for overseeing and monitoring the internal accounting and reporting process and the process, performance and independence of our internal and external auditors. The Charter of the Audit Committee can be found in Schedule B of this AIF and on our website (www.transcanada.com) under the *Corporate Governance Board Committees* page.

Relevant education and experience of members

The members of the Audit Committee as of February 13, 2012 are Kevin E. Benson (Chair), Derek H. Burney, E. Linn Draper, Paul L. Joskow, John A. MacNaughton, and D. Michael G. Stewart.

The Board believes that the composition of the Audit Committee reflects a high level of financial literacy and expertise. Each member of the Audit Committee has been determined by the Board to be "independent" and "financially literate" within the meaning of the definitions under Canadian and U.S. securities laws and the NYSE rules. In addition, the Board has determined that Mr. Benson is an "Audit Committee Financial Expert" as that term is defined under U.S. securities laws. The Board has made these determinations based on the education and breadth and depth of experience of each member of the Audit Committee. The following is a description of the education and experience, apart from their respective roles as directors of TransCanada, of each member of the Audit Committee that is relevant to the performance of his responsibilities as a member of the Audit Committee.

Kevin E. Benson

Mr. Benson earned a Bachelor of Accounting from the University of Witwatersrand (South Africa) and was a member of the South African Society of Chartered Accountants. Mr. Benson was the President and Chief Executive Officer of Laidlaw International, Inc. until October 2007. In prior years, he has held several executive positions including one as President and Chief Executive Officer of The Insurance Corporation of British Columbia and has served on other public company boards and on the audit committees of certain of those boards.

Derek H. Burney

Mr. Burney earned a Bachelor of Arts (Honours) and Master of Arts from Queen's University. He is currently a senior strategic advisor at Norton Rose Canada LLP. Mr. Burney previously served as President and Chief Executive Officer of CAE Inc. and as Chair and Chief Executive Officer of Bell Canada International Inc. Mr. Burney was the lead director at Shell Canada Limited until May 2007 and was the Chair of Canwest Global Communications Corp. until October 2010. He has served on one other organization's audit committee, and has participated in Financial Reporting Standards Training offered by KPMG.

E. Linn Draper

Dr. Draper holds a Bachelor of Science in Chemical Engineering from Rice University and a Ph.D. in Nuclear Science and Engineering from Cornell University. Dr. Draper was Chair, President and Chief Executive Officer of American Electric Power Co., Inc. until 2004. He previously served as Chair, President and Chief Executive Officer of Gulf States Utilities Company. Dr. Draper has served and continues to serve on several other public company boards.

Paul L. Joskow

Mr. Joskow earned a Bachelor of Arts with Distinction in Economics from Cornell University, a Masters of Philosophy in Economics from Yale University, and a Ph.D. in Economics from Yale University. He is currently the President of the Alfred P. Sloan Foundation and a Professor of Economics, Emeritus, at MIT. He has served on the boards of several public companies and other organizations and on the audit committees of certain of those boards.

John A. MacNaughton

Mr. MacNaughton earned a Bachelor of Arts in Economics from the University of Western Ontario. Mr. MacNaughton is currently the Chair of the Business Development Bank of Canada, and was Chair of CNSX Markets Inc. (formerly Canadian Trading and Quotation System Inc.) until July 2010. In prior years, he has held several executive positions including founding President and Chief Executive Officer of the Canadian Pension Plan Investment Board and President of Nesbitt Burns Inc. He has served on the audit committee of other public companies.

D. Michael G. Stewart

Mr. Stewart earned a Bachelor of Science (Honours) in Geological Science from Queen's University. Mr. Stewart has served and continues to serve on the boards of several public companies and other organizations and on the audit committees of certain of those boards. Mr. Stewart held a number of senior executive positions with Westcoast Energy Inc. including Executive Vice-President, Business Development. He has been active in the Canadian energy industry for over 38 years.

Pre-approval policies and procedures

TransCanada's Audit Committee has adopted a pre-approval policy with respect to permitted non-audit services. Under the policy, the Audit Committee has granted pre-approval for specified non-audit services. For engagements of \$25,000 or less which are not within the annual pre-approved limit, approval by the Audit Committee is not required, and for engagements between \$25,000 and \$100,000, approval of the Audit

Committee Chair is required, and the Audit Committee is to be informed of the engagement at the next scheduled Audit Committee meeting. For all engagements of \$100,000 or more, pre-approval of the Audit Committee is required. In all cases, regardless of the dollar amount involved, where there is a potential for conflict of interest involving the external auditor to arise on an engagement, the Audit Committee Chair must pre-approve the assignment.

To date, TransCanada has not approved any non-audit services on the basis of the de-minimus exemptions. All non-audit services have been pre-approved by the Audit Committee in accordance with the pre-approval policy described above.

External auditor service fees

The following table provides information about the fees paid by the Company to KPMG LLP, the external auditor of the TransCanada group of companies, for professional services rendered for the 2011 and 2010 fiscal years.

(\$ millions)	2011	2010
Audit fees		
audit of the annual consolidated financial statements		
services related to statutory and regulatory filings or engagements		
reviewing interim consolidated financial statements and information contained in various prospectuses and other offering documents	\$ 6.9	\$ 6.5
Audit-related fees		
services related to the audit of the financial statements of certain TransCanada pension plans	0.2	0.2
Tax fees		
Canadian and international tax planning and tax compliance matters, including the review of income tax returns and other tax filings	0.4	1.0
All other fees		
services related to environmental compliance in 2011 and advice and training related to International Financial Reporting Standards in 2010	0.1	0.2
Total fees	\$ 7.6	\$ 7.9

Legal proceedings and regulatory actions

TransCanada and its subsidiaries are subject to various legal proceedings and regulatory actions arising in the normal course of business. While the final outcome of such legal proceedings and regulatory actions cannot be predicted with certainty and there can be no assurance that such matters will be resolved in TransCanada's favour, it is the opinion of TransCanada's management that the resolution of such proceedings and regulatory actions will not have a material impact on TransCanada's consolidated financial position, results of operations or liquidity.

The Company believes that TransAlta's claims with respect to Sundance A do not meet the test of force majeure or destruction as specified in the power purchase arrangement and has therefore recorded revenues and costs throughout 2011 under the power purchase arrangement as though this event was an interruption of supply. While the outcome of any arbitration process is not certain, TransCanada believes the matter will be resolved in its favour.

Further information about the Sundance arbitration can be found in this AIF under the heading *Developments in the Energy Business* and in the MD&A under the heading *Energy Opportunities and Developments*.

Transfer agent and registrar

TransCanada's transfer agent and registrar is Computershare Trust Company of Canada with its Canadian transfer facilities in the cities of Vancouver, Calgary, Toronto, and Montréal.

Interest of experts

TransCanada's auditors, KPMG LLP, have confirmed that they are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

Additional information

1. Additional information in relation to TransCanada may be found under TransCanada's profile on SEDAR (www.sedar.com).
2. Additional information including directors' and officers' remuneration and indebtedness, principal holders of TransCanada's securities and securities authorized for issuance under equity compensation plans (all where applicable), is contained in TransCanada's management information circular for its most recent annual meeting of shareholders that involved the election of directors and can be obtained upon request from the Corporate Secretary of TransCanada.
3. Additional financial information is provided in TransCanada's audited consolidated financial statements and MD&A for its most recently completed financial year.

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Glossary

AIF	Annual Information Form of TransCanada Corporation dated February 13, 2012
AQMS	Air Quality Management System
Alaska Pipeline	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.
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, Indiana and Ohio, and regulated underground natural gas storage facilities in Michigan
B.C.	British Columbia
BPRIA	Bruce Power Refurbishment Implementation Agreement
Bcf	Billion cubic feet
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
Board	TransCanada's Board of Directors
Bruce A	A partnership interest in a nuclear power generation facility consisting of Units 1 to 4 of Bruce Power (Bruce Power A L.P.)
Bruce B	A partnership interest in a nuclear power generation facility consisting of Units 5 to 8 of Bruce Power (Bruce Power L.P.)
Bruce Power	A nuclear power generating facility located northwest of Toronto, Ontario (Bruce A and Bruce B, collectively)
Canadian Mainline	A natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec
Canwest	Canwest Global Communications Corp.
Cartier Wind	Five wind farms in Gaspé, Québec, four plus the first phase of the fifth which are operational and phase two of the fifth under construction
CBCA	<i>Canada Business Corporations Act</i>
CCAA	<i>Companies' Creditors Arrangement Act</i>
CO ₂	Carbon dioxide
Coolidge	A simple-cycle, natural gas-fired peaking power generation station in Coolidge, Arizona
CSA	Canadian Securities Administrators
Cushing Extension	A crude oil pipeline extending from Steele City, Nebraska to Cushing, Oklahoma
DBRS	DBRS Limited
Energy	As defined in this AIF under the heading <i>General development of the business</i>
EPA	Environmental Protection Agency (U.S.)
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
GHG	Greenhouse gas
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.
GTN	A natural gas transmission system extending from the B.C./Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon

Guadalajara	A natural gas pipeline in Mexico extending from Manzanillo, Colima to Guadalajara, Jalisco
Halton Hills	A natural gas-fired, combined-cycle power plant in Halton Hills, Ontario
HSE	Health, safety and environment
Hydro-Québec	Hydro-Québec Distribution
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.
Keystone	A crude oil pipeline system which extends from Hardisty, Alberta to the U.S. markets and includes Wood River/Patoka and the Cushing Extension
Keystone XL	Keystone XL includes the construction of a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast, the expansion of existing facilities at Hardisty, Alberta and the construction of a new crude oil pipeline from Hardisty to Steele City, Nebraska
Kibby Wind	A wind farm located in Kibby and Skinner townships in northwestern Franklin County, Maine
km	Kilometer(s)
Mackenzie Gas Project	A proposed natural gas pipeline extending from a point near Inuvik, Northwest Territories to the northern border of Alberta
MD&A	TransCanada's Management's Discussion and Analysis dated February 13, 2012
MMcf/d	Million cubic feet per day
Moody's	Moody's Investors Service, Inc.
MW	Megawatt(s)
Natural Gas Pipelines	As defined in this AIF under the heading <i>General development of the business</i>
NEB	National Energy Board
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
NGTL	Nova Gas Transmission Ltd.
Nortel	Nortel Networks Limited and Nortel Networks Corporation, collectively
NYISO	New York Independent System Operator
NYSE	New York Stock Exchange
Ocean State Power	A natural gas-fired, combined-cycle plant in Burrillville, Rhode Island
Oil Pipelines	As defined in this AIF under the heading <i>General development of the business</i>
OPA	Ontario Power Authority
OSC	Ontario Securities Commission
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
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
Restructuring Proposal	Canadian Mainline 2012 Tolls Application and Restructuring Proposal
RGGI	Regional Greenhouse Gas Initiative
S&P	Standard & Poor's
SEC	U.S. Securities and Exchange Commission
Series 1 Preferred Shares	TransCanada's cumulative, redeemable, first preferred shares, series 1
Series 2 Preferred Shares	TransCanada's cumulative, redeemable, first preferred shares, series 2

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Series 3 Preferred Shares	TransCanada's cumulative, redeemable, first preferred shares, series 3
Series 4 Preferred Shares	TransCanada's cumulative, redeemable, first preferred shares, series 4
Series 5 Preferred Shares	TransCanada's cumulative, redeemable, first preferred shares, series 5
Series 6 Preferred Shares	TransCanada's cumulative, redeemable, first preferred shares, series 6
Sheerness	A coal-fired power generating facility near Hanna, Alberta
SOPs	TransCanada's stock-based compensation plans
SR Plan	TransCanada's Shareholder Rights Plan
subsidiary	As defined in this AIF under the heading <i>Presentation of information</i>
Sundance	Two coal-fired power generating facilities near Wabamun, Alberta (Sundance A and Sundance B, collectively)
Systems	As defined in this AIF under the heading <i>Regulation of the Natural Gas and Oil Pipelines businesses</i>
TCPL	TransCanada PipeLines Limited
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
TransCanada or the Company	TransCanada Corporation
TransAlta	TransAlta Corporation
TSX	Toronto Stock Exchange
Tuscarora	A natural gas transmission system extending from Malin, Oregon to Wadsworth, Nevada
U.S. or US	United States
U.S. GAAP	U.S. generally accepted accounting principles
WCI	Western Climate Initiative
Wood River/Patoka	A crude oil pipeline extending from Hardisty, Alberta to U.S. Markets at Wood River and Patoka in Illinois
Year End	December 31, 2011

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Schedule A**Metric Conversion Table**

The conversion factors set out below are approximate factors. To convert from Metric to Imperial multiply by the factor indicated. To convert from Imperial to Metric divide by the factor indicated.

Metric	Imperial	Factor
Kilometres (km)	Miles	0.62
Millimetres	Inches	0.04
Gigajoules	Million British thermal units	0.95
Cubic metres*	Cubic feet	35.3
Kilopascals	Pounds per square inch	0.15
Degrees Celsius	Degrees Fahrenheit	to convert to Fahrenheit multiply by 1.8, then add 32 degrees; to convert to Celsius subtract 32 degrees, then divide by 1.8

*

The conversion is based on natural gas at a base pressure of 101.325 kilopascals and at a base temperature of 15 degrees Celsius.

Schedule B
Charter of the Audit Committee

1. Purpose

The Audit Committee shall assist the Board of Directors (the "Board") in overseeing and monitoring, among other things, the:

Company's financial accounting and reporting process;

integrity of the financial statements

Company's internal control over financial reporting;

external financial audit process;

compliance by the Company with legal and regulatory requirements; and

independence and performance of the Company's internal and external auditors.

To fulfill its purpose, the Audit Committee has been delegated certain authorities by the Board of Directors that it may exercise on behalf of the Board.

2. Roles and Responsibilities

I.

Appointment of the Company's External Auditors

Subject to confirmation by the external auditors of their compliance with Canadian and U.S. regulatory registration requirements, the Audit Committee shall recommend to the Board the appointment of the external auditors, such appointment to be confirmed by the Company's shareholders at each annual meeting. The Audit Committee shall also recommend to the Board the compensation to be paid to the external auditors for audit services and shall pre-approve the retention of the external auditors for any permitted non-audit service and the fees for such service. The Audit Committee shall also be directly responsible for the oversight of the work of the external auditor (including resolution of disagreements between management and the external auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or related work. The external auditor shall report directly to the Audit Committee.

The Audit Committee shall also receive periodic reports from the external auditors regarding the auditors' independence, discuss such reports with the auditors, consider whether the provision of non-audit services is compatible with maintaining the auditors' independence and the Audit Committee shall take appropriate action to satisfy itself of the independence of the external auditors.

II.

Oversight in Respect of Financial Disclosure

The Audit Committee, to the extent it deems it necessary or appropriate, shall:

(a)

review, discuss with management and the external auditors and recommend to the Board for approval, the Company's audited annual financial statements, annual information form including management discussion and analysis, all financial statements in prospectuses and other offering memoranda, financial statements required by regulatory authorities, all prospectuses and all documents which may be incorporated by reference into a prospectus, including without limitation, the annual proxy circular, but excluding any pricing supplements issued under a medium term note prospectus supplement of the Company;

- (b) review, discuss with management and the external auditors and recommend to the Board for approval the release to the public of the Company's interim reports, including the financial statements, management discussion and analysis and press releases on quarterly financial results;
 - (c) review and discuss with management and external auditors the use of "pro forma" or "adjusted" non-GAAP information and the applicable reconciliation;
-

- (d) review and discuss with management and external auditors financial information and earnings guidance provided to analysts and rating agencies; provided, however, that such discussion may be done generally (consisting of discussing the types of information to be disclosed and the types of presentations to be made). The Audit Committee need not discuss in advance each instance in which the Company may provide earnings guidance or presentations to rating agencies;
- (e) review with management and the external auditors major issues regarding accounting and auditing principles and practices, including any significant changes in the Company's selection or application of accounting principles, as well as major issues as to the adequacy of the Company's internal controls and any special audit steps adopted in light of material control deficiencies that could significantly affect the Company's financial statements;
- (f) review and discuss quarterly reports from the external auditors on:
 - (i) all critical accounting policies and practices to be used;
 - (ii) all alternative treatments of financial information within generally accepted accounting principles that have been discussed with management, ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditor;
 - (iii) other material written communications between the external auditor and management, such as any management letter or schedule of unadjusted differences;
- (g) review with management and the external auditors the effect of regulatory and accounting initiatives as well as off-balance sheet structures on the Company's financial statements;
- (h) review with management, the external auditors and, if necessary, legal counsel, any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Company, and the manner in which these matters have been disclosed in the financial statements;
- (i) review disclosures made to the Audit Committee by the Company's CEO and CFO during their certification process for the periodic reports filed with securities regulators about any significant deficiencies in the design or operation of internal controls or material weaknesses therein and any fraud involving management or other employees who have a significant role in the Company's internal controls;
- (j) discuss with management the Company's material financial risk exposures and the steps management has taken to monitor and control such exposures, including the Company's risk assessment and risk management policies;

III.

Oversight in Respect of Legal and Regulatory Matters

- (a) review with the Company's General Counsel legal matters that may have a material impact on the financial statements, the Company's compliance policies and any material reports or inquiries received from regulators or governmental agencies.

IV.

Oversight in Respect of Internal Audit

- (a) review the audit plans of the internal auditors of the Company including the degree of coordination between such plan and that of the external auditors and the extent to which the planned audit scope can be relied upon to detect weaknesses in internal control, fraud or other illegal acts;
- (b)

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review the significant findings prepared by the internal auditing department and recommendations issued by the Company or by any external party relating to internal audit issues, together with management's response thereto;

(c)

review compliance with the Company's policies and avoidance of conflicts of interest;

(d)

review the adequacy of the resources of the internal auditor to ensure the objectivity and independence of the internal audit function, including reports from the internal audit department on its audit process with associates and affiliates;

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- (e) ensure the internal auditor has access to the Chair of the Audit Committee and of the Board and to the Chief Executive Officer and meet separately with the internal auditor to review with him any problems or difficulties he may have encountered and specifically:
 - (i) any difficulties which were encountered in the course of the audit work, including restrictions on the scope of activities or access to required information, and any disagreements with management;
 - (ii) any changes required in the planned scope of the internal audit; and
 - (iii) the internal audit department responsibilities, budget and staffing;and to report to the Board on such meetings;

V.

Insight in Respect of the External Auditors

- (a) review the annual post-audit or management letter from the external auditors and management's response and follow-up in respect of any identified weakness, inquire regularly of management and the external auditors of any significant issues between them and how they have been resolved, and intervene in the resolution if required;
- (b) review the quarterly unaudited financial statements with the external auditors and receive and review the review engagement reports of external auditors on unaudited financial statements of the Company;
- (c) receive and review annually the external auditors' formal written statement of independence delineating all relationships between itself and the Company;
- (d) meet separately with the external auditors to review with them any problems or difficulties the external auditors may have encountered and specifically:
 - (i) any difficulties which were encountered in the course of the audit work, including any restrictions on the scope of activities or access to required information, and any disagreements with management; and
 - (ii) any changes required in the planned scope of the audit;

and to report to the Board on such meetings;

- (e) review with the external auditors the adequacy and appropriateness of the accounting policies used in preparation of the financial statements;
- (f) meet with the external auditors prior to the audit to review the planning and staffing of the audit;
- (g) receive and review annually the external auditors' written report on their own internal quality control procedures; any material issues raised by the most recent internal quality control review, or peer review, of the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, and any steps taken to deal with such issues;
- (h) review and evaluate the external auditors, including the lead partner of the external auditor team;

- (i) ensure the rotation of the lead (or coordinating) audit partner having primary responsibility for the audit and the audit partner responsible for reviewing the audit as required by law, but at least every five years;

VI.

Oversight in Respect of Audit and Non-Audit Services

- (a) pre-approve all audit services (which may entail providing comfort letters in connection with securities underwritings) and all permitted non-audit services, other than non-audit services where:
 - (i) the aggregate amount of all such non-audit services provided to the Company constitutes not more than 5% of the total fees paid by the Company and its subsidiaries to the external auditor during the fiscal year in which the non-audit services are provided;

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- (ii) such services were not recognized by the Company at the time of the engagement to be non-audit services; and
- (iii) such services are promptly brought to the attention of the Audit Committee and approved prior to the completion of the audit by the Audit Committee or by one or more members of the Audit Committee to whom authority to grant such approvals has been delegated by the Audit Committee;

- (b) approval by the Audit Committee of a non-audit service to be performed by the external auditor shall be disclosed as required under securities laws and regulations;
- (c) the Audit Committee may delegate to one or more designated members of the Audit Committee the authority to grant pre-approvals required by this subsection. The decisions of any member to whom authority is delegated to pre-approve an activity shall be presented to the Audit Committee at its first scheduled meeting following such pre-approval;
- (d) if the Audit Committee approves an audit service within the scope of the engagement of the external auditor, such audit service shall be deemed to have been pre-approved for purposes of this subsection;

VII.

Oversight in Respect of Certain Policies

- (a) review and recommend to the Board for approval the implementation and amendments to policies and program initiatives deemed advisable by management or the Audit Committee with respect to the Company's codes of business ethics and Risk Management and Financial Reporting policies;
- (b) obtain reports from management, the Company's senior internal auditing executive and the external auditors and report to the Board on the status and adequacy of the Company's efforts to ensure its businesses are conducted and its facilities are operated in an ethical, legally compliant and socially responsible manner, in accordance with the Company's codes of business conduct and ethics;
- (c) establish a non-traceable, confidential and anonymous system by which callers may ask for advice or report any ethical or financial concern, ensure that procedures for the receipt, retention and treatment of complaints in respect of accounting, internal controls and auditing matters are in place, and receive reports on such matters as necessary;
- (d) annually review and assess the adequacy of the Company's public disclosure policy;
- (e) review and approve the Company's hiring policies for partners, employees and former partners and employees of the present and former external auditors (recognizing the Sarbanes-Oxley Act of 2002 does not permit the CEO, controller, CFO or chief accounting officer to have participated in the Company's audit as an employee of the external auditors' during the preceding one-year period) and monitor the Company's adherence to the policy;

VIII.

Oversight in Respect of Financial Aspects of the Company's Canadian Pension Plans (the "Company's pension plans"), specifically:

- (a) provide advice to the Human Resources Committee on any proposed changes in the Company's pension plans in respect of any significant effect such changes may have on pension financial matters;
- (b) review and consider financial and investment reports and the funded status relating to the Company's pension plans and recommend to the Board on pension contributions;
- (c)

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receive, review and report to the Board on the actuarial valuation and funding requirements for the Company's pension plans;

- (d) review and approve annually the Statement of Investment Policies and Procedures ("SIP&P");
- (e) approve the appointment or termination of auditors and investment managers;

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IX.

Oversight in Respect of Internal Administration

- (a) review annually the reports of the Company's representatives on certain audit committees of subsidiaries and affiliates of the Company and any significant issues and auditor recommendations concerning such subsidiaries and affiliates;
- (b) review the succession plans in respect of the Chief Financial Officer, the Vice President, Risk Management and the Director, Internal Audit;
- (c) review and approve the policy and guidelines for the Company's hiring of partners, employees and former partners and employees of the external auditors who were engaged on the Company's account;

X.

Oversight Function

While the Audit Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Audit Committee to plan or conduct audits or to determine that the Company's financial statements and disclosures are complete and accurate or are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibilities of management and the external auditors. The Audit Committee, its Chair and any of its members who have accounting or related financial management experience or expertise, are members of the Board, appointed to the Audit Committee to provide broad oversight of the financial disclosure, financial risk and control related activities of the Company, and are specifically not accountable nor responsible for the day to day operation of such activities. Although designation of a member or members as an "audit committee financial expert" is based on that individual's education and experience, which that individual will bring to bear in carrying out his or her duties on the Audit Committee, designation as an "audit committee financial expert" does not impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the Audit Committee and Board in the absence of such designation. Rather, the role of any audit committee financial expert, like the role of all Audit Committee members, is to oversee the process and not to certify or guarantee the internal or external audit of the Company's financial information or public disclosure.

3. Composition of Audit Committee

The Audit Committee shall consist of three or more Directors, a majority of whom are resident Canadians (as defined in the Canada Business Corporations Act), and all of whom are unrelated and/or independent for the purposes of applicable Canadian and United States securities law and applicable rules of any stock exchange on which the Company's shares are listed. Each member of the Audit Committee shall be financially literate and at least one member shall have accounting or related financial management expertise (as those terms are defined from time to time under the requirements or guidelines for audit committee service under securities laws and the applicable rules of any stock exchange on which the Company's securities are listed for trading or, if it is not so defined as that term is interpreted by the Board in its business judgment).

4. Appointment of Audit Committee Members

The members of the Audit Committee shall be appointed by the Board from time to time, on the recommendation of the Governance Committee and shall hold office until the next annual meeting of shareholders or until their successors are earlier appointed or until they cease to be Directors of the Company.

5. Vacancies

Where a vacancy occurs at any time in the membership of the Audit Committee, it may be filled by the Board on the recommendation of the Governance Committee.

6. Audit Committee Chair

The Board shall appoint a Chair of the Audit Committee who shall:

- (a) review and approve the agenda for each meeting of the Audit Committee and as appropriate, consult with members of management;
- (b) preside over meetings of the Audit Committee;
- (c) make suggestions and provide feedback from the Audit Committee to management regarding information that is or should be provided to the Audit Committee;
- (d) report to the Board on the activities of the Audit Committee relative to its recommendations, resolutions, actions and concerns; and
- (e) meet as necessary with the internal and external auditors.

7. Absence of Audit Committee Chair

If the Chair of the Audit Committee is not present at any meeting of the Audit Committee, one of the other members of the Audit Committee present at the meeting shall be chosen by the Audit Committee to preside at the meeting.

8. Secretary of Audit Committee

The Corporate Secretary shall act as Secretary to the Audit Committee.

9. Meetings

The Chair, or any two members of the Audit Committee, or the internal auditor, or the external auditors, may call a meeting of the Audit Committee. The Audit Committee shall meet at least quarterly. The Audit Committee shall meet periodically with management, the internal auditors and the external auditors in separate executive sessions.

10. Quorum

A majority of the members of the Audit Committee, present in person or by telephone or other telecommunication device that permit all persons participating in the meeting to speak to each other, shall constitute a quorum.

11. Notice of Meetings

Notice of the time and place of every meeting shall be given in writing or facsimile communication to each member of the Audit Committee at least 24 hours prior to the time fixed for such meeting; provided, however, that a member may in any manner waive a notice of a meeting. Attendance of a member at a meeting is a waiver of notice of the meeting, except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting is not lawfully called.

12. Attendance of Company Officers and Employees at Meeting

At the invitation of the Chair of the Audit Committee, one or more officers or employees of the Company may attend any meeting of the Audit Committee.

13. Procedure, Records and Reporting

The Audit Committee shall fix its own procedure at meetings, keep records of its proceedings and report to the Board when the Audit Committee may deem appropriate but not later than the next meeting of the Board.

14. Review of Charter and Evaluation of Audit Committee

The Audit Committee shall review its Charter annually or otherwise, as it deems appropriate, and if necessary propose changes to the Governance Committee and the Board. The Audit Committee shall annually review the Audit Committee's own performance.

15. Outside Experts and Advisors

The Audit Committee is authorized, when deemed necessary or desirable, to retain and set and pay the compensation for independent counsel, outside experts and other advisors, at the Company's expense, to advise the Audit Committee or its members independently on any matter.

16. Reliance

Absent actual knowledge to the contrary (which shall be promptly reported to the Board), each member of the Audit Committee shall be entitled to rely on (i) the integrity of those persons or organizations within and outside the Company from which it receives information, (ii) the accuracy of the financial and other information provided to the Audit Committee by such persons or organizations and (iii) representations made by Management and the external auditors, as to any information technology, internal audit and other non-audit services provided by the external auditors to the Company and its subsidiaries.

Financial Highlights

<i>Year ended December 31</i>					
<i>(millions of dollars)</i>					
	2011	2010	2009	2008	2007
Income					
Net income attributable to common shares	1,527	1,227	1,374	1,440	1,223
Cash Flow					
Funds generated from operations	3,663	3,331	3,080	3,021	2,621
Decrease/(increase) in operating working capital	310	(249)	(90)	135	63
Net cash provided by operations	3,973	3,082	2,990	3,156	2,684
Capital expenditures and acquisitions	3,274	5,036	6,319	6,363	5,874
Balance Sheet					
Total assets	48,995	46,794	43,841	39,414	30,330
Long-term debt	17,632	17,028	16,186	15,368	12,377
Junior subordinated notes	1,009	985	1,036	1,213	975
Preferred shares	1,224	1,224	539		
Common shareholders' equity	16,100	15,503	15,220	12,898	9,785
<i>Common Share Statistics</i>					
<i>Year ended December 31</i>					
	2011	2010	2009	2008	2007
Net income per common share					
basic	\$2.18	\$1.78	\$2.11	\$2.53	\$2.31
diluted	\$2.17	\$1.77	\$2.11	\$2.52	\$2.30
Dividends declared per common share	\$1.68	\$1.60	\$1.52	\$1.44	\$1.36
Common shares outstanding (millions)					
Average for the year	701.6	690.5	651.8	569.6	529.9
End of year	703.9	696.2	684.4	616.5	539.8

TRANSCANADA CORPORATION **1**

Chairman's Message

2011 was a strong year at TransCanada. We continue to experience the financial benefits of bringing \$10 billion of assets into service since the spring of 2010. That progress will continue through 2012, with the completion of other major projects such as the re-start of two reactors at the Bruce nuclear facility.

Looking forward, we expect to invest an additional \$12 billion in projects by the end of 2014 or early 2015. This will cap one of the largest capital programs in Canadian corporate history. TransCanada is widely recognized as a leader in the safe and reliable operation of North American energy infrastructure. It is known as a company that delivers on its promises and takes its responsibility toward all stakeholders seriously.

Notwithstanding that reputation, in 2011 the company became known by many for something more – the Keystone XL pipeline. Project opponents have used the pipeline as a lightning rod for a debate on society's use of fossil fuels, and specifically, Alberta's oil sands production. Seeing Keystone XL attacked in the media has been trying for our Board and for all TransCanada employees who take pride in the work they accomplish each and every day. The company has taken every opportunity to discuss the merits of the project in a factual, professional manner.

Experts forecast oil will be needed for decades and Keystone XL offers Americans an opportunity to receive a stable, secure supply of oil from domestic U.S. and Canadian production. This project makes sense, it has our full support and we remain confident it will ultimately be approved.

Our Board continues to be pleased with the transition of leadership at TransCanada from Hal Kvisle to Russ Girling. Russ's focus has remained on the strategies that he helped develop and have made the company successful in the past. He and the executive team have more than met the challenges the past year has presented and we expect that sets the stage for a great future.

Interestingly, our Board will also see noticeable transition between now and 2014. Six of our current directors will reach retirement age and leave the company over that period. The first two such individuals are Wendy Dobson and David O'Brien. Along with my fellow Board members, I would like to thank them for their many years of dedicated service to the company and our shareholders.

The overall scope of this renewal is unprecedented in TransCanada's history and I believe we will attract strong, new talent to provide the guidance and leadership necessary to move the company forward. After an extensive search, the Governance Committee nominated Paula Rosput Reynolds and Richard Waugh to be appointed to the Board.

I am confident Ms. Reynolds and Mr. Waugh, along with TransCanada's 4,400 employees, will continue to rise to the challenges ahead and build future successes for the company, to the benefit of our shareholders, partners and stakeholders.

On behalf of the Board of Directors;

S. Barry Jackson

2 CHAIRMAN'S MESSAGE

Letter to Shareholders

Building and operating safe and reliable energy infrastructure it is what we do and we do it well. Millions of people across North America rely on the energy we deliver every day, to heat their homes, cook their food and fuel their vehicles. We have done this successfully and responsibly for six decades. Our \$49 billion of blue chip assets are essential to North Americans and we are well positioned to continue to meet the continent's growing energy needs for decades to come.

In 2011, TransCanada continued to successfully advance many of its strategic initiatives. While we experienced some disappointments, it is clear our strategy is working and we are seeing very tangible results of our discipline and focus. Our Company delivered a record \$4.8 billion of EBITDA⁽¹⁾ (earnings before interest, taxes, depreciation and amortization) in 2011 versus \$3.9 billion in 2010. This represents a year-over-year increase of \$865 million. This growth in EBITDA⁽¹⁾ translated into comparable net income of \$1.6 billion or \$2.23 per share, a 13 per cent increase over 2010 earnings of \$1.97 per share.

As a result of visible growth in cash flow and earnings, our Board of Directors again increased our annual dividend on our common shares in February 2012 by eight cents, an increase of five per cent. Since 2000, our dividend has risen steadily from 80 cents per share to \$1.76 per share today, an average annual increase of seven per cent. We understand the value our shareholders place on a strong and growing dividend. Going forward, our goal is to continue to increase dividends in conjunction with sustainable growth in cash flow and earnings.

I would like to share with you some of the highlights of 2011, some of our challenges and the bright future we are building for your company. Our base businesses all continued to perform well in 2011 delivering predictable and steady contributions. We captured significant new shale gas supply in Western Canada, Marcellus in the eastern United States (U.S.) and gas from south central U.S. Our power business performed exceptionally well, primarily in the West, where we were well positioned to take advantage of tightening reserve margins and rising prices against a backdrop of robust growth in demand.

In February 2011, our Keystone pipeline system began oil deliveries to Cushing, Oklahoma. Since the start-up of first deliveries to Patoka and Wood River, Illinois in July 2010, Keystone has safely transported over 170 million barrels of Canadian oil to U.S. markets. TransCanada began recording EBITDA⁽¹⁾ from Keystone in February 2011 and over the 11-month period it contributed nearly \$600 million.

(1) Non-GAAP measure that does not have any standardized meaning prescribed by generally accepted accounting principles (GAAP). For more information, see Non-GAAP Measures in the Management's Discussion and Analysis of the 2011 Annual Report.

We continued to successfully advance our large capital program in 2011. Over the past 18 months, we have brought into operation \$10 billion of new projects. These were largely completed on time, within budget and with minimal work-related injury. The projects include the first two phases of Keystone, North Central Corridor, Groundbirch, Halton Hills, Coolidge, Kibby, additional phases of Cartier, Bison and Guadalajara.

Doing all of this safely and without injury is an imperative. The safety of our employees, contractors and the public is our first priority. In this same time period, our employees and contractors worked 25 million hours and we experienced a 20 per cent decline in our injury frequency rates, which continue to be among the lowest in our industry. While we are proud of this accomplishment, we know that we must continually

improve our processes and procedures to ensure every employee and contractor goes home safe every day period.

We experienced some start-up issues on both the Keystone and Bison pipelines in 2011. Our teams responded well, confirming the effectiveness of our emergency response capabilities, which worked as planned, and the capacity of the company to ensure public safety, protect the environment, repair facilities and return to service safely delivering the energy people need. This proven capability is truly a competitive advantage in a business that is increasingly in the public eye with ever rising standards of conduct. We embrace the challenge of continually improving our performance.

The Canadian Mainline remains a critical component of the North American natural gas pipeline network. That being said, the Mainline is being used differently as a result of the significant changes that have occurred in natural gas supply, demand and transportation in North America. In order to address those changes, we filed a comprehensive proposal with our regulator in 2011 to significantly reduce tolls and restructure services in a way that will enhance the competitiveness of the Mainline and the Western Canada Sedimentary Basin.

On Keystone XL, we remain focused on gaining approval for the US\$7 billion project and proceeding with construction. A Final Environmental Impact Statement (FEIS) was issued in August 2011 that concluded the pipeline would have minimal impact on the environment.

On January 18, 2012, the State Department denied a Presidential Permit for Keystone XL. The decision was not based on the merits of the pipeline but rather that legislation introduced by Congress in December 2011, effectively to accelerate approval, did not allow for sufficient time to complete the required review. The State Department indicated that TransCanada can re-apply for a permit.

We are obviously very disappointed with the decision; however, TransCanada remains fully committed to the construction of Keystone XL. Plans are underway on a number of fronts to largely maintain the construction schedule. We will re-apply for a Presidential Permit and expect, given the already completed environmental work and supportive FEIS, a new application would be processed in an expedited manner to allow for an in-service date of late 2014/early 2015.

Shipper support for the project remains strong. In 2011, we signed long-term shipping contracts on Keystone XL to transport U.S.-produced oil to market from the Bakken formation in Montana and North Dakota and from Cushing, Oklahoma. In addition, we signed sufficient long-term contracts to support a new lateral pipeline to the large refining hub in Houston, Texas. These projects amount to a US\$800 million incremental investment and increase the capacity of Keystone XL to 830,000 barrels per day. Today, the vast majority of Keystone's overall capacity is reserved with long-term, firm contracts clear evidence of the market need for the pipeline.

In 2011, we made great progress on the Bruce Power refurbishment project with refuelling of both units and beginning the commissioning phase. Our current forecast is for Unit 2 to be fully operational in first quarter 2012 and Unit 1 fully operational in third quarter 2012. When back in service, these two units will deliver 1,500 MW of emissionless energy for the residents of Ontario for decades to come and produce very attractive and stable returns for our shareholders.

We took our first step into solar generation in 2011, with the \$470 million acquisition of nine projects. This is a fast growing segment of the power market and I would expect several new opportunities to present themselves in the coming years.

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As we bring an additional \$12 billion of contracted assets into service over the next three years, we are positioned to deliver substantial growth in cash flow, earnings and dividends through 2015. Over the longer term, there will be significant opportunities to reinvest in our core businesses of natural gas pipelines and storage, oil pipelines and power infrastructure.

The International Energy Agency predicts investment in energy infrastructure of over \$6 trillion will be needed in North America between 2010 and 2035. More specifically, an investment of about \$3 trillion in power, \$2 trillion in natural gas and \$1.5 trillion in oil is required. That infrastructure is needed to fuel a growing economy and to replace aging assets with new and safe oil and gas pipelines and cleaner, more efficient power plants.

Today, we have a \$50 billion portfolio of energy infrastructure projects being evaluated by a very capable business development team. They are focused on meeting the need to move shale and conventional gas within the continent and from frontier regions; attach growing crude oil production to key refining centres; and develop new power generation as the North American market revitalizes its aging infrastructure and evolves to a less carbon-intensive mix. These opportunities mesh extremely well with TransCanada's strategy, growth aspirations, existing presence and deep organizational capabilities.

While we don't expect to capture all of these opportunities, I am confident that these projects, combined with appropriate acquisitions, will provide us with the opportunity to continue to reinvest our substantial discretionary cash flow and grow the company for decades to come.

We will continue to face challenges that is nothing new. Our 4,400 very highly skilled employees are experts in turning challenge into opportunity. I am extremely proud of their achievements in 2011 and the pride and care they take in operating this company they are the reason for our success. I recognize that being in the media spotlight placed an additional burden on all of our employees this year and again I am proud of their value-driven, professional management of all issues that came their way. I thank them for their efforts this year and congratulate them on an outstanding job.

Going forward, I am confident in our strategy, our people and our assets. We will realize our vision of being the leading North American energy infrastructure company. In the process, we will continue to grow cash flow, earnings and dividends and build long-term sustainable value for our shareholders. I thank you for your continued support.

Russell K. Girling
President and Chief Executive Officer

LETTER TO SHAREHOLDERS 5

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This Management's Discussion and Analysis (MD&A) dated February 13, 2012 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, 2011 which are prepared in accordance with Canadian generally accepted accounting principles as defined in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook (CGAAP). This MD&A covers TransCanada's financial position and operations as at and for the year ended December 31, 2011. "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 2011 Annual Report.

TRANSCANADA OVERVIEW

With more than 60 years experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and oil pipelines, power generation and natural gas storage facilities.

Today, TransCanada is:

One of the largest natural gas transmission companies in North America with a network of wholly- and partially-owned natural gas pipelines extending more than 68,500 kilometres (km) (42,500 miles), tapping into virtually all major gas supply basins;

One of the continent's largest providers of natural gas storage and related services with approximately 380 billion cubic feet (Bcf) of storage capacity;

The largest private sector power company in Canada and owns or has interests in over 10,800 megawatts (MW) of power generation in Canada and the United States (U.S.); and

A significant player in the oil transmission business with the start up of the Keystone oil pipeline system and the large expansion opportunity to the U.S. Gulf Coast (Keystone XL).

In pursuing its vision to be the leading energy infrastructure company in North America, TransCanada continually strives to execute a large portfolio of attractive growth projects. Each of these new projects are large scale, long life assets supported by strong business fundamentals and long-term contracts that provide attractive and sustainable returns to shareholders over a long-term time horizon.

With assets of approximately \$49 billion and a substantial growth portfolio, TransCanada believes it is well positioned to build on its track record of strong and sustainable earnings, cash flow and dividends. Since the spring of 2010, TransCanada has brought \$10 billion of growth projects in service and is positioned to complete another \$12 billion of new projects by the end of 2014.

TransCanada's 2011 Key Developments

The Company advanced its significant entry into the oil pipelines transmission business:

Achieved full commercial operations in February 2011 on the sections of the Keystone crude oil pipeline system, extending from Hardisty, Alberta to Wood River and Patoka in Illinois (Wood River/Patoka) and from Steele City, Nebraska, to Cushing, Oklahoma (Cushing Extension) and recorded earnings before interest, taxes, depreciation and amortization (EBITDA) of \$0.6 billion in Keystone's first eleven months of operations;

Received a favourable Final Environmental Impact Statement (FEIS) in August from the U.S. Department of State (DOS) for Keystone XL;

Secured commercial support for an extension and expansion of Keystone XL to provide crude oil transportation service from Hardisty, Alberta to Houston, Texas; and

Received notice that the DOS had denied the Presidential Permit for Keystone XL, based on the DOS's position that it did not have sufficient time to receive and review additional information necessary to assess alternative routes that

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would avoid the Sandhills region of Nebraska. TransCanada will submit a revised Presidential Permit application to the DOS.

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:

Continued to advance pipeline development projects on the Alberta System to transport new natural gas supply from the Horn River and Montney shale basins in northeastern British Columbia (B.C.) as well as the Deep Basin in Alberta:

Received approval from the National Energy Board (NEB) for the construction of natural gas pipeline projects on the Alberta System with capital costs totalling approximately \$910 million including the \$275 million Horn River pipeline; and

Filed additional pipeline development projects with the NEB costing approximately \$810 million that included new agreements to further extend the Horn River pipeline by approximately 100 km (62 miles) at an estimated cost of \$230 million.

Placed in service:

The US\$630 million Bison pipeline in January 2011, which delivers natural gas from the Powder River Basin in Wyoming to an interconnection with the Northern Border Pipeline; and

The US\$360 million Guadalajara pipeline in June 2011, which transports natural gas from Manzanillo to Guadalajara in Mexico.

Filed a comprehensive application, with the NEB in September 2011, to change the business structure and the terms and conditions of service for the Canadian Mainline to address tolls for 2012 and 2013;

Closed the sale of a 25 per cent interest in each of Gas Transmission Northwest LLC (GTN LLC) and Bison Pipeline LLC (Bison LLC) to TC PipeLines, LP for an aggregate purchase price of US\$605 million, which included US\$81 million or 25 per cent of GTN LLC debt outstanding; and

Filed a supplemental application with the NEB to construct \$130 million of new pipeline infrastructure on the Canadian Mainline to receive Marcellus shale basin natural gas from the U.S. at the Niagara Falls receipt point for further transportation to Eastern markets.

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

Placed in service the US\$500 million Coolidge generation station in May 2011, capable of producing 575 MW;

Completed construction and placed in service the Montagne-Sèche and phase one of the Gros-Morne wind farms in November 2011, capable of producing 159 MW of renewable energy;

Executed an agreement in December 2011 for the purchase of nine Ontario solar projects, with a combined capacity of 86 MW, for approximately \$470 million that are expected to come into service between late 2012 and mid-2013; and

Continued to progress the \$4.8 billion refurbishment and restart of two reactors at the Bruce Power nuclear facility in Ontario. TransCanada's expected net capital cost of the project is \$2.4 billion. Fuelling of both Unit 1 and Unit 2 has now been completed and the final phases of commissioning for Unit 2 are underway. Subject to regulatory approval, Bruce Power expects to commence commercial operations of Unit 2 in first quarter 2012 and commercial operations of Unit 1 in third quarter 2012.

The following are other key developments in Energy in 2012.

Both units at Sundance A were not operational throughout 2011 and have been subject to force majeure and economic destruction claims by the asset owner. TransCanada has recorded revenues and costs throughout 2011 as it considers this event to be an interruption of supply in accordance with the terms of the power purchase arrangement (PPA). An arbitration hearing is scheduled for April 2012 to hear both claims.

Since July 2011, spot prices for capacity sales applicable to Ravenswood have been negatively impacted by the manner in which New York Independent System Operator (NYISO) has applied pricing rules for a new power plant in the New York City Zone J market. TransCanada has filed formal complaints with the Federal Energy Regulatory Commission (FERC) that are pending.

TransCanada reached a formal agreement to use an arbitration process to settle the Oakville contract dispute resulting from the termination of a 20-year Clean Energy Supply contract with the Ontario Power Authority (OPA).

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, a master 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 57,000 km (35,500 miles) of wholly owned natural gas pipelines, and more than 11,500 km (7,000 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 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 include regulated natural gas storage facilities in Michigan with a total capacity of 250 Bcf.

TransCanada is also pursuing additional natural gas pipeline projects to diversify both the supply and market sides of this business and add incremental value to existing assets. Key areas of focus include greenfield development opportunities that connect TransCanada's natural gas pipelines to emerging Canadian and U.S. shale gas and other supplies and that play a critical role in satisfying increased natural gas demand in North America especially for power generation. TransCanada continues to advance 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

The Company's Keystone crude oil pipeline system currently operates on the Wood River/Patoka and the Cushing Extension sections and has a nominal design capacity of 591,000 barrels per day (bbl/d). 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, combined with growing demand for secure, reliable sources of energy, TransCanada has identified additional opportunities to develop new oil pipeline capacity.

The Company plans to expand and extend the existing system through Keystone XL which includes the construction of a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast, the addition of operational storage facilities at Hardisty, Alberta and the construction of a new crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska. The expanded oil pipeline system is collectively referred to as Keystone. The completion of Keystone XL is expected to increase total system capacity to approximately 1.4 million bbl/d.

Energy

TransCanada's Energy segment 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, wind and solar assets. TransCanada's power business is primarily located in Canada in Alberta, Ontario and Québec, in the northeastern U.S. mainly in the New England states and New York, and in Arizona. The assets are largely underpinned by long-term tolling contracts or represent low-cost baseload generation and essential capacity.

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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 the Natural Gas Pipelines segment, 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:

Maximize the full-life value of TransCanada's infrastructure assets and commercial positions

Commercially develop and physically execute new asset investment programs

Cultivate a focused portfolio of high-quality development options

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 existing assets and commercial positions. The Company's pipeline assets include large-scale natural gas and crude oil pipelines that connect long-life supply basins with stable and growing markets, generating predictable and sustainable cash flows and earnings. In Energy, highly efficient, large-scale power generation facilities supply power 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, hydro-power, and solar generating facilities demonstrate the Company's commitment to clean, sustainable energy. Long-life infrastructure assets and long-term commercial arrangements are expected to 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 influence the quality of projects, notably the current \$12 billion capital program. These projects are expected to 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 set-up and delivery. It also requires expert regulatory, legal and financing support, as well as outstanding operational set-up. TransCanada's model for managing construction risks and maximizing capital productivity helps ensure disciplined attention to quality, cost and schedule that produces superior service for its customers and quality returns to shareholders. Many of these functional capabilities also create the basis for successful acquisition and integration of new energy and pipeline facilities, an important dimension of the 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 and Northern Canada, as well as 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 in Montana and North Dakota, to preferred North American markets. The Company will continue to assess energy infrastructure acquisition opportunities that complement its existing pipeline network and provide access to new supply and market regions. In Energy, 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 reputable and creditworthy counterparties. Selected opportunities will be advanced 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. At the core of the Company's competitive advantage are powerful capabilities in strategy development, implementation, and continuous improvement. The Company relies on its scale, presence, operating capabilities, leadership and teams to compete effectively and deliver outstanding value to customers. A disciplined approach to capital investment combined with access to sizeable amounts of competitive-cost capital allows the Company to create significant 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. TransCanada values its reputation for consistent financial performance and long-term financial stability. The Company clearly communicates its financial performance to equity and debt investors, providing insight into both value upside and business risks. We work to sustain the trust and support of our long-term investors and to attract new investors who see long-term value in our disciplined approach to the energy infrastructure business. The Company continues to identify and build on all aspects of competitive strength.

CONSOLIDATED FINANCIAL REVIEW**SELECTED THREE-YEAR CONSOLIDATED FINANCIAL DATA**

<i>(millions of dollars except per share amounts)</i>	2011	2010	2009
Income Statement			
Revenues	9,139	8,064	8,181
Comparable EBITDA ⁽¹⁾	4,806	3,941	4,107
Net Income Attributable to Common Shares	1,527	1,227	1,374
Comparable Earnings ⁽¹⁾	1,565	1,361	1,325
Per Share Data			
Net Income per Common Share			
Basic	\$2.18	\$1.78	\$2.11
Diluted	\$2.17	\$1.77	\$2.11
Comparable Earnings per Common Share ⁽¹⁾	\$2.23	\$1.97	\$2.03
Dividends Declared			
Per Common Share	\$1.68	\$1.60	\$1.52
Per Series 1 Preferred Share ⁽²⁾	\$1.15	\$1.15	\$0.29
Per Series 3 Preferred Share ⁽²⁾	\$1.00	\$0.80	
Per Series 5 Preferred Share ⁽²⁾	\$1.10	\$0.65	
Cash Flows			
Funds Generated from Operations ⁽¹⁾	3,663	3,331	3,080
Decrease/(Increase) in Operating Working Capital	310	(249)	(90)
Net Cash Provided by Operations	3,973	3,082	2,990
Capital Expenditures	3,274	5,036	5,417
Acquisitions, Net of Cash Acquired			902
Balance Sheet			
Total Assets	48,995	46,794	43,841
Total Long-Term Liabilities	24,326	23,220	21,959

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

(2) The Company issued Series 1, 3 and 5 preferred shares in September 2009, March 2010 and June 2010, respectively, rounded to nearest cent.

HIGHLIGHTS

Earnings

Net Income Attributable to Common Shares was \$1.5 billion or \$2.18 per share in 2011 compared to \$1.2 billion or \$1.78 per share, respectively, in 2010.

TransCanada's Comparable Earnings in 2011 were \$1.6 billion or \$2.23 per share, a 13 per cent increase on a per share basis compared to the \$1.4 billion or \$1.97 per share reported in 2010.

Cash Flow

Funds Generated from Operations were \$3.7 billion in 2011, an increase of \$0.4 billion or 10 per cent from \$3.3 billion in 2010.

TransCanada invested \$3.3 billion in its Natural Gas Pipelines, Oil Pipelines and Energy capital projects in 2011, including the following:

capital expenditures of \$0.9 billion for Natural Gas Pipelines projects, including expansion of the Alberta System and completion of Bison and Guadalajara;

capital expenditures of \$1.2 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, completion of Coolidge and construction of Cartier Wind, including completion of Montagne-Sèche and phase one of the Gros-Morne project.

In 2011, TransCanada issued approximately \$1.6 billion of long-term debt and \$200 million of common shares, primarily comprising the following:

in December 2011, TC PipeLines, LP made a draw of US\$300 million on its senior revolving credit facility;

in November 2011, the issuance of \$750 million of medium-term notes;

in June 2011, TC PipeLines, LP issued US\$350 million of senior notes; and

in accordance with its Dividend Reinvestment and Share Purchase Plan (DRP), the issuance of approximately 5 million common shares from treasury in lieu of making cash dividend payments totalling \$202 million.

Balance Sheet

Total assets increased by \$2.2 billion to \$49.0 billion in 2011 from 2010, primarily due to investments in capital projects, described above.

TransCanada's Equity Attributable to Controlling Interests increased by \$0.6 billion to \$17.3 billion in 2011 from 2010.

Dividends

On February 13, 2012, the Board of Directors of TransCanada increased the quarterly dividend on the Company's outstanding common shares by five per cent to \$0.44 per share from \$0.42 per share for the quarter ending March 31, 2012. This was the twelfth 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, 2012, and \$0.275 per Series 5 preferred share for the three-month period ending April 30, 2012.

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

Reconciliation of Non-GAAP Measures

Year ended December 31, 2011 <i>(millions of dollars)</i>	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	2,967	587	1,338	(86)	4,806
Depreciation and amortization	(986)	(130)	(398)	(14)	(1,528)
Comparable EBIT	1,981	457	940	(100)	3,278
Other Income Statement Items					
Comparable interest expense					(939)
Interest expense of joint ventures					(55)
Comparable interest income and other					60
Comparable income taxes					(595)
Net income attributable to non-controlling interests					(129)
Preferred share dividends					(55)
Comparable Earnings					1,565
Specific items (net of tax):					
Risk management activities ⁽¹⁾					(38)
Net Income Attributable to Common Shares					1,527

Year ended December 31, 2011*(millions of dollars except per share amounts)*

	2011
Comparable Interest Expense	(939)
Specific item:	
Risk management activities ⁽¹⁾	2
Interest Expense	(937)
Comparable Interest Income and Other	60
Specific item:	
Risk management activities ⁽¹⁾	(5)
Interest Income and Other	55
Comparable Income Taxes	(595)
Specific item:	
Risk management activities ⁽¹⁾	22
Income Taxes Expense	(573)
Comparable Earnings per Common Share	\$2.23
Specific item (net of tax):	
Risk management activities ⁽¹⁾	(0.05)
Net Income per Common Share	\$2.18

Reconciliation of Non-GAAP MeasuresYear ended December 31,
2010*(millions of dollars)*

	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	2,915		1,125	(99)	3,941
Depreciation and amortization	(977)		(377)		(1,354)
Comparable EBIT	1,938		748	(99)	2,587

**Other Income Statement
Items**

Comparable interest expense					(701)
Interest expense of joint ventures					(59)
Comparable interest income and other					94
Comparable income taxes					(400)
Net income attributable to non-controlling interests					(115)
Preferred share dividends					(45)

Comparable Earnings

Specific items (net of tax):					1,361
Valuation provision for MGP					(127)
Risk management activities ⁽¹⁾					(7)

**Net Income Attributable to Common
Shares**

1,227

Year ended December 31, 2010*(millions of dollars except per share amounts)***2010****Comparable Income Taxes**

(400)

Specific items:

Valuation provision for MGP	19
Risk management activities ⁽¹⁾	1

Income Taxes Expense

(380)

Comparable Earnings per Common Share

\$1.97

Specific items:

Valuation provision for MGP	(0.18)
Risk management activities ⁽¹⁾	(0.01)

Net Income per Common Share

\$1.78

Reconciliation of Non-GAAP Measures

Year ended December 31, 2009 (millions of dollars)	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	3,093		1,131	(117)	4,107
Depreciation and amortization	(1,030)		(347)		(1,377)
Comparable EBIT	2,063		784	(117)	2,730

Other Income Statement Items

Comparable interest expense					(954)
Interest expense of joint ventures					(64)
Comparable interest income and other					121
Comparable income taxes					(406)
Net income attributable to non-controlling interests					(96)
Preferred share dividends					(6)

Comparable Earnings

Comparable Earnings					1,325
Specific items (net of tax):					
Dilution gain from reduced interest in TC PipeLines, LP					18
Risk management activities ⁽¹⁾					1
Income tax adjustments					30

Net Income Attributable to Common Shares

1,374

Year ended December 31, 2009

(millions of dollars except per share amounts)

2009**Comparable Income Taxes**

(406)

Specific items:

Dilution gain from reduced interest in TC PipeLines, LP					(11)
Income tax adjustments					30

Income Taxes Expense

(387)

Comparable Earnings per Common Share

\$2.03

Specific items:

Dilution gain from reduced interest in TC PipeLines, LP					0.03
Risk management activities ⁽¹⁾					
Income tax adjustments					0.05

Net Income per Common Share

\$2.11

⁽¹⁾ For the year ended (millions of dollars)**2011**

2010

2009

Risk Management Activities Gains/(Losses):

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U.S. Power derivatives	(48)	2	
Canadian Power derivatives	(3)		
Natural Gas Storage proprietary inventory and derivatives	(6)	(10)	1
Interest rate derivatives	2		
Foreign exchange derivatives	(5)		
Income taxes attributable to risk management activities	22	1	
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Risk Management Activities	(38)	(7)	1
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RESULTS OF OPERATIONS

TransCanada had Net Income Attributable to Common Shares of \$1,527 million or \$2.18 per share in 2011 compared to \$1,227 million or \$1.78 per share and \$1,374 million or \$2.11 per share in 2010 and 2009, respectively.

Comparable Earnings in 2011, 2010 and 2009 were \$1,565 million or \$2.23 per share, \$1,361 million or \$1.97 per share and \$1,325 million or \$2.03 per share, respectively. Comparable Earnings in 2011 excluded \$38 million of net unrealized after-tax losses (\$60 million pre-tax) resulting from changes in the fair value of certain risk management activities.

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 Mackenzie Gas Project (MGP) and \$7 million of net unrealized after-tax losses (\$8 million pre-tax) resulting from changes in the fair value of certain risk management activities.

Comparable Earnings in 2009 excluded \$30 million of favourable income tax adjustments arising from a reduction in the Province of Ontario's corporate income tax rates, an \$18 million after-tax (\$29 million pre-tax) dilution gain resulting from TransCanada's reduced interest in TC PipeLines, LP following a public offering of TC PipeLines, LP common units in fourth quarter 2009 and a \$1 million net unrealized after-tax gain (\$1 million pre-tax) resulting from changes in the fair value of certain risk management activities.

Comparable Earnings increased \$204 million or \$0.26 per share in 2011 compared to 2010 and included the following:

increased Comparable Earnings Before Interest and Taxes (EBIT) from Natural Gas Pipelines primarily due to incremental earnings from Bison and Guadalajara which were placed in service in January 2011 and June 2011, respectively, lower general, administrative and support costs as well as lower business development spending, partially offset by lower revenues from certain U.S. Pipelines and the negative impact of a weaker U.S. dollar;

Oil Pipelines Comparable EBIT as the Company commenced recording earnings from Keystone in February 2011;

increased Comparable EBIT from Energy primarily due to higher realized power prices for Western Power and incremental earnings from Halton Hills and Coolidge, partially offset by lower contributions from Bruce B, Natural Gas Storage and U.S. Power;

increased Comparable Interest Expense primarily due to decreased capitalized interest upon placing Keystone and other new assets in service, and higher interest expense as a result of U.S. dollar-denominated debt issuances in June and September 2010, partially offset by gains on derivatives used to manage the Company's exposure to rising interest rates in 2011 compared to losses incurred in 2010 and the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest expense;

decreased Comparable Interest Income and Other primarily due to lower realized gains in 2011 compared to 2010 on derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income;

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

increased Non-Controlling Interests due to the sale of a 25 per cent interest in GTN LLC and Bison LLC to TC PipeLines, LP in May 2011 and the reduction in the Company's ownership interest in TC PipeLines, LP; and

increased Preferred Share Dividends recorded on preferred shares issued in 2010.

Comparable Earnings increased \$36 million and decreased \$0.06 per share in 2010 compared to 2009. The increase in Comparable Earnings was primarily due to increased capitalized interest relating to Keystone and other capital projects. This increase was partially offset by decreased EBIT from Natural Gas Pipelines and Energy as discussed later. The decrease in Comparable Earnings on a per share basis reflected the issuance of 58.4 million common shares in second quarter 2009 and common shares issued in 2010 and 2009 under the Company's DRP.

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On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. operations is significantly offset by other U.S. dollar-denominated items as set out in the following table. The resultant pre-tax net exposure is managed using derivatives, further reducing the Company's exposure to changes in Canadian-U.S. foreign exchange rates. The

average exchange rate to convert a U.S. dollar to a Canadian dollar for the year ended December 31, 2011 was 0.99 (2010 1.03; 2009 1.14).

Summary of Significant U.S. Dollar-Denominated Amounts

Year ended December 31 (millions of dollars)	2011	2010	2009
U.S. Natural Gas Pipelines Comparable EBIT ⁽¹⁾	786	710	682
U.S. Oil Pipelines Comparable EBIT ⁽¹⁾	301		
U.S. Power Comparable EBIT ⁽¹⁾	164	187	78
Interest on U.S. dollar-denominated long-term debt	(734)	(680)	(645)
Capitalized interest on U.S. capital expenditures	116	290	123
U.S. non-controlling interests and other	(192)	(164)	(132)
	441	343	106

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

FORWARD-LOOKING INFORMATION

This MD&A contains 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", "intend", "target", "plan" 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 plans and financial outlook. Forward-looking statements in this document may include, but are not limited to, statements regarding:

anticipated business prospects;

financial performance of TransCanada and its subsidiaries and affiliates;

expectations or projections about strategies and goals for growth and expansion;

expected cash flows;

expected costs;

expected costs for projects under construction;

expected schedules for planned projects (including anticipated construction and completion dates);

expected regulatory processes and outcomes;

expected outcomes with respect to legal proceedings, including arbitration;

expected capital expenditures;

expected operating and financial results; and

expected impact of future commitments and contingent liabilities.

These forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. By their nature, forward-looking statements are subject to various assumptions, risks and uncertainties which could cause TransCanada's actual results and achievements to differ materially from the anticipated results or expectations expressed or implied in such statements.

Key assumptions on which TransCanada's forward-looking statements are based include, but are not limited to, assumptions about:

inflation rates, commodity prices and capacity prices;

timing of debt issuances and hedging;

regulatory decisions and outcomes;

arbitration decisions and outcomes;

foreign exchange rates;

interest rates;

tax rates;

planned and unplanned outages and utilization of the Company's pipeline and energy assets;

asset reliability and integrity;

access to capital markets;

anticipated construction costs, schedules and completion dates; and

acquisitions and divestitures.

The risks and uncertainties that could cause actual results or events to differ materially from current expectations include, but are not limited to:

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;

amount of capacity payments and revenues from the Company's energy business;

regulatory decisions and outcomes;

outcomes with respect to legal proceedings, including arbitration;

counterparty performance;

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;

weather;

technological developments; and

economic conditions in North America.

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 against placing undue reliance on 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 publicly update or revise any forward-looking information in this MD&A or otherwise, 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, EBITDA, Comparable EBITDA, EBIT, Comparable EBIT, Comparable Interest Expense and Comparable Interest Income and Other, Comparable Income Taxes and Funds Generated from Operations in this MD&A. These measures do not have any standardized meaning as prescribed by CGAAP. 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, net income attributable to non-controlling interests and preferred share dividends. EBIT is a measure of the Company's earnings from ongoing operations and is generally used to better measure performance and evaluate trends within each segment. EBIT comprises earnings before deducting interest and other financial charges, income taxes, net income attributable to non-controlling interests and preferred share dividends.

Comparable Earnings, Comparable EBITDA, Comparable EBIT, Comparable Interest Expense, Comparable Interest Income and Other and Comparable Income Taxes comprise Net Income Applicable to Common Shares, EBITDA, EBIT, Interest Expense, Interest Income and Other and Income Taxes, respectively, and are adjusted for specific items that are significant but are not reflective of the Company's underlying operations in the period. Specific items are subjective, however, management uses its judgement and informed decision-making when identifying items to be excluded in calculating these non-GAAP measures, some of which may recur. Specific items may include but are not limited to certain fair value adjustments relating to risk management activities, income tax refunds and adjustments, gains or losses on sales of assets, legal and bankruptcy settlements, and write-downs of assets and investments.

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

The Reconciliation of Non-GAAP Measures table in this MD&A presents a reconciliation of these non-GAAP measures to Net Income Attributable to Common Shares. Comparable Earnings per Common 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 its core strengths in its pipelines and energy businesses in North America. In 2012 and beyond, TransCanada expects that 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 current \$12 billion capital expenditure program, which includes Keystone XL and the Bruce Power restarts, 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.

TransCanada expects a positive impact on its 2012 earnings from assets that were placed in service in 2011 such as the Guadalajara natural gas pipeline, the Coolidge power facility and two Cartier Wind farm projects, from Keystone's Wood River/Patoka and Cushing Extension sections that began recording earnings in 2011, and from assets that are

expected to be placed in service in 2012, such as Bruce Power Units 1 and 2. TransCanada expects that as these assets are placed in service, its consolidated earnings for the year will be somewhat offset by a corresponding reduction in capitalized interest.

Natural Gas Pipelines' EBIT in 2012 will be affected by decisions made by applicable regulatory authorities, and the timing thereof, including the Canadian Mainline 2012 Tolls Application and Restructuring Proposal (Restructuring Proposal), as well as the establishment and expiry of long-term contracts, other variances in throughput volume, and rate settlements on its U.S. pipelines. Absent an NEB decision in 2012 with respect to Canadian Mainline 2012 tolls, EBIT from the Canadian Mainline will reflect the last approved rate of return on common equity (ROE) of 8.08 per cent on deemed common equity of 40 per cent, and will exclude incentive earnings that have enhanced Canadian Mainline's earnings in recent years.

Oil Pipelines EBIT in 2012 is expected to be higher than in 2011, primarily due to the impact of a full year of earnings being recorded on the Wood River/Patoka and Cushing Extension sections of Keystone compared to eleven months in 2011.

Energy's EBIT in 2012 is expected to be positively affected by assets that were placed in service during 2011 and assets that are expected to be placed in service in 2012. Energy's EBIT in 2012 could also be affected by the uncertainty and ultimate resolution of the capacity pricing issues in New York and outcome of the Sundance A PPA arbitration. 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 fluctuations in commodity prices.

TransCanada's earnings from its Natural Gas Pipelines, Oil Pipelines and Energy businesses in the U.S. 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 will be partially offset by corresponding 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 2012 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.

NATURAL GAS PIPELINES

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

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 24,373 km (15,145 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 16,656 km (10,350 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

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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.

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GTN Owned 75 per cent by TransCanada and 25 per cent by TC PipeLines, LP, 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. TransCanada operates GTN and effectively owns 83.3 per cent of the system through the combination of its direct ownership interest and its 33.3 per cent interest in TC PipeLines, LP.

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.

BISON Owned 75 per cent by TransCanada and 25 per cent by TC PipeLines, LP, 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. TransCanada operates Bison and effectively owns 83.3 per cent of the system through the combination of its direct ownership interest and its 33.3 per cent interest in TC PipeLines, LP.

GUADALAJARA Guadalajara is a 310 km (193 miles) natural gas pipeline from Manzanillo to Guadalajara in Mexico.

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 TC 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 33.3 per cent of the system through its 33.3 per cent interest in TC PipeLines, LP.

TUSCARORA Owned 100 per cent by TC 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 33.3 per cent of the system through its 33.3 per cent interest in TC PipeLines, LP.

NORTHERN BORDER Owned 50 per cent by TC PipeLines, LP, Northern Border is a 2,265 km (1,407 miles) natural gas transmission system serving the U.S. Midwest. TransCanada operates Northern Border and effectively owns 16.7 per cent of the system through its 33.3 per cent interest in TC PipeLines, LP.

GREAT LAKES Owned 53.6 per cent by TransCanada and 46.4 per cent by TC 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 69.0 per cent of the system through the combination of its direct ownership interest and its 33.3 per cent interest in TC 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.

ALASKA PIPELINE PROJECT The Alaska Pipeline Project is a proposed natural gas pipeline and a proposed treatment plant. The pipeline would extend 2,737 km (1,700 miles) from the treatment plant at Prudhoe Bay, Alaska to Alberta. TransCanada also commenced initial discussions with Alaska North Slope producers regarding an alternative pipeline route, the LNG option, that would extend from Prudhoe Bay to LNG facilities, to be built by third parties, located in south-central Alaska. TransCanada has entered into an agreement with ExxonMobil to jointly advance these projects.

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.

NATURAL GAS PIPELINES HIGHLIGHTS

Comparable EBIT from Natural Gas Pipelines was \$2.0 billion in 2011, an increase of \$0.1 billion from \$1.9 billion in 2010.

The Company invested \$0.9 billion in Natural Gas Pipelines capital projects in 2011 primarily related to growth on the Alberta System and construction of the Guadalajara pipeline.

In January 2011, the Bison natural gas pipeline was placed in service.

In June 2011, the Company's US\$360 million, 307 km (191 miles) Guadalajara natural gas pipeline went into service. This pipeline has capacity to transport 500 million cubic feet per day (MMcf/d) of natural gas to a power plant and 320 MMcf/d to the Pemex-owned national pipeline system near Guadalajara.

The Alberta System growth continues through new connections of supply primarily in the Horn River and Montney shale basins in B.C. as well as the Deep Basin in Alberta. In 2011, the NEB approved the construction of natural gas pipeline projects for the Alberta System with a capital cost of approximately \$910 million, including the approval to construct the Horn River pipeline with an estimated capital cost of \$275 million and an in-service date of second quarter 2012. In addition, Pipeline projects with a total capital cost of approximately \$810 million are still awaiting NEB decisions. The Company executed new agreements to further extend the Horn River pipeline by approximately 100 km (62 miles) at an estimated cost of \$230 million. Subject to regulatory approval this extension is projected to commence service in 2014.

In September 2011, TransCanada filed, with the NEB, the Restructuring Proposal, a comprehensive application to change the business structure and the terms and conditions of service for the Canadian Mainline including a 7.0 per cent after-tax weighted average cost of capital (ATWACC) fair return, revised depreciation rates and other parameters to address tolls for 2012 and 2013. The application also includes components that affect the Alberta System and Foothills. The NEB decision for this filing is expected in late 2012 or early 2013.

In November 2011, TransCanada refiled an application with the NEB including supplemental information to construct \$130 million of new pipeline infrastructure on the Canadian Mainline to receive Marcellus shale basin natural gas from the U.S. at the Niagara Falls receipt point for further transportation to Eastern markets.

In May 2011, TransCanada closed the sale of a 25 per cent interest in each of GTN LLC and Bison LLC to TC PipeLines, LP for an aggregate purchase price of US\$605 million plus closing adjustments, which included US\$81 million or 25 per cent of GTN LLC debt outstanding.

NATURAL GAS PIPELINES RESULTS

Year ended December 31 (<i>millions of dollars</i>)	2011	2010	2009
Canadian Natural Gas Pipelines			
Canadian Mainline	1,058	1,054	1,133
Alberta System	742	742	728
Foothills	127	135	132
Other (TQM, Ventures LP)	50	50	59
Canadian Natural Gas Pipelines Comparable EBITDA⁽¹⁾	1,977	1,981	2,052
Depreciation and amortization	(722)	(715)	(714)
Canadian Natural Gas Pipelines Comparable EBIT⁽¹⁾	1,255	1,266	1,338
U.S. Natural Gas Pipelines (in U.S. dollars)			
ANR	312	314	300
GTN ⁽²⁾	131	171	170
Great Lakes ⁽³⁾	101	109	120
TC PipeLines, LP ⁽²⁾⁽⁴⁾⁽⁵⁾	101	99	90
Iroquois	67	67	68
Bison ⁽⁵⁾	49		
Portland ⁽⁶⁾	22	22	22
International (Tamazunchale, Guadalajara, TransGas, Gas Pacifico/INNERGY) ⁽⁷⁾	77	42	52
General, administrative and support costs ⁽⁸⁾	(9)	(31)	(17)
Non-controlling interests ⁽⁹⁾	202	173	153
U.S. Natural Gas Pipelines Comparable EBITDA⁽¹⁾	1,053	966	958
Depreciation and amortization	(267)	(256)	(276)
U.S. Natural Gas Pipelines Comparable EBIT⁽¹⁾	786	710	682
Foreign exchange	(8)	24	105
U.S. Natural Gas Pipelines Comparable EBIT⁽¹⁾ (in Canadian dollars)	778	734	787
Natural Gas Pipelines Business Development Comparable EBITDA and EBIT⁽¹⁾	(52)	(62)	(62)
Natural Gas Pipelines Comparable EBIT⁽¹⁾	1,981	1,938	2,063
Summary:			
Natural Gas Pipelines Comparable EBITDA⁽¹⁾	2,967	2,915	3,093
Depreciation and amortization	(986)	(977)	(1,030)
Natural Gas Pipelines Comparable EBIT⁽¹⁾	1,981	1,938	2,063
Specific items:			
Valuation provision for MGP ⁽¹⁰⁾		(146)	
Dilution gain from reduced interest in TC PipeLines, LP ⁽¹¹⁾			29
Natural Gas Pipelines EBIT⁽¹⁾	1,981	1,792	2,092

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

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- (2) Results reflect TransCanada's direct ownership of 75 per cent of GTN effective May 2011 when 25 per cent was sold to TC PipeLines, LP, and 100 per cent prior to that date. GTN's results also include North Baja until July 2009, when North Baja was sold to TC PipeLines, LP.
- (3) Represents TransCanada's 53.6 per cent direct ownership interest.
- (4) Effective May 2011, TransCanada's ownership interest in TC PipeLines, LP decreased from 38.2 per cent to 33.3 per cent. Results reflect TransCanada's indirect effective ownership interest of 8.3 per cent in each of GTN and Bison effective May 2011. Effective November 18, 2009, TC PipeLines, LP's results reflected TransCanada's effective ownership in TC PipeLines, LP of 38.2 per cent. From July 1, 2009 to November 17, 2009, TransCanada's ownership interest in TC PipeLines, LP was 42.6 per cent. From January 1, 2009 to June 30, 2009, TransCanada's ownership interest in TC PipeLines, LP was 32.1 per cent.
- (5) Results reflect TransCanada's direct ownership of 75 per cent of Bison effective May 2011 when 25 per cent was sold to TC PipeLines, LP and 100 per cent since January 2011 when Bison went into service.
- (6) Portland's results reflect TransCanada's 61.7 per cent ownership interest.
- (7) Includes Guadalajara effective June 2011.
- (8) Represents General, Administrative and Support Costs associated with certain of the Company's pipelines, including \$17 million for the start up of Keystone in 2010.
- (9) Non-controlling interests reflects Comparable EBITDA for the 66.7 per cent and 38.3 per cent portions of TC PipeLines, LP and Portland, respectively, not owned by TransCanada.
- (10) In 2010, the Company recorded a valuation provision of \$146 million for its advances to the APG for the MGP.
- (11) As a result of TC PipeLines, LP issuing common units to the public in July 2009, the Company's ownership interest in TC PipeLines, LP was reduced to 38.2 per cent from 42.6 per cent and a dilution gain of \$29 million was realized.

Natural Gas Pipelines' Comparable EBIT was \$1,981 million in 2011 compared to \$1,938 million in 2010. 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 was \$2,063 million excluding the \$29 million dilution gain resulting from TransCanada's reduced interest in TC PipeLines, LP, which occurred as a result of the public issuance of common units by TC PipeLines, LP in November 2009.

Wholly Owned Canadian Natural Gas Pipelines Net Income

Year ended December 31 (<i>millions of dollars</i>)	2011	2010	2009
Canadian Mainline	246	267	273
Alberta System	200	198	168
Foothills	22	27	23

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 ROE, the level of deemed common equity, potential incentive earnings and changes in the level of depreciation, financial charges and income taxes which are recovered in revenue on a flow-through basis.

The Canadian Mainline operated under a five-year tolls settlement from 2007 through 2011. The cost of capital reflected 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 operating, maintenance and administration (OM&A) costs for each of the five years. All other cost elements of the revenue requirement were treated on a flow-through basis. The settlement also allowed for performance-based incentive arrangements that the Company believes were mutually beneficial to TransCanada and its customers.

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The Canadian Mainline's net income of \$246 million in 2011 was \$21 million lower compared to 2010 as a result of a lower ROE of 8.08 per cent in 2011 compared to 8.52 per cent in 2010 and a lower average investment base, partially offset by higher incentive earnings. Net income in 2010 was \$6 million lower compared to 2009. This decrease was primarily due to lower OM&A incentive earnings 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.

The Canadian Mainline's Comparable EBITDA was \$1,058 million in 2011 compared to \$1,054 million and \$1,133 million in 2010 and 2009, respectively. EBITDA variances reflect the net income variances discussed above as well as variances in depreciation, financial charges and income taxes recovered in revenue on a flow-through basis.

Capital Expenditures for the Canadian Mainline were \$65 million in 2011 compared with \$50 million and \$61 million in 2010 and 2009, respectively.

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 the 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 which are 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. 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. All other cost elements of the revenue requirement are treated on a flow-through basis. In 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 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-through basis.

The Alberta System's net income of \$200 million in 2011 was \$2 million higher compared to 2010. The increase is primarily due to higher earnings as a result of a growing average investment base. Net income in 2010 was \$30 million higher than in 2009. This increase reflected an ROE of 9.70 per cent on 40 per cent deemed common equity in 2010 compared to the earnings achieved under the settlement in place in 2009 and a higher average investment base, partially offset by lower incentive earnings. The increase in average investment base from 2009 to 2011 reflects capital expenditures to expand capacity in response to growing customer demand for service.

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The Alberta System's Comparable EBITDA of \$742 million in 2011 was consistent with 2010. Comparable EBITDA in 2010 was \$14 million higher than 2009. EBITDA variances from the Alberta System reflect the net income variances discussed above as well as variances in depreciation, financial charges and income taxes recovered in revenue on a flow-through basis.

Foothills The Foothills System's net income of \$22 million in 2011 was \$5 million lower compared to 2010. The decrease was primarily due to lower earnings from a lower average investment base and lower OM&A incentive earnings. Net income in 2010 was \$4 million higher than 2009, 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 were based on the NEB ROE formula of 8.57 per cent on deemed common equity of 36 per cent.

The Foothills System's Comparable EBITDA of \$127 million in 2011 was \$8 million lower compared to 2010. Comparable EBITDA in 2010 was \$3 million higher than 2009. EBITDA variances from the Foothills System reflect the net income variances discussed above as well as variances in depreciation, financial charges and income taxes recovered in revenue on a flow-through basis.

Other Canadian Natural Gas Pipelines Comparable EBITDA from Other Canadian Natural Gas Pipelines of \$50 million in 2011 was consistent with 2010 and was \$9 million lower than 2009 primarily due to an adjustment in 2009 as a result of the NEB's decision with respect to TQM cost of capital for 2007 and 2008.

ANR ANR's natural gas transportation and storage services are provided for under tariffs regulated by the FERC. These tariffs include maximum and minimum rates for services and allow 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 that was effective beginning in 1997. ANR Pipeline Company is not required to conduct a review of currently effective rates with the FERC at any time in the future but is not prohibited from filing for new rates if necessary. ANR Storage Company, which is a FERC regulated entity that owns and operates certain storage fields in Michigan, has rates that were established pursuant to a settlement approved by the FERC that were effective beginning in 1990. ANR Storage Company is currently subject to a review, initiated by the FERC in late 2011, of its existing rates.

ANR's EBITDA is affected by the contracting and pricing of its existing transportation and storage capacity, expansion projects, delivered volumes and incidental commodity 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 2011 was US\$312 million, a decrease of US\$2 million compared to 2010. The decrease was primarily due to higher OM&A costs partially offset by higher transportation revenues, a settlement with a counterparty and incidental commodity sales. Comparable EBITDA in 2010 of US\$314 million increased US\$14 million compared to 2009, primarily due to lower OM&A costs, partially offset by lower contracted firm long-haul transportation sales and storage revenues.

GTN GTN is regulated by the FERC and is operated in accordance with tariffs that establish maximum and minimum rates for various services. GTN is permitted to discount or negotiate rates on a non-discriminatory basis. In 2011, GTN

negotiated a settlement for new rates with its customers in lieu of filing a rate case. The FERC approved the settlement agreement in November 2011 for new rates effective January 1, 2012. The settlement includes a four-year moratorium during which GTN and the settling parties are prohibited from taking certain actions, including making any filings to adjust rates prior to December 31, 2015. The settlement also requires GTN to file for new rates that are to be effective January 1, 2016.

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 from TransCanada's direct investment was US\$131 million in 2011, a decrease of US\$40 million compared to 2010. The decrease was primarily due to TransCanada's May 2011 sale of a 25 per cent interest in GTN to TC PipeLines, LP and decreased revenue. Comparable EBITDA in 2010 increased US\$1 million compared to 2009, primarily due to lower OM&A costs and incremental proceeds accrued in 2010 relating to bankruptcy distributions from Calpine, partially offset by the impact of selling North Baja to TC PipeLines, LP in July 2009 and the write-off of costs in 2010 related to an unsuccessful information systems project.

Other U.S. Natural Gas Pipelines Comparable EBITDA from the remainder of the U.S. Natural Gas Pipelines was US\$610 million in 2011 compared to \$481 million in 2010. The increase was primarily due to the start of commercial operations of Bison and Guadalajara pipelines in January 2011 and June 2011, respectively, as well as the 25 per cent sale of TransCanada's ownership interest in GTN to TC PipeLines, LP in May 2011. Other contributing factors were lower general, administrative and support costs in 2011, partially offset by lower Great Lakes revenues in 2011. Comparable EBITDA in 2010 decreased US\$7 million from 2009, primarily due to lower Great Lakes revenues.

Business Development Natural Gas Pipelines' Business Development Comparable EBITDA loss from business development expenses was \$52 million in 2011 compared to \$62 million in 2010. This improvement of \$10 million was primarily due to lower business development costs associated with the Alaska Pipeline Project as a result of increased reimbursement by the State of Alaska to 90 per cent from 50 per cent effective July 31, 2010. Comparable EBITDA loss of \$62 million in 2010 was consistent with 2009.

Depreciation and Amortization Depreciation and Amortization for Natural Gas Pipelines was \$986 million in 2011, an increase of \$9 million from 2010. The increase was primarily due to the start-up of Bison and Guadalajara partially offset by lower depreciation for Great Lakes as a result of the lower depreciation rate in Great Lakes' 2010 rate settlement. Depreciation and Amortization decreased \$53 million in 2010 from 2009 primarily due to a weaker U.S. dollar in 2010 and lower depreciation for Great Lakes as a result of its 2010 rate settlement.

NATURAL GAS PIPELINES OPPORTUNITIES AND DEVELOPMENTS

Introduction Opportunities for North American natural gas pipeline infrastructure are impacted by the developments in the natural gas exploration and production sector. Rapidly increasing supply of hydrocarbons from shale and other tight or low permeability resource plays, particularly in the past five years, are transforming the domestic natural gas market. These resource plays are being further developed due to the recent wide-spread application of horizontal drilling together with multi-stage hydraulic fracturing (fracking) that is reshaping the natural gas industry. For example, North America has evolved from having numerous projects and proposals in various stages of development for liquefied natural gas (LNG) import facilities as recently as five years ago to the current situation where both the Canadian and U.S. regulators have issued and are considering additional LNG export licenses due to the significant increase in North American natural gas supply.

The abundance of supply resulting in relatively low natural gas prices across North America is supportive of increased reliance on natural gas to meet growing energy demands. A shift to increased natural gas fired power generation is also emerging in the U.S. and Canada. Numerous proposals for development of LNG export facilities from North America is another example of the evolution of the natural gas industry. Persistently high oil prices, particularly relative

to North America natural gas prices, have resulted in increased deployment of capital for the exploration and production of liquid-rich hydrocarbon basins, which also tend to produce associated natural gas. A recent announcement by the Mexican government to change its procurement strategy away from LNG imports to infrastructure improvements that facilitate increased access to natural gas supply from the U.S. is further evidence of the increased confidence in the availability of supply at stable prices across North America.

The evolution of the natural gas market is also driving changes to traditional flow patterns across the continental pipeline grid resulting in reassessment of the use and repurposing of existing assets. TransCanada's portfolio of North American natural gas pipeline infrastructure is well positioned to capture investment opportunities from growing natural gas supply as well as opportunities to connect new markets while satisfying increasing demand for natural gas within existing markets.

The following are significant initiatives by TransCanada to capture opportunities in the evolving natural gas industry in North America:

Canadian Mainline In September 2011, TransCanada filed the Restructuring Proposal, a comprehensive application with the NEB to change the business structure and the terms and conditions of service for the Canadian Mainline. The application included the following components:

Extension of the Alberta System footprint to points on the Canadian Mainline in Saskatchewan, and on the Foothills System in Saskatchewan and B.C., thereby reducing the cost to transport gas from the Western Canada Sedimentary Basin (WCSB) to markets served by the Canadian Mainline.

Lower depreciation expense and therefore lower tolls resulting from adjustments to the economic planning horizons for the three Canadian Mainline segments and a reallocation of accumulated depreciation to better match consumed service value for each segment.

Changes to toll design, services, and pricing resulting in higher revenues and lower overall tolls.

A 7.0 per cent ATWACC fair return which is equivalent to an ROE of 12 per cent on deemed common equity of 40 per cent.

In October 2011, TransCanada filed supplementary information on cost of service and the proposed tolls for 2012 and 2013. These applied-for tolls result in a 2012 toll of \$1.29 per gigajoule for transportation from Nova Inventory Transfer to the Dawn, Ontario delivery point, which is 38 per cent lower than the comparable toll charged in 2011.

The Restructuring Proposal was developed by TransCanada as an innovative and balanced response to recent and dramatic changes in the business environment of natural gas supply, demand and transportation in North America. The application is intended to enhance the long-term economic viability and sustainability of the Canadian Mainline and the WCSB. A decision regarding the Restructuring Proposal is expected in late 2012 or early 2013.

TransCanada re-filed an application with the NEB in November 2011 that included supplemental information for approval to construct \$130 million of new pipeline infrastructure on the Canadian Mainline, to receive Marcellus shale basin gas at the Niagara Falls receipt point for further transportation to Eastern markets. Subject to regulatory approval to construct the facilities, deliveries from Niagara Falls are expected to begin at a rate of 230 MMcf/d in November 2012 and then increase to 350 MMcf/d by November 2013, which may require a subsequent application for additional facilities.

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

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

TransCanada continues to advance pipeline development projects in B.C. and Alberta to transport new natural gas supply. The Company has filed applications with the NEB requesting approval for expansions of the Alberta System to accommodate requests for additional natural gas transmission service throughout the northwest and northeast portions of the WCSB. TransCanada has incremental firm commitments to transport approximately 3.4 billion cubic feet per day (Bcf/d) from western Alberta and northeast B.C. by 2014. Further requests for additional volumes on the Alberta System from the northwest portion of the WCSB have been received. In 2011, including the projects discussed above, the NEB has approved natural gas pipeline projects with capital costs of approximately \$910 million. Further pipeline projects with a total capital cost of approximately \$810 million are awaiting NEB decision. In addition, infrastructure to connect WCSB supply to markets continues to be pursued particularly to support further development of Alberta oil sands production and to supply proposed LNG export facilities on the Pacific Coast.

The Alberta System filed an application in October 2011 with the NEB to implement a new business model to restructure the commercial terms applied to existing natural gas liquids entering the Alberta System. The Natural Gas Liquids Extraction Model (NEXT) implementation date is proposed to be effective November 1, 2013. NEXT is designed to address the inequities caused by the current extraction convention, and improve the competitiveness of the Alberta System and the WCSB.

Commercial integration of the Alberta System and ATCO Pipelines system commenced in October 2011. Under the Agreement, the combined facilities of the two systems are commercially operated as a single transmission system and transportation service is provided to customers by NOVA Gas Transmission Ltd. (NGTL) pursuant to NGTL's Tariff and suite of rates and services. This agreement further identifies distinct geographic areas within Alberta for the construction of new facilities by each of NGTL and ATCO Pipelines. The final stage in this integration project is the swapping of certain pipeline assets of equal value. An application to the NEB for approval of the asset swaps is anticipated in the first quarter 2012.

Canadian Mainline, Alberta System and Foothills 2012 Tolls TransCanada filed for and received approval to implement interim 2012 tolls on the Canadian Mainline effective January 1, 2012, at the same level as the currently approved 2011 final tolls. In addition, TransCanada filed for interim 2012 tolls on the Alberta System and annual tolls for Foothills to be effective January 1, 2012. These tolls have also been approved on an interim basis pending the outcome of the NEB's decision on the Restructuring Proposal.

U.S. Pipelines In May 2011, TransCanada closed the sale of a 25 per cent interest in each of GTN and Bison to TC PipeLines, LP for an aggregate purchase price of US\$605 million, which included US\$81 million or 25 per cent of GTN's debt plus customary closing adjustments.

GTN GTN executed a settlement agreement with its shippers for new transportation rates to be effective January 2012 through December 2015. The settlement agreement was filed in August 2011 and approved by the FERC in November 2011.

Northern Border Northern Border operates pursuant to maximum long-term mileage-based rates and seasonal short-term transportation rates approved by the FERC in a January 2007 rate case settlement. A moratorium on the filing of future rate cases under National Gas Act Sections 4 or 5 expired on January 1, 2010. Northern Border is required to file a rate case on or before December 31, 2012.

Tuscarora Tuscarora Gas Transmission filed a settlement agreement with the FERC in December 2011 that concluded a review of Tuscarora's currently effective rates. The agreement, subject to the FERC approval, will lower shippers' reservation and transportation charges, and preclude another rate case until 2014.

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ANR In September 2011, ANR Pipeline Company filed an application with the FERC to sell its offshore Gulf of Mexico assets and certain related onshore facilities to its wholly-owned subsidiary, TC Offshore LLC. At the same time, TC Offshore LLC requested authorization from the FERC to acquire, own and operate those facilities under the FERC's regulations. These filings are currently pending before the FERC and a decision is expected in second or third quarter 2012.

Alaska Pipeline Project The Alaska Pipeline Project team continues to work with shippers to resolve conditional bids received as part of the project's open season and is working toward the FERC application deadline of October 2012 for the Alberta option that would extend from Prudhoe Bay to points near Fairbanks and Delta Junction, and then to the Alaska-Canada border, where the pipeline would connect with a new pipeline in Canada. The pipeline in Canada would extend from the Alaska-Canada border to link up with pipeline systems near Boundary Lake, Alberta, providing the capability of transporting natural gas into the continental U.S. TransCanada has commenced initial discussions with Alaska North Slope producers regarding an alternative pipeline route, the LNG option, that would require a pipeline from Prudhoe Bay to LNG facilities, to be built by third parties, located in south-central Alaska. TransCanada has entered into an agreement with Exxon Mobil Corporation (ExxonMobil) to jointly advance the project.

The Mackenzie Gas Project The MGP received its Certificate of Public Convenience and Necessity in March 2011, marking the end of the Federal regulatory process. The proponents of the 1,196 km, 30 inch pipeline, with an initial capacity of 1.2 Bcf/d, continue to seek the Canadian government's support for an acceptable fiscal framework which would allow the project to progress.

Mexico The Guadalajara Pipeline in Mexico began commercial operations in June 2011. The US\$360 million, 310 km (193 miles) project has capacity to transport 500 MMcf/d of natural gas to a power plant and 320 MMcf/d to the Pemex-owned national pipeline system near Guadalajara. The pipeline is secured under 25-year contracts with the Comisión Federal de Electricidad (CFE), Mexico's federal government owned electrical power company. In 2011, natural gas shipments were limited to support testing and commissioning efforts at the power plant. TransCanada and the CFE have agreed to add a US\$60 million compressor station to the pipeline that is expected to be operational in early 2013.

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 certain 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, as well as in the WCSB. After declining over the past four years, WCSB production showed signs of recovery in 2011. 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 supply choices for customers. This change has contributed to a trend of continued reduction in long-haul, long-term firm contracted capacity and a shift to shorter-distance, short-term firm and interruptible contracts on many 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. 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. The Alberta System, however, faces competition for connection to supply, particularly in northeast B.C., where the largest new source of natural gas has access to two existing pipeline companies with infrastructure in the area.

The Canadian Mainline, with its primary source of supply being the WCSB, also seeks opportunities to increase market share in Canadian domestic markets. However, TransCanada expects to continue to face competition for both the eastern domestic markets and in particular, the northeastern U.S. export markets. Consumers in the northeastern U.S. generally have access to natural gas through numerous delivery 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 per unit 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 sale of pipeline transportation capacity in the U.S. Gulf Coast region is highly competitive given the extensive natural gas pipeline network in this region. ANR must also compete for supply from interconnects with pipelines originating within the growing U.S. midcontinent shale gas formations and the U.S. Rockies production regions. Lower natural gas prices could result in reduced drilling activity and slow the rate of supply growth that has been fuelling investments in pipeline infrastructure additions in the U.S. midcontinent which could limit the number of incremental pipeline investment opportunities in the future.

ANR competes for market share with other natural gas pipelines and storage operators in its primary markets in the U.S. Midwest. As transportation capacity has become more abundant due to major pipeline additions over the past few years, lower natural gas prices that result in less available supply could negatively affect the value of pipeline capacity. The value of ANR's natural gas 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 out of the U.S. Rockies basin to the California border that went in service in July 2011.

Great Lakes and Northern Border are subject to annual contract renewals and can experience demand changes related to seasonal market conditions. To the extent the capacity on these pipelines is contracted, utilization does not impact revenue significantly. Both pipelines compete for natural gas transportation customers with pipelines that transport gas exiting the WCSB. An increase in competition in the key markets served by TransCanada's pipeline systems could arise from new ventures or expanded operations from existing competitors. For Great Lakes, the combination of growing supply from the Rockies, Mid-Continent and Marcellus shale developments reaching Dawn, Ontario through both new and available pipeline capacity, as well as reduced demand due to the economic environment, has the potential to maintain competitive pressures on WCSB supply into the Midwest. For example, if the transport of natural gas from those other supply basins to Dawn becomes more economical on competitive pipeline routes, then those supplies could reach the eastern zone of Great Lakes' market area and displace Great Lakes' long-haul volumes.

Demand for Pipeline Capacity Demand for pipeline capacity is created by supply and market competition, variations in economic activity, weather variability, natural gas pipeline and storage competition and pricing of alternative fuels. Demand and supply in new locations often creates opportunities for new infrastructure, but it may also change flow patterns and potentially impact utilization of existing assets. For example, the proposed LNG export facilities on the west coast of B.C. have the potential to reduce demand for capacity on pipelines that transport WCSB supply to other markets. TransCanada's pipelines may be challenged to sell available transportation capacity as transportation contracts expire on its existing pipeline assets, as they have, for example, on the Great Lakes system in fourth quarter 2011. TransCanada expects its U.S. natural gas pipelines to become more exposed to the potential for revenue variability due to rapidly evolving supply dynamics, competition and trends toward shorter term contracting by shippers.

Demand for a pipeline's capacity is ultimately the key driver that enables the transportation services to be sold. There are four key factors that influence demand for pipeline capacity. They are the price of gas that influences the amount of supply, basin on basin competition that influences where the supply will be developed, technology that influences the cost and pace of development of the resource play, and price basis differentials that drive what markets the supply will flow to. The risks associated with each of these four factors are considered below.

Gas Price

The price of natural gas is a key driver for development and exploration of the resource. The current low gas prices in North America may slow drilling activities that in turn diminishes production levels, particularly in dry gas fields where the extra revenue generated from the entrained liquids is not available.

Basin on Basin Competition

Large producers often diversify their portfolios by developing several basins, but this is influenced by actual costs to develop the resource as well as economic access to markets and cost of the necessary pipeline infrastructure. Therefore, basin on basin competition impacts the extent and timing of a resource play development that in turn drives changing dynamics for demand of pipeline capacity.

Technology

The increased supply of natural gas in North America is primarily due to the application of technology to shale and tight gas plays that include both horizontal drilling and fracking. There is growing regulatory and public scrutiny over the impacts of fracking. Changes to the practices of fracking through changes in regulations could impact the costs and pace of development of natural gas plays.

Basis Differentials

In the period 2008 to 2011, there was more capacity added to the continental pipeline network than in any prior period in the history of the industry. Gas supply basins that were once constrained such as the U.S. Rockies and East Texas now have an overabundance of export capacity. As well, the recent focus on the development of shale gas basins has led to declines in conventional supply basins and unutilized capacity on many pipelines. These factors have led to contraction of regional basis differentials, the differences in market prices paid for natural gas between different gas receipt and delivery points, which has led to changes in the way many pipeline systems are being used. As a result, many pipeline companies are moving to restructure their business models, rate designs and services to adapt to the changing flow dynamics.

Regulatory Risk Regulatory decisions continue to have an impact on the financial returns from existing investments in TransCanada's natural gas pipelines and are expected to have a similar impact on financial returns from future investments. TransCanada manages this risk through rate applications and negotiated settlements, where possible.

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

Pipeline Abandonment Cost Risk Through the Land Matters Consultation Initiative (LMCI), the NEB is addressing several significant issues relating to future pipeline abandonment costs for Canadian regulated pipelines. During the LMCI process, the NEB provided several key guiding principles including the position that abandonment costs are a legitimate cost of providing pipeline service and are recoverable, upon NEB approval, from users of the system. Based on the NEB's direction, the earliest that collection of funds for future pipeline abandonment costs through cost-of-service tolls on Canadian regulated pipelines could begin would be 2015.

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

NATURAL GAS PIPELINES OUTLOOK

The WCSB remains an important supply basin for TransCanada's pipeline infrastructure, however, the Company's portfolio of pipelines across North America has broadened its supply source to include many other prolific and emerging supply areas.

TransCanada expects there will be excess natural gas pipeline capacity from the WCSB to markets outside Western Canada for the foreseeable future as a result of capacity expansions on natural gas pipelines over the past 15 years, competition from other pipelines and supply basins, and significant growth in natural gas consumption within Alberta driven primarily by oil sands development and electricity generation requirements.

The WCSB has an ultimate remaining conventional resource estimate of 126 trillion cubic feet. In addition, the ultimate potential of the basin has been vastly improved due to the advent of economic access to shale gas and tight gas. Over its history, the WCSB's ultimate potential has primarily reflected the economic productivity of the conventional resource base. The recent additions of unconventional resources together with the increasing economic viability of low quality conventional resources as a result of new drilling and completion technology, has in TransCanada's view, more than doubled the technically accessible resource base of the WCSB.

WCSB production is expected to increase slightly in 2012. Despite reduced overall drilling levels across the WCSB, the dramatic increases in initial productivity resulting from horizontally drilled wells, in combination with a renewed focus on associated natural gas liquids, has significantly offset the anticipated negative supply impact associated with reduced levels of conventionally drilled vertical wells. Drilling activity has increased in northwestern Alberta and northeastern B.C. as producers develop projects to access deeper multi-zone gas plays, shales and tight sands utilizing horizontally-drilled wells in combination with fracking 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 supply regions is currently approximately 1.5 Bcf/d.

The outlook for demand driven infrastructure for WCSB supply within Western Canada remains positive with continued growth expected in Alberta oil sands development and coal conversion to natural gas for power generation. In addition, in the second half of this decade, there is also potential for additional new markets in the Asia-Pacific region for WCSB gas, connecting to new LNG terminals which are proposed along the west coast of B.C. to export Canadian gas.

Demand for WCSB-sourced natural gas in Eastern Canada and the U.S. Northeast decreased in 2011, 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.

In the U.S., TransCanada expects that unconventional production will continue to grow from established shale gas plays in eastern Texas, northwestern Louisiana, Arkansas, southwestern Oklahoma and the Appalachian region. The Marcellus shale basin continues to grow and with new pipeline infrastructure coming on-stream, is changing the dynamics for gas flows into and out of the U.S. Northeast. In addition, development of the Utica shale basin (predominantly in Ohio) is in its infancy. This basin has significant potential to become another major natural gas supply source. Production focus has shifted in the near term toward more oil and liquids-rich hydrocarbon production, which is expected to increase associated natural gas supply in Texas, North Dakota and other areas. Supply from coalbed methane and tight gas sands in the U.S. Rockies is also expected to grow. The resulting anticipated growth in U.S. supply should provide additional opportunities for TransCanada's U.S. pipelines. U.S. demand growth is expected to be driven primarily by increased use of natural gas for power generation and industrial growth, as well as LNG exports in the second half of the decade.

TransCanada continues to seek opportunities in Mexico to further develop natural gas infrastructure opportunities. TransCanada will leverage the experience and expertise gained on its Guadalajara and Tamazunchale pipelines and

intends to participate in the \$10 billion program recently announced by the Mexican government to expand its natural gas transmission infrastructure.

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.

Earnings Canadian Natural Gas Pipelines' earnings are affected by changes in investment base, ROE, capital structure and terms of toll settlements or other toll proposals as approved by the NEB, with the most significant variables being ROE, capital structure and investment base. Absent an NEB decision in 2012 with respect to Canadian Mainline 2012 tolls, earnings from the Canadian Mainline will be lower than in 2011 as results will reflect the last approved ROE of 8.08 per cent on deemed common equity of 40 per cent, and will exclude incentive earnings that have enhanced Canadian Mainline's earnings in recent years. The Company expects continued growth of the Alberta System investment base as new supply in northeastern B.C. and western Alberta 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, the result of which 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 ability to recontract unsold capacity on TransCanada's U.S. pipelines and to sell 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 these markets. 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 \$0.9 billion in 2011. Capital spending for the Company's wholly owned pipelines is expected to be approximately \$1.0 billion in 2012.

NATURAL GAS THROUGHPUT VOLUMES

<i>(Bcf)</i>	2011	2010	2009
Canadian Mainline ⁽¹⁾	1,887	1,666	2,030
Alberta System ⁽²⁾	3,517	3,447	3,538
ANR	1,706	1,589	1,575
Foothills	1,289	1,446	1,205
Northern Border	971	902	706
Great Lakes	830	804	727
GTN	679	802	797
Iroquois	317	343	355
TQM	154	151	164
Ventures LP	150	144	145
Bison ⁽³⁾	105		
North Baja	92	60	96
Tamazunchale	57	52	54
Gas Pacifico	46	51	62
Portland	36	36	37
Tuscarora	33	35	34
TransGas	26	30	28

(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 2011 were 1,160 Bcf (2010 1,228 Bcf; 2009 1,579 Bcf).

(2) Field receipt volumes for the Alberta System in 2011 were 3,622 Bcf (2010 3,471 Bcf; 2009 3,578 Bcf) and includes three months of ATCO Pipelines receipts consistent with the commercial integration of NGTL and ATCO Pipelines effective October 1, 2011.

(3) Effective January 14, 2011.

OIL PIPELINES

KEYSTONE

Keystone is a 3,467 km (2,154 miles) wholly owned and operated 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 Company plans to expand and extend the oil pipeline system to the U.S. Gulf Coast (Keystone XL) which includes the construction of a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast, the addition of operational storage facilities at Hardisty, Alberta and the construction of a new crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska. The expanded oil pipeline system is collectively referred to as Keystone. The completion of Keystone XL is expected to increase total system capacity to approximately 1.4 million bbl/d.

OIL PIPELINES HIGHLIGHTS

Wood River/Patoka and Cushing Extension sections of Keystone achieved full commercial operations in February 2011. The Company recorded EBITDA of \$587 million in its first eleven months of operations.

In August 2011, a favourable FEIS was received from the DOS for Keystone XL.

The Company secured commercial support for an extension and expansion of Keystone XL to provide crude oil transportation service from Hardisty, Alberta to Houston, Texas, increasing total long-term firm contracts on Keystone to in excess of 1.1 million bbl/d for an average term of approximately 18 years.

In January 2012, the DOS denied TransCanada's application requesting a Presidential Permit to construct Keystone XL based on the DOS's position that they did not have sufficient time to receive and review additional information necessary to assess alternative routes that would avoid the Sandhills region of Nebraska. The Company will reapply for a Presidential Permit for Keystone XL.

OIL PIPELINES RESULTS

Year ended December 31 ⁽¹⁾ (millions of dollars)	2011
Canadian Oil Pipelines Comparable EBITDA⁽²⁾	210
Depreciation and amortization	(49)
Canadian Oil Pipelines Comparable EBIT⁽²⁾	161
U.S. Oil Pipelines Comparable EBITDA⁽²⁾ (in U.S. dollars)	383
Depreciation and amortization	(82)
U.S. Oil Pipelines Comparable EBIT⁽²⁾	301
Foreign exchange	(3)
U.S. Oil Pipelines Comparable EBIT⁽²⁾ (in Canadian dollars)	298
Oil Pipelines Business Development Comparable EBITDA and EBIT⁽²⁾	(2)
Oil Pipelines Comparable EBIT⁽²⁾	457
Summary:	
Oil Pipelines Comparable EBITDA⁽²⁾	587
Depreciation and amortization	(130)
Oil Pipelines Comparable EBIT⁽²⁾	457

(1) Results reflect eleven months of operations.

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

OIL PIPELINES FINANCIAL ANALYSIS

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Keystone is a 3,467 km (2,154 miles) wholly owned and operated 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 Company plans to expand and extend the existing system through Keystone XL which includes the construction of a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast, the addition of operational storage facilities at Hardisty, Alberta and the construction of a new crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska. The expanded oil pipeline system is collectively referred to as Keystone. The completion of Keystone XL is expected to increase total system capacity to approximately 1.4 million bbl/d.

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The Marketlink projects would transport crude oil sourced from U.S. basins to refining markets in the Cushing, Oklahoma region and the U.S. Gulf Coast on facilities that form part of Keystone XL. The proposed Bakken Marketlink project would transport U.S. crude oil from Baker, Montana to Cushing and the proposed Cushing Marketlink project would transport crude oil from Cushing to Port Arthur and Houston, Texas.

Oil Pipelines Comparable EBIT for the year ended 2011 was \$457 million. EBITDA from Keystone is primarily generated from payments received under long-term commercial arrangements for committed capacity that are not dependent on actual throughput. Uncontracted capacity is offered to the market on a spot basis and, when capacity is available, provides opportunities to generate incremental EBITDA. In February 2011, the Company began recording EBITDA for the Wood River/Patoka and Cushing Extension sections.

Although the Wood River/Patoka section commenced commercial operations in June 2010, cash flows other than general, administrative and support costs were capitalized until February 2011. As a condition of the NEB's approval to begin operations, the Wood River/Patoka section operated 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 allowing the system to operate at its design pressure and throughput capacity.

Operating Statistics

Year ended December 31 ⁽¹⁾	2011
Delivery volumes (thousands of barrels) ⁽²⁾	
Total	137,384
Average	411

(1) Results reflect eleven months of operations.

(2) Delivery volumes reflect physical deliveries.

OIL PIPELINES OPPORTUNITIES AND DEVELOPMENTS

Wood River/Patoka and Cushing Extension In late January 2011, work was completed to allow the Wood River/Patoka section of the system to operate at its design pressure following the NEB's decision to remove the MOP restriction in December 2010. In February 2011, the Cushing Extension commenced commercial operations, extending the pipeline system to Cushing, Oklahoma and increasing nominal design capacity to 591,000 bbl/d.

In May 2011, revised fixed tolls came into effect for the Wood River/Patoka section of the system that reflected the final project costs for this section.

In June 2011, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a corrective action order on Keystone as a result of two above-ground incidents in second quarter 2011 at pump stations in North Dakota and Kansas, both of which involved the release of crude oil. Following the incidents, TransCanada took immediate action to contain the crude oil releases and repair the facilities. The corrective action order required TransCanada to develop and submit a written restart plan which included steps to facilitate the proper clean up, investigation, and system improvements and modifications. The restart plan was approved by PHMSA in June 2011. In July and August 2011, work was performed on the Keystone system to improve system reliability. The work was completed as planned and resulted in reduced pipeline capacity during those two months, however, it did not have a significant impact on EBIT.

In 2010, three entities, each of which had entered into Transportation Service Agreements for the Cushing Extension, had 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. All of the claims have been discontinued on a without-cost and without-liability basis.

Keystone XL The regulatory approval process for the U.S. portion of Keystone XL continued throughout 2011 and early 2012. Following an extensive environmental review process, the DOS, the lead agency for U.S. federal regulatory approvals, released its FEIS in August 2011. The FEIS found that the project would have no significant impact on the environment and that the proposed route would have the least environmental impact of the alternatives considered.

Following the issuance of the FEIS, the DOS initiated a 90-day National Interest Determination (NID) process. During the NID process, concern about the pipeline's impact on the Sandhills region of Nebraska was raised and on November 10, 2011, the DOS determined it necessary to identify and assess alternative routes that would avoid the Sandhills region in Nebraska in order to move forward with a decision on the Presidential Permit. The DOS indicated that the additional environmental review process including a public comment period on a supplement to the FEIS could be completed as early as first quarter 2013. In December 2011, the *Temporary Payroll Tax Cut Continuation Act* was approved by the U.S. Senate and the U.S. House of Representatives and signed into law by U.S. President Obama on December 23, 2011. The legislation required a final decision on the Keystone XL Presidential Permit by February 21, 2012.

On January 18, 2012, the DOS denied the Presidential Permit for Keystone XL, based on the DOS's position that it did not have sufficient time to receive and review additional information necessary to assess alternative routes that would avoid the Sandhills region of Nebraska. The DOS noted that its decision did not preclude TransCanada from submitting a subsequent Presidential Permit application for Keystone XL.

TransCanada is continuing to work with the State of Nebraska to determine the preferred route that avoids the Sandhills region in Nebraska. The Company will submit a revised Presidential Permit application to the DOS. Assuming regulatory approval is received by first quarter 2013, TransCanada believes it could have Keystone XL in service by early 2015. The Company continues to monitor political developments in the U.S. and the potential impact they may have on commencing construction of Keystone XL.

In December 2011, TransCanada announced that it had secured additional commercial support for Keystone XL following the successful conclusion of a binding open season offering long-term firm service for crude oil transportation from Hardisty, Alberta to Houston, Texas (Houston Lateral) increasing total long-term contracts on Keystone XL to in excess of 1.1 million bbl/d for an average term of approximately 18 years. The approximate US\$600 million Houston Lateral project would involve the expansion of capacity through additional pump units increasing the capacity of Keystone XL to 830,000 bbl/d and the construction of an approximately 80 km (50 miles) pipeline extension from the proposed Keystone XL system. The Houston Lateral is expected to more than double the U.S. Gulf Coast refining market capacity directly accessible from the Keystone pipeline system to over four million bbl/d and is expected to be in service by early 2015, subject to regulatory approvals.

The capital cost of Keystone XL, including the Houston Lateral, is estimated to be approximately US\$7.6 billion, with US\$2.4 billion having been invested at December 31, 2011. Of the amount invested to date, approximately 60 per cent of the total represents purchased equipment and materials. The remaining capital cost amount is expected to be invested between now and the in-service date of the expansion, which is expected by early 2015. Capital costs related to the construction of Keystone XL are subject to capital cost risk and reward sharing mechanisms with Keystone's long-term committed shippers.

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. In 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 Keystone XL. The capital cost of the incremental facilities is expected to be approximately US\$140 million and, pending regulatory approvals, commercial in service is anticipated in early 2015.

In fourth quarter 2011, TransCanada secured additional contractual support for the Cushing Marketlink project, which would transport crude oil from Cushing, Oklahoma to Port Arthur and Houston, Texas. The approximate US\$50 million Cushing Marketlink project would use a portion of the Keystone XL facilities including the Houston Lateral. Pending

regulatory approvals, Cushing Marketlink is expected to begin shipping crude oil to Port Arthur and Houston in early 2015.

OIL PIPELINES BUSINESS RISKS

Crude Oil Supply, Markets and Competition Alberta produces the majority of the crude oil in the WCSB and is the primary source of crude oil supply for Keystone. In 2011, the WCSB produced an estimated 2.7 million bbl/d, consisting of 1.1 million bbl/d of conventional crude oil and condensate, and 1.6 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 new shale oil production including the Bakken and Cardium formations and 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 2011, the Canadian Association of Petroleum Producers (CAPP) forecasted WCSB crude oil supply would increase to 3.5 million bbl/d by 2015 and to 4.5 million bbl/d by 2020, indicating future growth in Alberta crude oil production. CAPP estimated spending in the oil sands totalled \$19 billion in 2011 and is expected to increase from that level in 2012.

Keystone has contracted a significant portion of its capacity under long-term commercial arrangements. 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 2011, the Williston Basin achieved production rates of nearly 530,000 bbl/d. TransCanada expects production levels will reach approximately 840,000 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 more than 1.0 million bbl/d and has been growing 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 pipeline system are primarily refiners in the U.S. Midwest, midcontinent and Gulf Coast regions. TransCanada competes with pipelines that deliver WCSB, Williston Basin and Permian Basin crude oil to these refiners through interconnections with other pipelines. Keystone also competes with U.S. domestically-produced crude oil and imported crude oil for refining markets in the U.S. Midwest, Midcontinent and Gulf Coast regions.

Regulatory Risk Regulations and decisions issued by Canadian and U.S. regulatory bodies, including the NEB, FERC, EPA, Army Corps of Engineers, various state regulators, U.S. Department of Transportation, PHMSA and DOS, may have a significant impact on the approval, construction, operational 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.

Pipeline Abandonment Cost Risk Keystone's Canadian facilities are subject to the NEB's LMCI process previously discussed in the Natural Gas Pipelines Business Risks section in this MD&A. Future pipeline abandonment costs for Keystone's Canadian facilities are expected to be recovered in transportation tolls.

Throughput Risk TransCanada has secured long-term transportation contracts for most of Keystone's capacity. Payments received for this committed capacity are not dependent on actual throughput. Uncontracted capacity is offered to the market on a spot basis. Uncontracted throughput is dependent primarily on crude oil production levels, market competition for crude oil, refinery activity and variations in economic activity.

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. Unexpected plant outages will impact throughput capacity and may result in reduced contracted capacity payments and lower uncontracted transportation sales revenue.

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 on Keystone XL would be adjusted by a factor equal to 75 per cent of the percentage change in capital costs. 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 North American 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 2012 and 2013. Alberta oil sands production is forecast to increase to 2.3 million bbl/d by 2016 from 1.6 million bbl/d in 2011 and total Western Canada crude oil supply is projected to grow over the same period to 3.7 million bbl/d from 2.7 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 international markets and markets in the U.S., that are currently served by foreign imports. TransCanada will continue to pursue additional opportunities to transport crude oil from Alberta to new 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, and the U.S. Gulf Coast. TransCanada is competing with several other proposals to build pipeline capacity to transport crude oil supply from this region to U.S. refining centres. 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 pipeline capacity to transport oil supply 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. refining centres.

Earnings Oil Pipelines earnings in 2012 are expected to be higher than in 2011, primarily due to the impact of a full year of earnings being recorded for the Wood River/Patoka and Cushing Extension sections of Keystone compared to eleven months in 2011. Earnings are primarily generated by contractual arrangements for committed capacity that are not dependent on actual throughput. Uncontracted capacity offered to the market on a spot basis provides additional earnings opportunities. TransCanada expects earnings from its crude oil pipelines to increase as the proposed Keystone XL and Marketlink projects begin delivering crude oil. Once fully completed, TransCanada expects to record annual EBITDA of approximately US\$1.7 billion, based on contracted volumes in place and assuming a full year of commercial operations servicing both the U.S. Midwest and Gulf Coast markets.

Capital Expenditures Total capital spending for Oil Pipelines in 2011 was \$1.2 billion. Capital spending for Oil Pipelines in 2012 is expected to be approximately \$0.9 billion, primarily due to contractual commitments associated with Keystone XL and expansion of Keystone's Hardisty, Alberta facilities.

ENERGY

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.

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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 a 50 per cent interest in ASTC Power Partnership, which has a PPA that expires in 2020, in place for 100 per cent of the production from the 706 MW Sundance B power facility. 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 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.

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. Baie-des-Sables, Anse-à-Valleau, Carleton, Montagne-Sèche and phase one of Gros-Morne wind farms are in service and have a total generating capacity of 479 MW. Construction continues on the 111 MW second phase of the Gros-Morne wind farm which is expected to be operational in December 2012.

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.

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.

OCEAN STATE POWER 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 in Coolidge, Arizona, which was placed in service in second quarter 2011.

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 and, through an agreement made effective July 1, 2011, is now the operator of the facility.

ENERGY HIGHLIGHTS

Energy's Comparable EBIT was \$940 million in 2011, an increase of \$192 million from \$748 million in 2010.

In 2011, the Company invested \$1.1 billion in Energy capital projects which are all supported by long-term contracts, including:

the 575 MW Coolidge generating facility, which was placed in service in May 2011;

construction of the two remaining wind farms at Cartier Wind, including completion of the 58 MW Montagne-Sèche project and the 101 MW phase one of the Gros-Morne project; and

the restart of Bruce Power Units 1 and 2.

Refurbishment work on Bruce Power Units 1 and 2 reached significant milestones in 2011. Fuelling of both Units 1 and 2 has now been completed and the final phases of commissioning for Unit 2 are underway.

In December 2011, an agreement was executed for the purchase of nine Ontario solar projects with a combined capacity of 86 MW, for approximately \$470 million. TransCanada will purchase each project once construction and acceptance testing have been completed and operations have begun under 20-year PPAs with the OPA under the Feed-In Tariff program in Ontario. It is anticipated that the projects will be placed in service between late 2012 and mid-2013.

POWER PLANTS NOMINAL GENERATING CAPACITY AND FUEL TYPE

	MW	Fuel Type
Canadian Power		
Western Power		
Sheerness	756	Coal
Coolidge	575	Natural gas
Sundance A	560	Coal
Sundance B ⁽¹⁾	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 ⁽²⁾	365	Wind
Portlands Energy ⁽³⁾	275	Natural gas
Grandview	90	Natural gas
	1,963	
Bruce ⁽⁴⁾	2,480	Nuclear
	7,079	
U.S. Power		
Ravenswood	2,480	Natural gas/oil
TC Hydro	583	Hydro
Ocean State Power	560	Natural gas
Kibby Wind	132	Wind
	3,755	
Total Nominal Generating Capacity	10,834	

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

(2) Represents TransCanada's 62 per cent share of the total 590 MW project, including 111 MW under construction.

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

(4) Represents TransCanada's 48.8 per cent proportionate interest in Bruce A and 31.6 per cent proportionate interest in Bruce B, including 733 MW for Bruce A Units 1 and 2.

ENERGY RESULTS

Year ended December 31 <i>(millions of dollars)</i>	2011	2010	2009
Canadian Power			
Western Power ⁽¹⁾	489	220	279
Eastern Power ⁽²⁾	314	231	220
Bruce Power	252	298	352
General, administrative and support costs	(43)	(38)	(39)
Canadian Power Comparable EBITDA⁽³⁾	1,012	711	812
Depreciation and amortization	(276)	(242)	(227)
Canadian Power Comparable EBIT⁽³⁾	736	469	585
U.S. Power (in U.S. dollars)			
Northeast Power ⁽⁴⁾	314	335	210
General, administrative and support costs	(41)	(32)	(40)
U.S. Power Comparable EBITDA⁽³⁾	273	303	170
Depreciation and amortization	(109)	(116)	(92)
U.S. Power Comparable EBIT⁽³⁾	164	187	78
Foreign exchange	(4)	7	8
U.S. Power Comparable EBIT⁽³⁾ (in Canadian dollars)	160	194	86
Natural Gas Storage			
Alberta Storage	89	140	173
General, administrative and support costs	(6)	(8)	(9)
Natural Gas Storage Comparable EBITDA⁽³⁾	83	132	164
Depreciation and amortization	(14)	(15)	(14)
Natural Gas Storage Comparable EBIT⁽³⁾	69	117	150
Energy Business Development Comparable EBITDA and EBIT⁽³⁾	(25)	(32)	(37)
Energy Comparable EBIT⁽³⁾	940	748	784
Summary:			
Energy Comparable EBITDA⁽³⁾	1,338	1,125	1,131
Depreciation and amortization	(398)	(377)	(347)
Energy Comparable EBIT⁽³⁾	940	748	784

(1)

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Includes Coolidge effective May 2011.

(2) Includes Montagne-Sèche and phase one of Gros-Morne, Halton Hills, and Portlands Energy effective November 2011, September 2010 and April 2009, respectively.

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

(4) Includes phase one and two of Kibby Wind effective October 2009 and October 2010, respectively.

48 MANAGEMENT'S DISCUSSION AND ANALYSIS

ENERGY FINANCIAL ANALYSIS

Energy's Comparable EBIT was \$940 million in 2011 compared to \$748 million in 2010 and \$784 million in 2009.

Western Power As at December 31, 2011, 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 PPAs, five natural gas-fired cogeneration facilities and a simple-cycle, natural gas peaking facility 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 power plants with capacity ranging from 27 MW to 165 MW. 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. As described further in the Energy Opportunities and Developments section of this MD&A, no volumes were delivered under the Sundance A PPA in 2011. 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 in Alberta 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 in Alberta, as at December 31, 2011, Western Power had entered into fixed-price power sales contracts to sell approximately 8,400 gigawatt hours (GWh) in 2012 and 6,200 GWh in 2013.

Western U.S. power assets consist of the 575 MW Coolidge Generating Station which was placed in service in May 2011. Coolidge power output is fully contracted under a 20 year PPA with the Salt River Project, a local Arizona utility.

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, the in-service Cartier Wind farms, Portlands Energy and Grandview.

Halton Hills was placed in service in September 2010 and is fully contracted under a 20-year Clean Energy Supply contract with the OPA.

Bécancour's entire power output is supplied to Hydro-Québec under a 20-year power purchase contract expiring in 2026. Steam produced 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, while energy production and payments are suspended, TransCanada continues to receive capacity payments similar to those that would have been received under the normal course of operation.

The Montagne-Sèche and phase one of Gros-Morne Cartier Wind farms were placed in service November 2011, bringing the total generating capacity of the in-service Cartier Wind farms to 479 MW. 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 is fully contracted 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. Eastern Power sales volumes were 100 per cent sold under contract in 2011 and are expected to be fully contracted going forward.

Western and Eastern Canadian Power Comparable EBIT⁽¹⁾⁽²⁾⁽³⁾

Year ended December 31 (<i>millions of dollars</i>)	2011	2010	2009
Revenues			
Western power ⁽²⁾	1,081	714	788
Eastern power ⁽³⁾	475	330	281
Other ⁽⁴⁾	70	84	86
	1,626	1,128	1,155
Commodity purchases resold			
Western power	(538)	(431)	(451)
Other ⁽⁴⁾⁽⁵⁾	(9)	(26)	(26)
	(547)	(457)	(477)
Plant operating costs and other	(276)	(220)	(179)
General, administrative and support costs	(43)	(38)	(39)
Comparable EBITDA⁽¹⁾	760	413	460
Depreciation and amortization	(163)	(140)	(138)
Comparable EBIT⁽¹⁾	597	273	322

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

(2) Includes Coolidge effective May 2011.

(3) Includes Montagne-Sèche and phase one of Gros-Morne, Halton Hills, and Portlands Energy effective November 2011, September 2010 and April 2009, respectively.

(4) Includes sales of excess natural gas purchased for generation and sales of thermal carbon black. 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.

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

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Western and Eastern Canadian Power Operating Statistics

Year ended December 31	2011	2010	2009
Sales Volumes (GWh)			
Supply			
Generation			
Western Power ⁽¹⁾	2,606	2,373	2,334
Eastern Power ⁽²⁾	3,714	2,359	1,550
Purchased			
Sundance A & B and Sheerness PPAs ⁽³⁾	7,909	10,785	10,603
Other purchases	1,112	429	529
	15,341	15,946	15,016
Sales			
Contracted			
Western Power	9,245	10,211	9,944
Eastern Power	3,714	2,375	1,588
Spot			
Western Power	2,382	3,360	3,484
	15,341	15,946	15,016
Plant Availability⁽⁴⁾			
Western Power ⁽¹⁾⁽⁵⁾	97%	95%	93%
Eastern Power ⁽²⁾⁽⁶⁾	93%	94%	97%

(1) Includes Coolidge effective May 2011.

(2) Includes Montagne-Séche and phase one of Gros-Morne, Halton Hills and Portlands Energy effective November 2011, September 2010 and April 2009, respectively.

(3) No volumes were delivered under the Sundance A PPA in 2011.

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

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

(6) 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 \$489 million and Power Revenues of \$1,081 million in 2011 increased \$269 million and \$367 million, respectively, compared to 2010 primarily due to higher overall realized power prices in Alberta and incremental earnings from Coolidge, which went in service under a 20-year PPA in May 2011. Plant outages and higher demand resulted in average spot market power prices in Alberta increasing 51 per cent to \$77 per megawatt hour (MWh) in 2011 compared to \$51 per MWh in 2010. Approximately 20 per cent of Western Power's sales volumes were sold in the spot market in 2011 compared to 25 per cent in 2010.

Western Power's Comparable EBITDA in 2011 included \$156 million of accrued earnings from the Sundance A PPA, the revenues and costs of which have been recorded as though the outages of Sundance A Units 1 and 2 are interruptions of supply in accordance with the terms of the PPA. Refer to the Opportunities and Developments section in this MD&A for further discussion on the dispute regarding the Sundance A outage.

Eastern Power's Comparable EBITDA of \$314 million and Power Revenues of \$475 million in 2011 increased \$83 million and \$145 million, respectively, compared to 2010. These increases were primarily due to the full year impact of incremental earnings from Halton Hills, which was placed in service in September 2010.

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Western Power's commodity purchases resold of \$538 million increased \$107 million compared to 2010 due to increased direct sales to customers, higher PPA costs per MWh and higher volumes at Sheerness.

Plant Operating Costs and Other, which includes natural gas fuel consumed in power generation, of \$276 million in 2011 increased \$56 million from 2010 primarily due to incremental fuel consumed at Halton Hills.

Depreciation and amortization of \$163 million increased \$23 million in 2011 compared to 2010 primarily due to incremental depreciation from Halton Hills and Coolidge.

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. 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 in service September 2010 and April 2009, respectively, partially offset by lower contracted revenue from the Bécancour facility.

Plant Operating Costs and Other of \$220 million in 2010 increased \$41 million from 2009 primarily due to incremental fuel consumed at Portlands Energy and Halton Hills.

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 being refurbished. The two units being refurbished are expected to resume commercial operations in first and third quarter 2012. Bruce B has four operating reactors with a combined capacity of 3,200 MW. As at December 31, 2011, 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 (2010 and 2009 48.8 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 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.

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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

(TransCanada's proportionate share)

Year ended December 31 <i>(millions of dollars unless otherwise indicated)</i>	2011	2010	2009
Revenues ⁽¹⁾	817	862	883
Operating expenses	(565)	(564)	(531)
Comparable EBITDA⁽²⁾	252	298	352
Bruce A Comparable EBITDA⁽²⁾	98	91	48
Bruce B Comparable EBITDA⁽²⁾	154	207	304
Comparable EBITDA⁽²⁾	252	298	352
Depreciation and amortization	(113)	(102)	(89)
Comparable EBIT⁽²⁾	139	196	263
Bruce Power Other Information			
Plant availability ⁽³⁾			
Bruce A	90%	81%	78%
Bruce B	88%	91%	91%
Combined Bruce Power	89%	88%	87%
Planned outage days			
Bruce A	60	60	56
Bruce B	135	70	45
Unplanned outage days			
Bruce A	16	64	82
Bruce B	24	34	47
Sales volumes (GWh)			
Bruce A	5,475	5,026	4,894
Bruce B	7,859	8,184	7,767
	13,334	13,210	12,661
Results per MWh			
Bruce A power revenues	\$66	\$65	\$64
Bruce B power revenues ⁽⁴⁾	\$54	\$58	\$64
Combined Bruce Power revenues	\$57	\$60	\$64

(1) Revenues include Bruce A fuel cost recoveries of \$24 million in 2011 (2010 \$29 million; 2009 \$34 million).

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

(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 as well as volumes and revenues associated with deemed generation.

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TransCanada's proportionate share of Bruce Power's Comparable EBITDA decreased \$46 million to \$252 million in 2011 compared to 2010, primarily due to lower results at Bruce B. Comparable EBITDA in 2010 also included the net positive 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.

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TransCanada's proportionate share of Bruce A's Comparable EBITDA increased \$7 million to \$98 million in 2011 compared to 2010 primarily due to higher volumes as a result of a decrease in unplanned outage days, partially offset by the above-noted payment in 2010 from Bruce B.

TransCanada's proportionate share of Bruce B's Comparable EBITDA decreased \$53 million to \$154 million in 2011 compared to 2010. The decrease was primarily due to lower realized prices resulting from expiration of fixed-price contracts at higher prices, higher operating costs and lower volumes due to an increase in planned outage days. Bruce B results for 2010 included the above-noted payment to Bruce A.

Bruce Power's Depreciation and Amortization increased \$11 million in 2011 compared to 2010 and \$13 million in 2010 compared to 2009 primarily due to capital additions.

TransCanada's proportionate share of Bruce Power's Comparable EBITDA of \$298 million in 2010 decreased \$54 million compared to 2009 due to lower realized prices and higher annual lease expense in 2010 for Bruce B, partially offset by higher volumes at both Bruce A and Bruce B and the positive net impact of the payment made in 2010 by Bruce B to Bruce A.

The Independent Electricity System Operator (IESO) periodically requires the curtailment of certain units at Bruce Power to address surplus baseload generation in Ontario. During these unit curtailments, Bruce power receives deemed generation payments at OPA contract prices. Lower sales volumes in 2009 compared to 2010 and 2011 reflected the impact of higher unit curtailments in 2009.

The overall plant availability percentage in 2012 is expected to be in the mid 70s for Bruce A Units 3 and 4. Bruce A commenced the approximate six month West Shift Plus outage on Unit 3 on November 6, 2011. Additional planned maintenance on one of the units at Bruce A is scheduled for the summer of 2012. Bruce B's overall plant availability is expected to be in the mid 90s for the four units in 2012. Planned maintenance on one of the units at Bruce B commenced in January 2012.

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, 2011	March 31, 2012	\$66.33
April 1, 2010	March 31, 2011	\$64.71
April 1, 2009	March 31, 2010	\$64.45

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. Payments received under the floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. No amounts recorded in revenues were subject to repayment in 2011, 2010 or 2009.

Bruce B Floor Price

		per MWh
April 1, 2011	March 31, 2012	\$50.18
April 1, 2010	March 31, 2011	\$48.96
April 1, 2009	March 31, 2010	\$48.76

Bruce B also enters into fixed-price contracts under which it receives or pays the difference between the contract price and the spot price. Bruce B's realized price decreased by \$4 per MWh to \$54 per MWh in 2011 compared to 2010, and by \$6 per MWh to \$58 per MWh in 2010 compared to 2009, and reflected revenues recognized from the floor price mechanism, contract settlements as well as volumes and revenues associated with deemed generation. The decreases reflected the expiration of higher-priced contracts entered into in previous years.

U.S. Power U.S. Power owns approximately 3,800 MW of power generation capacity, consisting of Ravenswood, TC Hydro, Ocean State Power, and Kibby Wind. Ravenswood, located in Queens, New York, 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. 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. Ocean State Power, 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 in service in October 2010.

U.S. Power focuses on selling power under short- and long-term contracts to wholesale, commercial and industrial customers in the New England, New York and PJM Interconnection area (PJM) power markets. Exposure to fluctuations in spot prices on these power sales commitments are hedged with a combination of forward purchases of power, forward purchases of fuel to generate power and through the use of financial contracts.

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. Refer to the Energy Opportunities and Development section of this MD&A for more information.

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, Ocean State Power 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 (<i>millions of U.S. dollars</i>)	2011	2010	2009
Revenues			
Power ⁽³⁾	919	1,090	742
Capacity	227	231	169
Other ⁽³⁾⁽⁴⁾	80	78	79
	1,226	1,399	990
Commodity purchases resold ⁽³⁾	(398)	(543)	(309)
Plant operating costs and other ⁽⁴⁾	(514)	(521)	(471)
General, administrative and support costs	(41)	(32)	(40)
Comparable EBITDA⁽¹⁾	273	303	170
Depreciation and amortization	(109)	(116)	(92)
Comparable EBIT⁽¹⁾	164	187	78

(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 as of October 2009 and October 2010, respectively.

(3) Realized gains and losses from financial derivatives used to purchase and sell power, natural gas and fuel oil to manage U.S. Power's assets are presented on a net basis in Power Revenues.

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

U.S. Power Operating Statistics⁽¹⁾

Year ended December 31	2011	2010	2009
Physical Sales Volumes (GWh)			
Supply			
Generation	6,880	6,755	5,993
Purchased	6,018	8,899	5,310
	12,898	15,654	11,303
Plant Availability⁽²⁾	87%	86%	79%

(1) Includes phases one and two of Kibby Wind as of October 2009 and October 2010, 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 of US\$273 million in 2011 decreased US\$30 million compared to 2010 primarily due to the negative impact of lower commodity and capacity prices and lower physical sales volumes, partially offset by new sales activity in PJM, an increase in the New York commercial customer base and incremental earnings from phase two of Kibby Wind which was placed in service in October 2010.

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Physical sales volumes in 2011 have decreased compared to 2010 due to decreased demand as a result of unseasonable weather and reduced opportunities for wholesale contracts. As well, fewer physical transactions were used to cover power sales commitments during 2011, in favour of financial transactions, compared to 2010.

U.S. Power's Power Revenues of US\$919 million in 2011 decreased US\$171 million compared to 2010 primarily due to lower physical sales volumes and lower prices, partially offset by new sales activity in New York and PJM.

56 MANAGEMENT'S DISCUSSION AND ANALYSIS

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Capacity Revenue of US\$227 million in 2011 decreased US\$4 million compared to 2010. New York capacity revenues in the second half of 2011 were negatively impacted by low spot prices as a result of the price mitigation issue described further in the Energy Opportunities and Developments section in this MD&A. Reduced capacity prices were partially offset by lower forced outage rates at Ravenswood.

Commodity Purchases Resold of \$398 million in 2011 decreased US\$145 million compared to 2010 primarily due to a decrease in the quantity of physical power purchased for resale under U.S. Power's power sales commitments to wholesale and industrial customers in New England, partially offset by higher realized prices on purchased power as well as new activity in the New York and PJM markets.

U.S. Power's Comparable EBITDA of US\$303 million in 2010 increased US\$133 million compared to 2009 primarily due to higher capacity revenues resulting from higher capacity prices partially offset by higher forced outage rates at Ravenswood, higher volumes of power sold in the New England and New York markets, higher realized prices on power sold and incremental earnings from Kibby Wind.

U.S. Power achieved plant availability of 87 per cent in 2011 compared to 86 per cent in 2010 and 79 per cent in 2009. Lower availability in 2009 was primarily due to an unplanned outage at Ravenswood Unit 30 from September 2008 to May 2009.

As at December 31, 2011, approximately 3,600 GWh or 30 per cent and 1,000 GWh or 10 per cent of U.S. Power's planned generation is contracted for 2012 and 2013, respectively. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets. Power sales fluctuate based on customer usage.

Natural Gas Storage 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. TransCanada also has 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 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 TransCanada's 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, 2011, TransCanada had contracted approximately 60 per cent of the total 129 Bcf of working gas storage capacity in 2012 and 20 per cent of storage capacity in 2013. Earnings from third-party storage capacity contracts are recognized over the terms of the contracts.

Proprietary natural gas storage transactions are comprised 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.

These forward natural gas contracts provide highly effective economic hedges but do not meet the specific criteria for hedge accounting and, therefore, are recorded at their fair value based on the forward market prices for the contracted month of delivery. Changes in the fair value of these contracts are recorded in revenues. TransCanada records its proprietary natural gas inventory in storage at its fair value using a weighted average of forward prices for natural gas for the following four months, less selling costs. Changes in the fair value of inventory are recorded in revenues. Changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sales contracts are excluded in determining comparable earnings, as they are not representative of amounts that will be realized on settlement.

Natural Gas Storage's Comparable EBITDA of \$83 million in 2011 decreased \$49 million compared to 2010 primarily due to decreased third party storage and proprietary revenues as a result of lower realized natural gas price spreads.

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

Business Development Business Development Comparable EBITDA losses from business development expenses of \$25 million in 2011 decreased \$7 million compared to 2010 and decreased \$5 million in 2010 compared to 2009 primarily due to decreased development activity in 2011.

ENERGY OPPORTUNITIES AND DEVELOPMENTS

Bruce Power In accordance with terms of the Bruce Power Refurbishment Implementation Agreement (BPRIA) between Bruce Power and the OPA, Bruce A committed to refurbish and restart Units 1 and 2.

Refurbishment work on Units 1 and 2 reached significant milestones in 2011. Fuelling of both Unit 1 and Unit 2 has now been completed and the final phases of commissioning for Unit 2 are underway. Subject to regulatory approval, Bruce Power expects to commence commercial operations of Unit 2 in first quarter 2012 and commercial operations of Unit 1 in third quarter 2012. TransCanada's share of the total net capital cost is expected to be approximately \$2.4 billion of which \$2.3 billion was incurred as at December 31, 2011.

In February 2011, the BPRIA was amended to extend the suspension date for Bruce A Contingent Support Payments (CSP) from December 31, 2011 to June 1, 2012. The CSP received from the OPA by Bruce A are equal to the difference between the fixed prices under the BPRIA and spot market prices. As a result of the amendment, all output from Bruce A will be subject to spot market prices effective June 1, 2012 until the restart of both Units 1 and 2 is complete.

In November 2011, Bruce Power commenced the approximately six month West Shift Plus outage as part of the life extension strategy for Unit 3. Subject to regulatory approval, Unit 3 is expected to return to service in second quarter 2012.

Sundance A In December 2010, Sundance A Units 1 and 2 were withdrawn from service and were subject to a force majeure claim by TransAlta Corporation (TransAlta) in January 2011. In February 2011, TransAlta notified TransCanada that it had determined it was uneconomic to replace or repair Units 1 and 2, and that the Sundance A PPA should therefore be terminated.

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TransCanada has disputed both the force majeure and the economic destruction claims under the binding dispute resolution process provided in the PPA and both matters will be heard through a single binding arbitration process. The arbitration panel has scheduled a hearing in April 2012 for these claims. Assuming the hearing concludes within the time allotted, TransCanada expects to receive a decision in mid-2012.

TransCanada has continued to record revenues and costs throughout 2011 as it considers this event to be an interruption of supply in accordance with the terms of the PPA. The Company does not believe TransAlta's claims meet the tests of force majeure or destruction as specified in the PPA and has therefore recorded \$156 million of EBITDA for the year ended December 31, 2011. The outcome of any arbitration process is not certain, however, TransCanada believes the matter will be resolved in its favour. The Company expects that its unamortized carrying value as at December 31, 2011, of \$77 million related to the Sundance A PPA in Intangibles and Other Assets remains fully recoverable under the terms of the PPA, regardless of the outcome of the arbitration process.

Oakville In October 2010, the Government of Ontario announced that it would not proceed with the \$1.2 billion Oakville generating station, a 900 MW facility that TransCanada was intending to build, own, and operate further to a previously awarded 20-year Clean Energy Supply contract with the OPA. In third quarter 2011, TransCanada, the Government of Ontario and the OPA reached a formal agreement to use an arbitration process to settle the dispute resulting from termination of this contract. Pursuant to the arbitration agreement, the parties remain in discussions. TransCanada expects to be appropriately compensated for the economic consequences associated with the contract's termination.

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

Cartier Wind In November 2011, the 58 MW Montagne-Sèche and the 101 MW first phase of the Gros-Morne Wind farm projects were placed in service. The 111 MW second phase of Gros-Morne is expected to be operational in December 2012. This will complete construction of the 590 MW Cartier Wind project in Québec. All of the power produced by Cartier Wind is sold under a 20-year PPA to Hydro-Québec.

Ontario Solar In December 2011, TransCanada agreed to purchase nine Ontario solar projects from Canadian Solar Solutions Inc., with a combined capacity of 86 MW, for approximately \$470 million. Under the terms of the agreement, each of the nine solar projects will be developed and constructed by Canadian Solar Solutions Inc. using photovoltaic panels. TransCanada will purchase each project once construction and acceptance testing have been completed and operations have begun under 20-year PPAs with the OPA under the Feed-In Tariff program in Ontario. TransCanada anticipates the projects will be placed in service between late 2012 and mid-2013, subject to regulatory approvals.

Bécancour In June 2011, Hydro-Québec notified TransCanada it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant throughout 2012. Under the terms of the suspension agreement, 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 capacity payments under the agreement similar to those that would have been received under the normal course of operation while energy production and payments are suspended.

Ravenswood Since July 2011, spot prices for capacity sales in the New York Zone J market have been negatively impacted by the manner in which NYISO has applied pricing rules for a new power plant that recently began service in this market. TransCanada believes that this application of pricing rules by the NYISO is in direct contravention of a series of the FERC orders which direct how new entrant capacity is to be treated for the purpose of determining capacity prices. TransCanada and other parties have filed formal complaints with the FERC that are currently pending. The outcome of the complaints and longer-term impact that this development may have on Ravenswood is unknown.

During third quarter 2011, the demand curve reset process was completed following the FERC's acceptance of the NYISO's September 22, 2011 compliance filing. This resulted in increased demand curve rates that apply going forward

to 2014. Until the above noted NYISO actions relative to new unit pricing are resolved, capacity prices are expected to remain volatile.

Subsequent to closing the acquisition of Ravenswood in August 2008, TransCanada experienced a forced outage event related to Ravenswood's 981 MW Unit 30. The unit returned to service in May 2009. TransCanada has filed claims against the insurers to enforce its rights under the insurance policies and litigation proceedings are ongoing.

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

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. TransCanada's power generation facilities are exposed to commodity price volatility in its Western Power operations in Alberta and in its U.S. Power operations in New England and New York. Earnings from these businesses are generally correlated to the prevailing power supply demand conditions and the price of natural gas, as power prices are set by gas-fired power supplies the majority of the time. Extended periods of low gas prices will generally place downward pressure on earnings from these facilities. Western Power's Coolidge Generating Station and TransCanada's portfolio of assets in Eastern Canada have been fully contracted, and are therefore not subject to fluctuating commodity prices. Bruce Power's exposure to fluctuating power prices is discussed further below.

Sales of uncontracted power volumes into the spot market in Alberta and the U.S. northeast can be subject to price volatility, directly affecting earnings. To mitigate this risk, TransCanada commits a portion of its supply to medium-term to long-term sales contracts while retaining an amount of unsold supply to mitigate the financial impact of unexpected plant outages and to provide 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. As power sales contracts expire, new forward contracts are entered into at prevailing market prices.

Under an agreement with the OPA, 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. Bruce B also enters into third party fixed-price contracts where it receives the difference between the contract price and spot price. All Bruce A output is sold into the Ontario wholesale power spot market under a fixed-price contract with the OPA. All Bruce A output will be subject to spot market pricing effective June 1, 2012 until the restart of both Units 1 and 2 is complete.

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.

U.S. Power 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, available supply and fluctuations in forecast demand. With the downturn in the economy in recent years, there has been a decrease in demand that, combined with increased supply in these markets, has put downward pressure on capacity prices. In September 2011, the demand curve reset process for the New York Zone J market was completed for the 2011 to 2014 capacity periods, resulting in increased demand curve rates. These increases, however, were more than offset by the unexpected capacity price treatment applied to certain new entrants by NYISO in 2011, a matter that remains subject to a pending complaint lodged with the FERC. Refer to Energy Opportunities and Development for more information.

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 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 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 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, changes in the interpretation and application of market rules by regulators, price caps, emission controls, unfair cost allocations to generators and out-of-market actions taken by others 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 is an active participant in formal and informal regulatory proceedings and takes legal action where required.

Refer to the Risk Management and Financial Instruments and Other Risks sections in this MD&A for information on additional risks related to the Energy business.

ENERGY OUTLOOK

The power supply/demand dynamic in Alberta is rapidly tightening. The 2011 average pool price rose to \$77/MWh compared to \$51/MWh in 2010, driven by unexpected plant outages and increased demand, especially in the peak periods. Increases in Alberta's power demand were a function of economic growth coming from the oil sands and natural gas industries plus population increases in the province. Over the next decade, further oil sands projects and the associated development are expected to drive continued strong Alberta economic growth. The Alberta Electric System Operator's forecasts indicate power demand growth rates of 3.2 per cent per year over the next 20 years and estimates that more than 11,000 MW of new generation will be required. This backdrop will provide an opportunity for TransCanada to participate in new generation and other power infrastructure projects. The current low gas price environment provides an opportunity for gas generation sources to be a very cost-competitive option to fill these anticipated generation needs.

Ontario's 2011 average power demand was down 0.5 per cent compared to 2010. New renewable energy projects came in service in 2011 and the IESO projects a further 2,500 MW of new and refurbished power supply additions by early 2013. This increase in supply, combined with lower natural gas prices plus weak 2011 Ontario economic growth of about two per cent resulted in a decrease in the year-over-year average hourly Ontario energy price from \$36/MWh

in 2010 to \$30/MWh in 2011. The IESO forecasts a return to power demand growth in 2012, however, future power demand growth rates are expected to be modest, as a full return of the energy intensive industries lost in the recession is not expected. TransCanada's existing energy assets in Ontario are largely insulated from changes in the market price of power through contracts with the OPA.

New England's average power demand fell slightly in 2011 while approximately 800 MW of new gas-fired power supply was added. This prevailing supply and demand environment, in addition to lower natural gas prices and weak 2011 economic growth, resulted in power prices down slightly on a year over year basis. The 2011 average ISO New England power price was US\$47/MWh compared to the 2010 average of about US\$50/MWh. ISO New England forecasts a return to power growth of about one per cent per year in the coming years, based on modest economic growth.

New York City's average power demand dropped slightly in 2011 while approximately 550 MW of new gas-fired power supply was added. Under this supply/demand environment, coupled with lower natural gas prices, weak 2011 economic growth and continuing high New York City unemployment rates, power prices fell slightly on a year over year basis. The 2011 average NYISO New York City power price was US\$51/MWh versus the 2010 average of about US\$56/MWh. The NYISO forecasts a return to power demand growth of about one per cent per year in the coming years, based on modest population and economic growth.

Earnings TransCanada expects that results from its Energy operations in 2012 will be higher than those in 2011. There will be a positive earnings impact from a full year of Coolidge, Montagne-Sèche and the first phase of Gros-Morne, which all came in service during 2011. Additional earnings from Bruce Power will also be realized with the return to service of Unit 2, which is expected in first quarter 2012, followed by Unit 1 which is expected in third quarter 2012. It is also anticipated that the nine solar projects TransCanada agreed to purchase in late 2011 will come in service between late 2012 and mid-2013 pending certain conditions and approvals. 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 in service could be tempered by results from U.S. Power if capacity prices in New York remain at low levels, and Gas Storage, where storage spreads are expected to remain at low levels throughout 2012. In addition, earnings from Bruce A will be impacted by the West Shift Plus outage on Unit 3, which commenced on November 6, 2011 and is expected to last six months. Energy earnings in 2012 will also be impacted by fluctuations in Alberta power prices.

Certain regulatory and arbitration outcomes that are expected to be resolved in 2012 may also have a significant impact on Energy results. Specifically, actions taken by the FERC related to New York capacity prices, and resolution to the arbitration processes underway on Sundance A and Oakville may have a material financial impact on Energy earnings in 2012.

Other factors such as plant availability, regulatory changes, weather, currency movements and overall stability of the energy industry can also affect 2012 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.

CORPORATE

Corporate had a Comparable EBIT loss of \$100 million in 2011 compared to losses of \$99 million and \$117 million in 2010 and 2009, respectively. The losses in 2011 were consistent with 2010 and the decrease in the loss in 2010 compared to 2009 was primarily due to lower support services and other corporate costs.

OTHER INCOME STATEMENT ITEMS**COMPARABLE INTEREST EXPENSE**

Year ended December 31 (<i>millions of dollars</i>)	2011	2010	2009
Comparable Interest on long-term debt ⁽¹⁾			
Canadian dollar-denominated	490	514	548
U.S. dollar-denominated	734	680	645
Foreign exchange	(7)	20	92
	1,217	1,214	1,285
Other interest and amortization	24	74	27
Capitalized interest	(302)	(587)	(358)
Comparable Interest Expense	939	701	954

(1) Includes interest on Junior Subordinated Notes.

Comparable Interest Expense increased in 2011 by \$238 million to \$939 million compared to 2010. This increase was primarily due to decreased capitalized interest upon placing Keystone and Coolidge in service in 2011 and Halton Hills in service in the latter part of 2010. Comparable Interest on long-term debt increased in 2011 compared to 2010 primarily due to new debt issues of US\$1.0 billion in September 2010 and US\$1.25 billion in June 2010. This was offset by the impact of a weaker U.S. dollar and the decrease in interest expense on Canadian dollar-denominated debt from debt maturities. Other Interest and Amortization Expense in 2011 was positively affected by increased gains from changes in the fair value of derivatives used to manage TransCanada's exposure to fluctuating interest rates.

Comparable 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. 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 Units 1 and 2.

Comparable Interest Income and Other was \$60 million in 2011 compared to \$94 million and \$121 million in 2010 and 2009, respectively. The decrease in 2011 compared to 2010 was primarily due to lower gains from derivatives used to manage the Company's exposure to foreign exchange rate fluctuations. The decrease in 2010 compared to 2009 was primarily due to the positive impact of a weakening U.S. dollar on the translation of U.S. dollar working capital balances throughout each year and gains in 2010 on derivatives used to manage foreign exchange fluctuations.

Comparable Income Taxes were \$595 million, \$400 million and \$406 million in 2011, 2010, and 2009, respectively. The increase of \$195 million in 2011 compared to 2010 was primarily due to increased pre-tax earnings and higher positive income tax adjustments in 2010 compared to 2011. In 2011 and 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 the Bison pipeline which was placed in service in January 2011 and the Wood River/Patoka and Cushing Extension sections of Keystone which were placed in operational service in June 2010 and February 2011, respectively. The decrease of \$6 million in 2010 compared to 2009 was primarily due to increased pre-tax earnings offset by higher positive income tax adjustments in 2010.

Non-Controlling Interests were \$129 million in 2011 compared to \$115 million and \$96 million in 2010 and 2009, respectively. The \$14 million increase in 2011 compared to 2010 was primarily due to the sale of a 25 per cent interest in GTN and Bison to TC PipeLines, LP and reduction in the Company's ownership interest in TC PipeLines, LP in May 2011 partially offset by the impact of a weaker US dollar in 2011. The increase in 2010 compared to 2009 was primarily due to increased TC PipeLines, LP earnings as a result of higher revenues from Northern Border and the acquisition by TC PipeLines, LP of North Baja, partially offset by the impact of a weaker US dollar in 2010.

LIQUIDITY AND CAPITAL RESOURCES

TransCanada believes that its financial position remains sound 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 is underpinned by predictable cash flow from operations, available cash balances and unutilized committed revolving bank lines of US\$1.0 billion, \$2.0 billion, US\$1.0 billion and US\$300 million, maturing in November 2012, October 2016, October 2012 and February 2013, respectively. These facilities also support the Company's three commercial paper programs. In addition, at December 31, 2011, TransCanada's proportionate share of unutilized capacity on committed bank facilities at TransCanada-operated affiliates was \$0.1 billion with maturity dates in 2012 and 2016. As at December 31, 2011, TransCanada had capacity of \$2.0 billion, \$1.25 billion and US\$4.0 billion under its equity, Canadian debt and U.S. debt shelf prospectuses, respectively. 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 (<i>millions of dollars</i>)	2011	2010	2009
Funds generated from operations ⁽¹⁾	3,663	3,331	3,080
Decrease/(Increase) in operating working capital	310	(249)	(90)
Net Cash Provided by Operations	3,973	3,082	2,990

(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 \$15 billion over the three-year period ending December 31, 2011.

Dividends

TransCanada's Board of Directors declared a \$0.44 per common share dividend for the quarter ending March 31, 2012, 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, 2012 and \$0.275 per Series 5 preferred share for the three-month period ending April 30, 2012.

CASH FLOW AND CAPITAL RESOURCES

Cash Generated from Operations

Net Cash Provided by Operations was \$4.0 billion in 2011 compared to \$3.1 billion and \$3.0 billion in 2010 and 2009, 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 \$3.7 billion in 2011 compared to \$3.3 billion and \$3.1 billion in 2010 and 2009, respectively. The increase in 2011 compared to 2010 was primarily due to increased cash from earnings. This increase was net of lower current income tax benefits from bonus depreciation for U.S. tax purposes recognized in 2011 compared to 2010. The increase in 2010 compared to 2009 was primarily due to the current income tax benefit generated from bonus depreciation for U.S. tax purposes on Keystone assets placed in service in June 2010.

As at December 31, 2011, TransCanada's current liabilities were \$5.9 billion and current assets were \$3.6 billion resulting in a working capital deficiency of \$2.3 billion. The Company believes this shortfall can be managed through its ability to generate cash flow from operations, access to the unutilized committed revolving bank lines in excess of \$4.0 billion, discussed above, as well as its ongoing access to capital markets.

Investing Activities

Capital expenditures totalled \$3.3 billion in 2011 compared to \$5.0 billion in 2010 and \$5.4 billion in 2009. Expenditures in 2011, 2010 and 2009 related primarily to the completion of the Wood River/Patoka and Cushing Extension Sections of Keystone, advancement of Keystone XL, the refurbishment and restart of Units 1 and 2 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.

Financing Activities

In 2011, TransCanada issued Medium-Term Notes of \$500 million and \$250 million maturing in 2021 and 2041, respectively, and US\$350 million of Senior Notes due in 2021. The Company also made draws totalling US\$0.5 billion on existing facilities and retired or repaid \$1.3 billion of long-term debt.

In 2011, the Company's proportionate share of joint venture long-term debt issued and repaid was \$48 million and \$102 million, respectively. In addition, Notes Payable decreased by \$218 million in 2011.

At December 31, 2011, 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, extendible TransCanada PipeLines Limited (TCPL) credit facility, maturing October 2016. The facility was fully available at December 31, 2011 and supports TCPL's Canadian commercial paper program;

a US\$300 million committed, syndicated, revolving credit facility maturing February 2013. At December 31, 2011, this facility was fully available. This facility is part of an initial US\$1.0 billion TransCanada PipeLine USA Ltd. (TCPL USA) credit facility established in 2007 which has since been reduced through term loan repayments of US\$200 million in August 2011 and US\$500 million in January 2012;

a US\$1.0 billion committed, syndicated, revolving, extendible TransCanada Keystone Pipeline, LP credit facility, maturing November 2012. The facility was fully available at December 31, 2011 and supports a TCPL USA U.S. dollar commercial paper program dedicated to funding a portion of capital expenditures for Keystone;

a US\$1.0 billion committed, syndicated, revolving, extendible TCPL USA credit facility, maturing October 2012. The facility was fully available at December 31, 2011 and supports a TCPL U.S. dollar commercial paper program that was established in December 2011; and

demand lines totalling \$802 million, which support the issuance of letters of credit and provide additional liquidity. At December 31, 2011, the Company had used approximately \$468 million of these demand lines for letters of credit.

In May 2011, TransCanada sold a 25 per cent interest in each of GTN LLC and Bison LLC to TC PipeLines, LP for a total transaction value of US\$605 million, which included US\$81 million of long-term debt, or 25 per cent of GTN LLC debt outstanding. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively. Subsequent to the transaction, TransCanada's ownership in TC PipeLines, LP decreased to 33.3 per cent due to TC PipeLines, LP's public issuance of common units as discussed under the heading 2011 Equity Financing Activities in this section.

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

2011 Long-Term Debt Financing Activities

In November 2011, the Company issued Medium-Term Notes of \$500 million and \$250 million maturing in 2021 and 2041, respectively, and in June 2011, TC Pipelines, LP issued US\$350 million of Senior Notes due in 2021. The Company also made draws totalling US\$0.5 billion on existing facilities and retired or repaid \$1.3 billion of long-term debt.

2011 Equity Financing Activities

In November 2011, TransCanada filed a base shelf prospectus in Canada and the U.S. qualifying the issuance of up to \$2.0 billion of common shares, preferred shares and/or subscription receipts until December 2013. The shelf replaced the base shelf prospectus filed in September 2009. No securities have been issued under the November 2011 base shelf prospectus.

In May 2011, TC PipeLines, LP completed an underwritten public offering of 7,245,000 common units, including 945,000 common units purchased by the underwriters upon full exercise of an over-allotment option, at US\$47.58 per unit. As part of this offering, TransCanada made a capital contribution of approximately US\$7 million to maintain its two per cent general partnership interest in TC PipeLines, LP and did not purchase any other units. As a result of the common units offering, TransCanada's ownership in TC PipeLines, LP decreased from 38.2 per cent to 33.3 per cent.

Dividend Reinvestment and Share Purchase Plan

TransCanada's Board of Directors has authorized the issuance of common shares 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 Company reserves the right to satisfy its DRP obligations by issuing common shares from treasury at a discount of up to five per cent or by purchasing shares on the open market. Commencing with the dividends declared in April 2011, common

shares purchased with reinvested cash dividends are satisfied with shares acquired on the open market at 100 per cent of the weighted average purchase price. Previously, common shares purchased with reinvested cash dividends were satisfied with shares issued from treasury 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. In 2011, dividends of \$202 million were paid (2010 \$378 million; 2009 \$254 million) through the issuance of 5 million (2010 11 million; 2009 8 million) common shares from treasury in accordance with the DRP.

Dividends

Cash dividends on common shares of \$961 million were paid in 2011 (2010 \$710 million; 2009 \$722 million). In addition, cash dividends of \$55 million were paid on preferred shares in 2011 (2010 \$44 million). The increase in common share cash dividends paid in 2011 was primarily due to the Company's decision to satisfy its DRP obligations with market purchased shares instead of treasury shares effective April 2011, as discussed above, and an increase in the per share dividend amount in 2011. The decrease in common share dividends paid in cash in 2010 from 2009 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 per share dividend amount in 2010.

The increase in preferred share dividends paid in 2011 from 2010 was primarily due to a full year of preferred share dividend payments in 2011 on preferred shares issued in March and June 2010. 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 2012, TransCanada's Board of Directors approved an increase in the quarterly common share dividend payment to \$0.44 per share from \$0.42 per share for the quarter ending March 31, 2012. This was the twelfth 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, 2012 and \$0.275 per Series 5 preferred share for the three-month period ended April 30, 2012.

CONTRACTUAL OBLIGATIONS

Obligations and Commitments

At December 31, 2011, the Company had \$18.6 billion of total long-term debt and \$1.0 billion of Junior Subordinated Notes, compared to \$17.9 billion of total long-term debt and \$1.0 billion of Junior Subordinated Notes at December 31, 2010. TransCanada's share of the total long-term debt of joint ventures, including capital lease obligations, was \$0.8 billion at December 31, 2011, compared to \$0.9 billion at December 31, 2010. Total Notes Payable, including TransCanada's proportionate share of the notes payable of joint ventures, were \$1.9 billion at December 31, 2011 and \$2.1 billion at December 31, 2010. TransCanada has also provided certain pro-rata guarantees related to the capital lease and performance obligations of Bruce Power and certain other partially owned entities.

CONTRACTUAL OBLIGATIONS

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
Long-term debt ⁽¹⁾	20,204	950	1,926	2,467	14,861
Capital lease obligations	194	18	42	57	77
Operating leases ⁽²⁾	735	79	152	143	361
Purchase obligations	9,152	1,650	2,905	1,568	3,029
Other long-term liabilities reflected on the balance sheet	911	17	35	39	820
	31,196	2,714	5,060	4,274	19,148

(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 2011 was \$394 million (2010 \$363 million; 2009 \$384 million).

At December 31, 2011, 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

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
Long-term debt	18,567	935	1,874	2,311	13,447
Junior subordinated notes	1,009				1,009
Long-term debt of joint ventures	628	15	52	156	405
	20,204	950	1,926	2,467	14,861

INTEREST PAYMENTS

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

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Long-term debt	16,541	1,180	2,227	1,989	11,145
Junior subordinated notes ⁽¹⁾	355	65	129	129	32
Long-term debt of joint ventures	343	48	89	77	129
	17,239	1,293	2,445	2,195	11,306

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

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At December 31, 2011, the Company's approximate future purchase obligations were as follows:

PURCHASE OBLIGATIONS⁽¹⁾

Year ended December 31 <i>(millions of dollars)</i>	Payments Due by Period				
	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Natural Gas Pipelines					
Transportation by others ⁽²⁾	482	130	133	108	111
Capital expenditures ⁽³⁾⁽⁴⁾	250	248	2		
Other	1	1			
Oil Pipelines					
Capital expenditures ⁽³⁾⁽⁵⁾	992	98	894		
Other	48	4	8	8	28
Energy					
Commodity purchases ⁽⁶⁾	5,121	666	1,201	1,221	2,033
Capital expenditures ⁽³⁾⁽⁷⁾	290	234	56		
Other ⁽⁸⁾	1,928	254	587	231	856
Corporate					
Information technology and other	40	15	24		1
	9,152	1,650	2,905	1,568	3,029

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

(2) Rates are based primarily on known 2011 levels. Beyond 2011, 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, if required, 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 primarily relate to Keystone XL.

(6) Commodity purchases include fixed and variable components and excludes derivatives. 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. This includes the purchase obligation for Ontario Solar.

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 2012, TransCanada expects to make funding contributions of approximately \$119 million to its defined benefit pension plans (DB Plan) and approximately \$31 million to the Company's other post-retirement benefit plans, savings plan and defined contribution pension plans. In addition

to these contributions, the Company expects to provide a

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\$48 million letter of credit in 2012 to the DB Plan. In 2011, the Company made total cash funding contributions of \$93 million and provided a \$27 million letter of credit to the DB Plan. TransCanada's proportionate share of cash funding contributions expected to be made by joint ventures to their respective pension and other post-retirement benefit plans in 2012 is approximately \$73 million and \$7 million, respectively, compared to total contributions of \$59 million in 2011.

The next actuarial valuation for the Company's pension and other post-retirement benefit plans will be carried out as at January 1, 2013. Based on current market conditions, TransCanada expects funding requirements for these plans to continue at the anticipated 2012 level for the next several years to amortize solvency deficiencies in addition to normal costs. The Company's 2012 net benefit cost is expected to increase from 2011 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 \$95 million. The Company expects \$88 million and \$7 million to be paid in 2012 and 2013, respectively.

Ontario Solar

In December 2011, an agreement was announced for the purchase of nine Ontario solar projects with a combined capacity of 86 MW, for approximately \$470 million. TransCanada will purchase each project once construction and acceptance testing are completed and operations have begun under 20-year PPAs with the OPA under the Feed-In Tariff program in Ontario. It is anticipated that the projects will be placed in service between late 2012 and mid-2013, subject to regulatory approvals.

Contingencies

TransCanada is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2011, the Company had accrued approximately \$49 million (2010 \$59 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, arbitrations and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

In December 2010, Sundance A Units 1 and 2 were withdrawn from service and were subject to a force majeure claim by TransAlta in January 2011. In February 2011, TransAlta notified TransCanada that it had determined it was uneconomic to replace or repair Units 1 and 2, and that the Sundance A PPA should therefore be terminated. TransCanada has disputed both the force majeure and the economic destruction claims under the binding dispute resolution process provided in the PPA and both matters will be heard through a single binding arbitration process. The arbitration panel has scheduled a hearing in April 2012 for these claims. Assuming the hearing concludes within the time allotted, TransCanada expects to receive a decision in mid-2012. TransCanada has continued to record revenues and costs throughout 2011 as it considers this event to be an interruption of supply in accordance with the terms of the PPA. The Company does not believe TransAlta's claims meet the tests of force majeure or destruction as specified in the PPA and has therefore recorded \$156 million of EBITDA for the year ended December 31, 2011. The outcome of any arbitration process is not certain, however, TransCanada believes the matter will be resolved in its favour.

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 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 \$863 million at December 31, 2011. The fair value of these Bruce Power guarantees at December 31, 2011 is estimated to be \$29 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 assurances was estimated at December 31, 2011 to range from \$182 million to a maximum of \$498 million. The fair value of these guarantees at December 31, 2011 is estimated to be \$7 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 financial 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 and natural gas. 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 operational and price risks in its asset portfolio.

The Company purchases a portion of the natural gas 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.

The Company's power sales commitments are 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.

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 interest rates.

A portion of TransCanada's earnings from its Natural Gas Pipelines, Oil 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, 2011, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of \$10 billion (US\$9.8 billion) (2010 \$9.8 billion (US\$9.8 billion)) and a fair value of \$12.7 billion (US\$12.5 billion) (2010 \$11.3 billion (US\$11.4 billion)). At December 31, 2011, \$79 million (December 31, 2010 nil)

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was included in Other Current Assets, \$66 million (December 31, 2010 \$181 million) was included in Intangibles and Other Assets, \$15 million (December 31, 2010 nil) was included in Accounts Payable, and \$41 million (December 31, 2010 nil) was included in Deferred Amounts for the fair value of the forwards and swaps 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)	2011		2010	
	Fair Value ⁽¹⁾	Notional or Principal Amount	Fair Value ⁽¹⁾	Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2012 to 2018)	93	US 3,850	179	US 2,800
U.S. dollar forward foreign exchange contracts (maturing 2012)	(4)	US 725	2	US 100
	89	US 4,575	181	US 2,900

(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, 2011 (2010 \$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 the financial instruments 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 contract 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, portfolio investments recorded at fair value, the fair value of derivative assets and notes, loans and advances receivable. The carrying amounts and fair values of these financial assets, except amounts for derivative assets, are included in Accounts receivable and other, and Available for sale assets in the Non-Derivative Financial Instruments Summary table located in the Fair Values section of this note. The majority of counterparty credit exposure is with counterparties that are investment grade or the exposure is supported by financial assurances provided by investment grade parties. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At December 31, 2011, there were no significant amounts past due or impaired, and there were no significant credit losses during the year.

At December 31, 2011, the Company had a credit risk concentration of \$274 million (2010 \$317 million) due from a counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

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.

In August 2011, the Company received final distributions of 2.1 million common shares, as a result of previous claims in the 2005 Calpine Corporation bankruptcy. These shares were sold into the open market resulting in total pre-tax gains of \$30 million, of which the Company had accrued pre-tax gains of \$15 million in 2010. In 2008, the Company had received 15.5 million common shares which were sold into the open market for \$279 million. Claims by NGTL and Foothills PipeLines (South B.C.) Ltd. for \$32 million and \$44 million, respectively, were received in cash in 2008 and 2009 and were passed onto the shippers on these systems in 2008 and 2009.

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, 2011, the Company had unutilized committed revolving bank lines of US\$1.0 billion, US\$1.0 billion, US\$300 million and \$2.0 billion maturing in October 2012, November 2012, February 2013 and October 2016, respectively. The Company has also maintained continuous access to the Canadian commercial paper market on competitive terms and recently initiated a commercial paper program in the U.S.

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 2011, 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 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:

<i>December 31 (millions of dollars)</i>	2011	2010
Notes payable	1,863	2,081
Long-term debt	18,567	17,922
Junior subordinated notes	1,009	985
Cash and cash equivalents	(654)	(660)
Net Debt	20,785	20,328
Equity attributable to non-controlling interests	1,465	1,157
Equity attributable to controlling interests	17,324	16,727
Total Equity	18,789	17,884
	39,574	38,212

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 and natural gas 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. The fair value of 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:

December 31 (<i>millions of dollars</i>)	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial Assets⁽¹⁾				
Cash and cash equivalents	765	765	764	764
Accounts receivable and other ⁽²⁾⁽³⁾	1,576	1,620	1,555	1,595
Available for sale assets ⁽²⁾	23	23	20	20
	2,364	2,408	2,339	2,379
Financial Liabilities⁽¹⁾⁽³⁾				
Notes payable	1,880	1,880	2,092	2,092
Accounts payable and deferred amounts ⁽⁴⁾	1,536	1,536	1,436	1,436
Accrued interest	373	373	367	367
Long-term debt	18,567	23,757	17,922	21,523
Junior subordinated notes	1,009	1,027	985	992
Long-term debt of joint ventures	822	940	866	971
	24,187	29,513	23,668	27,381

(1) Consolidated Net Income in 2011 included losses of \$13 million (2010 losses of \$8 million) for fair value adjustments related to interest rate swap agreements on US\$350 million (2010 US\$250 million) of Long-Term Debt. There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

(2) At December 31, 2011, the Consolidated Balance Sheet included financial assets of \$1,265 million (2010 \$1,271 million) in Accounts Receivable, \$41 million (2010 \$40 million) in Other Current Assets and \$293 million (2010 \$264 million) in Intangibles and Other Assets.

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

(4) At December 31, 2011, the Consolidated Balance Sheet included financial liabilities of \$1,494 million (2010 \$1,406 million) in Accounts Payable and \$42 million (2010 \$30 million) in Deferred Amounts.

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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, 2011:

Contractual Repayments of Financial Liabilities⁽¹⁾

<i>(millions of dollars)</i>	Total	Payments Due by Period			
		2012	2013 and 2014	2015 and 2016	2017 and Thereafter
Notes payable	1,880	1,880			
Long-term debt	18,567	935	1,874	2,311	13,447
Junior subordinated notes	1,009				1,009
Long-term debt of joint ventures	822	33	94	213	482
	22,278	2,848	1,968	2,524	14,938

(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

<i>(millions of dollars)</i>	Total	Payments Due by Period			
		2012	2013 and 2014	2015 and 2016	2017 and Thereafter
Long-term debt	16,541	1,180	2,227	1,989	11,145
Junior subordinated notes	355	65	129	129	32
Long-term debt of joint ventures	343	48	89	77	129
	17,239	1,293	2,445	2,195	11,306

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2011, excluding hedges of the Company's net investment in self-sustaining foreign operations, is as follows:

December 31 (all amounts in millions unless otherwise indicated)	2011			
	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading⁽¹⁾				
Fair Values ⁽²⁾				
Assets	\$213	\$176	\$3	\$22
Liabilities	\$(212)	\$(212)	\$(14)	\$(22)
Notional Values				
Volumes ⁽³⁾				
Purchases	23,500	103		
Sales	23,158	82		
Canadian dollars				684
U.S. dollars			US 1,269	US 250
Cross-currency			47/US 37	
Net unrealized (losses)/gains in the year ⁽⁴⁾	\$(3)	\$(50)	\$(4)	\$1
Net realized gains/(losses) in the year ⁽⁴⁾	\$58	\$(74)	\$10	\$10
Maturity dates	2012-2018	2012-2016	2012	2012-2016
Derivative Financial Instruments in Hedging Relationships⁽⁵⁾⁽⁶⁾				
Fair Values ⁽²⁾				
Assets	\$42	\$3	\$	\$13
Liabilities	\$(277)	\$(22)	\$(38)	\$(1)
Notional Values				
Volumes ⁽³⁾				
Purchases	17,188	8		
Sales	9,217			
U.S. dollars			US 91	US 600
Cross-currency			136/US 100	
Net realized losses in the year ⁽⁴⁾	\$(150)	\$(17)	\$	\$(16)
Maturity dates	2012-2017	2012-2013	2012-2014	2012-2015

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

(2) Fair values equal carrying values.

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

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

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of \$13 million and a notional amount of US\$350 million. In 2011, net realized gains on fair value hedges were \$7 million and were included in Interest Expense. In 2011, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6)

In 2011, Net Income included losses of \$3 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 2011, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts have been excluded from the assessment of hedge effectiveness.

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The anticipated timing of settlement of the derivative contracts assumes constant commodity prices, interest rates and foreign exchange rates from December 31, 2011. 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:

<i>(millions of dollars)</i>	Total	2012	2013 and 2014	2015 and 2016	2017 and Thereafter
Derivative financial instruments held for trading					
Assets	414	282	123	9	
Liabilities	(460)	(292)	(151)	(17)	
Derivative financial instruments in hedging relationships					
Assets	217	121	91	5	
Liabilities	(408)	(208)	(135)	(50)	(15)
	(237)	(97)	(72)	(53)	(15)

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Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2010, excluding hedges of the Company's net investment in self-sustaining foreign operations, is as follows:

<i>December 31 (all amounts in millions unless otherwise indicated)</i>	2010			
	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 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 the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of \$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 relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. 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)	2011	2010
Current		
Other current assets	404	273
Accounts payable	(502)	(337)
Long Term		
Intangibles and other assets (Note 9)	213	374
Deferred amounts (Note 11)	(352)	(282)

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 derivatives was \$35 million at December 31, 2011 (2010 \$48 million). These contracts mature from 2012 to 2018. The Company's proportionate share of the notional sales volumes of power associated with this exposure was 2,979 GWh at December 31, 2011 (2010 3,772 GWh). The Company's proportionate share of the notional purchased volumes of power associated with this exposure was 1,595 GWh at December 31, 2011 (2010 2,322 GWh).

Derivatives in Cash Flow Hedging Relationships

Information about how derivatives and hedging activities affect the Company's financial position, financial performance and cash flows is as follows:

	Cash Flow Hedges							
	Power		Natural Gas		Foreign Exchange		Interest	
Year ended December 31 (millions of Canadian dollars, pre-tax)	2011	2010	2011	2010	2011	2010	2011	2010
Change in fair value of derivative instruments recognized in OCI (effective portion)	(252)	(79)	(59)	(26)	5	10	(1)	(137)
Reclassification of gains and losses on derivative instruments from AOCI to Net Income (effective portion)	61	(7)	100	(21)			43	32

Credit Risk Related Contingent Features

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. Based on contracts in place and market prices at December 31, 2011, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was \$110 million (2010 \$92 million), for which the Company has provided collateral of \$28 million (2010 \$4 million) in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on December 31, 2011, the Company would have been required to provide additional collateral of \$82 million (2010 \$88 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative financial instruments exceed pre-defined contractual exposure limit thresholds. The Company has sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Fair Value Hierarchy

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

There were no transfers between Level I and Level II in 2011 or 2010. 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	
	2011	2010	2011	2010	2011	2010	2011	2010
December 31 (millions of dollars, pre-tax)	2011	2010	2011	2010	2011	2010	2011	2010
Natural Gas Inventory			29	49			29	49
Derivative Financial Instrument Assets:								
Interest rate contracts			35	28			35	28
Foreign exchange contracts	11	10	131	179			142	189
Power commodity contracts			244	269	2	5	246	274
Gas commodity contracts	124	93	55	56			179	149
Derivative Financial Instrument Liabilities:								
Interest rate contracts			(23)	(47)			(23)	(47)
Foreign exchange contracts	(13)	(11)	(89)	(54)			(102)	(65)
Power commodity contracts			(465)	(299)	(15)	(8)	(480)	(307)
Gas commodity contracts	(208)	(178)	(26)	(15)			(234)	(193)
Non-Derivative Financial Instruments:								
Available-for-sale assets	23	20					23	20
	(63)	(66)	(109)	166	(13)	(3)	(185)	97

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

<i>(millions of dollars, pre-tax)</i>	Derivatives ⁽¹⁾
Balance at December 31, 2009	(2)
New contracts ⁽²⁾	(16)
Settlements	(3)
Transfers into Level III ⁽³⁾	3
Transfers out of Level III ⁽³⁾⁽⁴⁾	(38)
Change in unrealized gains recorded in Net Income	14
Change in fair value of derivative instruments recorded in OCI	39
<hr/>	
Balance at December 31, 2010	(3)
New contracts⁽²⁾	1
Settlements	1
Transfers out of Level III⁽³⁾⁽⁴⁾	(1)
Change in unrealized gains recorded in Net Income	1
Change in fair value of derivative instruments recorded in OCI	(12)
<hr/>	
Balance at December 31, 2011	(13)

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

(2) At December 31, 2011, 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 nil (2010 - \$1 million).

(3) 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.

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

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a \$10 million decrease or increase, respectively, in the fair value of outstanding derivative financial instruments included in Level III as at December 31, 2011.

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.

Operational and Other Business Risks

There are a number of operating risks associated with TransCanada's pipelines and energy businesses including: labour disputes; the breakdown or failure of equipment; acts of terror; and catastrophic events such as natural disasters. The occurrence or continuance of any of these events could impact earnings through the costs associated with remediation or a reduction in revenues.

The Company has established emergency response plans to address certain unplanned events, which include an ongoing program to provide local emergency responders with the information and training necessary to ensure their preparedness for responding to events. TransCanada maintains a comprehensive insurance program to mitigate the risk of potential losses arising from operational risks and other potential losses related to its business. In certain circumstances, not all events will be covered by insurance, which may have an adverse effect on the Company's operations, earnings, cash flow and financial position.

Health, Safety and Environment Risk Management

Health, safety and environment (HSE) are top priorities in all of TransCanada's operations and business activities. These areas are guided by the Company's HSE 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 HSE 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 the public and the environment. The Company is committed to continually improving its HSE 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 and expectation on HSE performance and will influence them to improve their collective performance and culture. TransCanada is committed to respecting the diverse environments and cultures in which it operates and to supporting open communication with its stakeholders.

The HSE Committee of TransCanada's Board of Directors monitors compliance with the Company's HSE corporate policy through regular reporting. TransCanada's integrated HSE management system is modeled after the International Organization for Standardization (ISO) standard for environmental management systems, ISO 14001; and the Occupational Health and Safety Assessment Series (OHSAS 18001) for occupational health and safety. TransCanada's HSE management system conforms to external industry consensus standards and voluntary regulatory programs and complies with applicable legislated requirements and various other internal management systems. Resources are focused on the areas of significant risk to the organization's HSE business activities. Management is informed regularly of all important and/or significant HSE operational issues and initiatives through formal reporting and incident management processes. TransCanada's HSE management system and performance are assessed by an independent outside firm every three years. The most recent assessment occurred in 2009 and did not identify any material issues. The HSE management system is subject to ongoing internal and external 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 2011, one of the Company's objectives was to sustain health and safety performance year over year. Overall, the Company's safety frequency rates in 2011 continued to be better than most industry benchmarks.

The safety and integrity of the Company's existing and newly-developed infrastructure is also a top priority. All new assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are brought in service only after all necessary requirements have been satisfied. The Company expects to spend approximately \$322 million in 2012 for pipeline integrity on the pipelines it operates, an increase of approximately \$78 million over 2011 primarily due to increased levels of in-line pipeline inspection on all systems. 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. TransCanada's pipeline safety record in 2011 continued to be better than industry benchmarks. TransCanada experienced two pipeline breaks in 2011 on its operated pipelines. The first break occurred in a remote part of Northern Ontario on the Canadian Mainline pipeline system. The second break occurred in a remote part of Wyoming on the Bison pipeline system.

Spending associated with public safety on the Energy assets is focused primarily on the Company's hydro dams and associated equipment, and is slightly higher than previous years due to increased spending to repair damage from the high flow events of 2011 caused by Hurricane Irene.

Environment

TransCanada's facilities are subject to stringent federal, state, provincial, and local environmental statutes and regulations governing environmental protection, including, but not limited to, air emissions, water quality, wastewater discharges and waste management. Such laws and regulations generally require facilities to obtain or comply with a wide variety of environmental registrations, licences, permits and other approvals and requirements. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, the imposition of remedial requirements and/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.

At December 31, 2011, TransCanada recorded liabilities of approximately \$69 million (2010 \$84 million) for remediation obligations and compliance costs associated with certain 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.

The Company owns assets in four regions, Alberta, Québec, B.C., and the Northeastern U.S., where regulations exist to address industrial greenhouse gas (GHG) emissions. TransCanada has procedures in place to comply with these regulations.

In Alberta, under the *Specified Gas Emitters Regulation*, industrial facilities emitting GHG emissions over an intensity threshold level are required to reduce the intensity of GHG emissions 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 certain rights under the PPAs. TransCanada has a program in place to manage the compliance costs incurred by these assets as a result of the regulation. Compliance costs on the Alberta System are recovered through tolls 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 GHG emissions related costs of \$13 million for 2011 (2010 \$22 million), 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 2011, 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 carbon tax in B.C., which came into effect in mid-2008, applies to carbon dioxide (CO₂) 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 2011 were approximately \$3 million (2010 \$4 million). The cost per tonne of CO₂ will be increased in July 2012 to \$30 from \$25.

States in the northeastern U.S. that are members of the Regional Greenhouse Gas Initiative (RGGI) implemented a CO₂ cap-and-trade program for electricity generators effective in January 2009. Under the RGGI, both the Ravenswood and OSP generation facilities were 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 Ocean

State Power generation facilities and incurred related costs of \$4 million in 2011 (2010 \$5 million). These costs were generally recovered through the power market and the net impact on TransCanada was not significant.

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.

Environmental risks from TransCanada's operating facilities typically include: air emissions, GHG emissions; potential impacts on land, including land reclamation or restoration following construction; the use, storage and release of hydrocarbons or other chemicals; the generation, handling and disposal of wastes and hazardous wastes; and water impacts such as uncontrolled water discharge.

The Company'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 contaminated sites or additional information at existing contaminated 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.

The impact of new or proposed federal, state, and/or provincial 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 for 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.

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 enhanced 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 federal, regional, state, 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 and/or regional climate change regulations to manage industrial GHG emissions.

In August 2011, the Canadian government published the first sector specific draft regulation that will impact industrial GHG emissions. This proposed regulation is focused on the coal-fired generation of electricity and requires a natural gas performance standard for all coal-fired facilities reaching the end of their economic life. The draft regulation is expected to come into effect in July 2015. This process is not expected to pose a significant risk or financial impact to TransCanada's existing facilities and may present opportunities for new power generation investment. Additional sectors,

including the natural gas-fired generation of electricity and upstream oil and gas facility sectors, are expected to begin consultations with Environment Canada.

The Western Climate Initiative (WCI) continues to work toward implementing a regional cap-and-trade program. California and Québec are the only WCI members with cap and trade regulations. In December 2011, the Government of Québec adopted the "Regulation respecting the cap-and-trade system for greenhouse gas emission allowances". The initial phase of the cap and trade system will begin January 1, 2013. The regulation will have a limited impact on TransCanada's Bécancour power generation facility and natural gas pipeline assets. With respect to California, the Air Resources Board adopted a cap and trade regulation in October 2011. The regulation is divided into two phases: the first, beginning in 2013, will include all major industrial sources and electricity utilities; the second, starting in 2015, will cover distributors of transportation fuels, natural gas and other fuels. The regulation may impact the Company's importation of electricity into the state.

Future Abandonment Costs

Depending 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 recognizes the fair value of a liability for asset retirement obligations (ARO), which is accreted through changes to operating expenses. The Company recorded ARO 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 ARO include scope of abandonment and reclamation activities, inflation rates, discount rates and timing of asset retirements. By their nature, these assumptions are subject to measurement uncertainty. The Company has determined that the scope and timing of asset retirements related to its U.S. regulated natural gas pipelines, oil pipelines and hydroelectric power plants is indeterminable. As a result, the Company has not recorded amounts for ARO related to these assets, with the exception of certain abandoned facilities.

The NEB's LMCI 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 filed its estimates of abandonment costs for its Canadian oil and natural gas pipelines in November 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. In addition, as the actual timing of retirements for the assets is indeterminable, the Company has not recorded amounts for ARO.

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, 2011, 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, 2011, 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 CGAAP, including a reconciliation to U.S. generally accepted accounting principles (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, 2011, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

In 2011, 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 2011 reports filed with the SEC and the Canadian securities regulators.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

To prepare financial statements that conform with CGAAP, 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. A summary of TransCanada's significant accounting policies can be found in Note 2 to the Consolidated Financial Statements. 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 CGAAP. 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 (RRA) 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 CGAAP in order to appropriately reflect the economic impact of the regulators' decisions regarding the Company's revenues and tolls. At December 31, 2011, the Company reported regulatory assets of \$0.2 billion and \$1.4 billion in Other Current Assets and Regulatory Assets, respectively (2010 \$0.3 billion and \$1.5 billion, respectively), and regulatory liabilities of \$0.1 billion and \$0.3 billion in Accounts Payable and Regulatory Liabilities, respectively (2010 \$0.1 billion and \$0.3 billion, respectively).

Financial Instruments and Hedges

Financial Instruments

The Company initially records all financial instruments on the Balance Sheet at 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.

Held for trading derivative financial assets and liabilities consist of swaps, options, forwards and futures with changes in the fair value recorded in Net Income. 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 with changes in the fair value recorded in Other Comprehensive (Loss)/Income (OCI). 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 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 arrangements that qualify for hedge accounting treatment, which include fair value and cash flow hedges, and 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 or cancellation.

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 initially recognized in OCI, 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 it is probable the anticipated transaction will not occur.

The Company also enters into cash flow hedges and fair value hedges for activities subject to rate regulation in Canada. 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 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 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 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 in certain circumstances, fluctuations can result in variability in Net Income.

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 2011 was \$1,528 million (2010 \$1,354 million; 2009 \$1,377 million) and was recorded in Natural Gas Pipelines, Oil Pipelines, Energy and Corporate. 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 2009 through 2011.

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, 2011, the Company reported Goodwill of \$3.7 billion (2010 \$3.6 billion). Goodwill 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 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.

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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 requirement to record an impairment charge. In addition to the above noted estimates and assumptions used by the Company in its fair value determinations, the realization of Ravenswood's fair value is partially dependent on a favourable resolution of the NYISO actions relating to capacity prices as described further in Energy Opportunities and Developments. An unfavourable outcome could have a negative effect on the estimated fair value and may, in future periods, result in an impairment of a portion of the US\$834 million Goodwill balance relating to Ravenswood at December 31, 2011 (2010 US\$834 million).

ACCOUNTING CHANGES

CHANGES IN ACCOUNTING POLICIES FOR 2011

Business Combinations

Effective January 1, 2011, the Company adopted CICA Handbook Section 1582 "Business Combinations", which is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, expensing of acquisition costs, and increased disclosure. Adoption of this standard had no effect on the financial statements as at and for the year ended December 31, 2011.

Consolidated Financial Statements and Non-Controlling Interests

Entities adopting Section 1582 were also required to adopt CICA Handbook Sections 1601 "Consolidated Financial Statements" and 1602 "Non-Controlling Interests". Sections 1601 and 1602 require Non-Controlling Interests to be presented as part of Equity on the balance sheet. In addition, the income statement of the controlling parent now includes 100 per cent of the subsidiary's results and presents the allocation of net income between the controlling and non-controlling interests. Changes resulting from the adoption of Sections 1601 and 1602 were applied retrospectively.

FUTURE ACCOUNTING CHANGES

U.S. GAAP

The CICA's Accounting Standards Board previously announced that Canadian publicly accountable enterprises were required to adopt International Financial Reporting Standards (IFRS) effective January 1, 2011, with the exception of certain qualifying entities historically using RRA that were given a one year deferral from adopting IFRS. TransCanada is a qualifying entity for these purposes and has deferred the adoption of IFRS. The Company has prepared its consolidated financial statements for 2011 in accordance with CGAAP in order to continue using RRA.

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In the application of CGAAP, TransCanada follows specific accounting guidance under U.S. GAAP unique to rate-regulated businesses. These RRA standards allow the timing of recognition of certain revenues and expenses to differ from the timing that may otherwise be expected in a non-rate-regulated business under CGAAP in order to

appropriately reflect the economic impact of regulators' decisions regarding the Company's revenues and tolls. The International Accounting Standards Board has concluded that the development of RRA under IFRS requires further analysis and TransCanada does not expect a final RRA standard under IFRS to be effective in the foreseeable future.

As a registrant with the SEC, TransCanada has the option under Canadian disclosure rules to prepare and file its consolidated financial statements using U.S. GAAP. As a result of the developments noted above, the Company's Board of Directors has approved the adoption of U.S. GAAP effective January 1, 2012. The financial reporting impact of TransCanada adopting U.S. GAAP is disclosed in Note 25 of the Consolidated Financial Statements. The differences between CGAAP and U.S. GAAP are consistent with those reported by the Company in its annual "Reconciliation to United States GAAP" as filed in prior years. Significant changes to existing systems and processes are not required to implement U.S. GAAP as the Company's primary accounting framework.

Fair Value Measurement

In May 2011, the Financial Accounting Standards Board (FASB) issued amended guidance on fair value measurements, which updated some of the existing measurement guidance and included enhanced disclosure requirements under U.S. GAAP. This guidance is effective for interim and annual periods beginning after December 15, 2011. Adoption of these amendments is expected to result in an increase in the qualitative and quantitative disclosures regarding Level 3 measurements, however, the Company expects no material effect on the financial statements.

Intangibles Goodwill and Other

In September 2011, the FASB issued new guidance on testing goodwill for impairment which simplifies an entity's testing for goodwill impairment under U.S. GAAP by permitting an entity to first assess qualitative factors affecting the fair value of a reporting unit in comparison to the carrying amount, as a basis for determining whether it is required to proceed to the two-step quantitative goodwill impairment test. This guidance is effective for interim and annual goodwill impairment tests performed for fiscal years beginning after December 15, 2011. Adoption is not expected to impact the financial statements.

Balance Sheet Offsetting/Netting

In December 2011, the FASB issued amended guidance to enhance disclosures that will enable users of the financial statements to evaluate the effect, or potential effect, of netting arrangements on an entity's financial position. The amendments result in enhanced disclosures by requiring additional information regarding financial instruments and derivative instruments that are either offset in accordance with current U.S. GAAP or subject to an enforceable master netting agreement. This guidance is effective for annual periods beginning on or after January 1, 2013. Adoption of these amendments is expected to result in an increase in disclosures regarding financial instruments which are subject to offsetting as described in this amendment.

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA⁽¹⁾

	2011			
	Fourth	Third	Second	First
<i>(unaudited)</i>				
<i>(millions of dollars except per share amounts)</i>				
Revenues	2,360	2,393	2,143	2,243
Net Income Attributable to Common Shares	375	384	353	415
Share Statistics				
Net income per share – basic and diluted	\$0.53	\$0.55	\$0.50	\$0.59
Dividend declared per common share	\$0.42	\$0.42	\$0.42	\$0.42
2010				
<i>(unaudited)</i>				
<i>(millions of dollars except per share amounts)</i>				
Revenues	2,057	2,129	1,923	1,955
Net Income Attributable to Common Shares	269	377	285	296
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

(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 prices and 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 2011 and 2010 were as follows:

Fourth Quarter 2011 EBIT excluded net unrealized after-tax gains of \$9 million (\$9 million pre-tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

Third Quarter 2011 Energy's EBIT included the positive impact of higher prices for Western Power. EBIT included net unrealized losses of \$47 million pre-tax (\$33 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

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

First Quarter 2011 Natural Gas Pipelines' EBIT included incremental earnings from Bison, which was placed in service in January 2011. Oil Pipelines began recording EBIT for the Wood River/Patoka and Cushing Extension sections of Keystone in February 2011. EBIT included net unrealized losses of \$17 million pre-tax (\$10 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

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

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

Second Quarter 2010 Energy's EBIT included net unrealized gains of \$15 million pre-tax (\$10 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. Net Income reflected a decrease of \$58 million after tax due to losses in 2010 compared to gains in 2009 for interest rate and foreign exchange rate derivatives that did not qualify as hedges for accounting purposes and the translation of U.S. dollar-denominated working capital balances.

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

FOURTH QUARTER 2011 HIGHLIGHTS

Reconciliation of Non-GAAP Measures

	Natural Gas Pipelines		Oil Pipelines		Energy		Corporate		Total	
Three months ended December 31 (<i>unaudited</i>) (<i>millions of dollars</i>)	2011	2010	2011	2010	2011	2010	2011	2010	2011	2010
Comparable EBITDA	739	737	179		295	301	(29)	(33)	1,184	1,005
Depreciation and amortization	(251)	(241)	(35)		(100)	(103)	(4)		(390)	(344)
Comparable EBIT	488	496	144		195	198	(33)	(33)	794	661
Other Income Statement Items										
Comparable interest expense									(251)	(173)
Interest expense of joint ventures									(15)	(15)
Comparable interest income and other									8	61
Comparable income taxes									(123)	(103)
Net income attributable to non-controlling interests									(33)	(33)
Preferred share dividends									(14)	(14)
Comparable Earnings									366	384
Specific items (net of tax):										
Valuation provision for MGP										(127)
Risk management activities ⁽¹⁾									9	12
Net Income Attributable to Common Shares									375	269
Three months ended December 31 (<i>unaudited</i>)(<i>millions of dollars except per share amounts</i>)										
									2011	2010
Comparable Interest Income and Other									8	61
Specific item:										
Risk management activities ⁽¹⁾									35	
Interest Income and Other									43	61
Comparable Income Taxes									(123)	(103)
Specific items:										
Valuation provision for MGP										19
Risk management activities ⁽¹⁾										(10)
Income Taxes Expense									(123)	(94)
Comparable Earnings per Common Share									\$0.52	\$0.55

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Specific items (net of tax):		
Valuation provision for MGP		(0.18)
Risk management activities ⁽¹⁾	0.01	0.02
<hr/>		
Net Income per Common Share	\$0.53	\$0.39
<hr/>		

(1) Three months ended December 31

<i>(unaudited)(millions of dollars)</i>	2011	2010
<hr/>		
Risk Management Activities Gains/(Losses):		
U.S. Power derivatives	(33)	24
Natural Gas Storage proprietary inventory and derivatives	7	(2)
Foreign exchange derivatives	35	
Income taxes attributable to risk management activities		(10)
<hr/>		
Risk Management Activities	9	12
<hr/>		

96 MANAGEMENT'S DISCUSSION AND ANALYSIS

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Comparable Earnings in fourth quarter 2011 were \$366 million or \$0.52 per share compared to \$384 million or \$0.55 per share for the same period in 2010. Comparable Earnings in fourth quarter 2011 excluded net unrealized after-tax gains of \$9 million (\$9 million pre-tax) (2010 \$12 million after-tax gains; \$22 million pre-tax) resulting from changes in the fair value of certain risk management activities. Comparable Earnings in fourth quarter 2010 also excluded the \$127 million after tax (\$146 million pre-tax) valuation provision on advances to the APG for the MGP.

Comparable Earnings decreased \$18 million or \$0.03 per share in fourth quarter 2011 compared to the same period in 2010 and included the following:

decreased Comparable EBIT from Natural Gas Pipelines reflecting lower incentive earnings from the Canadian Mainline and the Alberta System and lower revenues from certain U.S. Pipelines partially offset by incremental earnings from Bison and Guadalajara which were placed in service in January and June 2011, respectively;

Oil Pipelines Comparable EBIT as the Company commenced recording earnings from Keystone in February 2011;

decreased Comparable EBIT from Energy reflecting lower Bruce A and B volumes and higher operating costs as well as lower realized prices at Bruce B, lower contributions from U.S. Power and lower Natural Gas Storage revenues partially offset by higher realized prices in Western Power and incremental earnings from the start-up of Coolidge in May 2011;

increased Comparable Interest Expense primarily due to decreased capitalized interest upon placing Keystone and other new assets in service in 2011;

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

increased Comparable Income Taxes due to higher positive income tax adjustments which reduced income taxes in fourth quarter 2010.

TransCanada's Net Income Attributable to Common Shares was \$375 million or \$0.53 per share in fourth quarter 2011 compared to \$269 million or \$0.39 per share in fourth quarter 2010.

Natural Gas Pipelines' Comparable EBIT was \$488 million in fourth quarter 2011 compared to \$496 million for the same period in 2010. Comparable EBIT in 2010 excluded a \$146 million pre-tax valuation provision on advances to the APG for the MGP.

Canadian Mainline's net income in fourth quarter 2011 decreased \$11 million to \$60 million compared to the same period in 2010. This decrease was primarily due to lower incentive earnings, a lower ROE as determined by the NEB of 8.08 per cent in 2011 compared to 8.52 per cent in 2010, as well as a lower average investment base.

The Alberta System's net income of \$51 million in fourth quarter 2011 decreased \$2 million compared to the same period in 2010. The lower net income was primarily due to lower incentive earnings, partially offset by the positive impact of a higher average investment base.

Canadian Mainline's Comparable EBITDA of \$262 million in fourth quarter 2011 decreased \$7 million compared to the same period in 2010. The Alberta System's Comparable EBITDA was \$185 million in fourth quarter 2011 compared to \$194 million for the same period in 2010. EBITDA from the Canadian Mainline and the Alberta System includes net income variances discussed above as well as flow through items which do not affect net income.

ANR's Comparable EBITDA in fourth quarter 2011 was US\$73 million compared to US\$76 million for the same period in 2010. The decrease in fourth quarter 2011 was primarily due to higher OM&A costs.

GTN's Comparable EBITDA in fourth quarter 2011 from TransCanada's direct investment was US\$26 million compared to US\$45 million for the same period in 2010. The decrease was primarily due to TransCanada's sale of a 25 per cent interest in GTN to TC PipeLines, LP in May 2011 and lower revenues.

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The Bison pipeline was placed in service on January 14, 2011. TransCanada's portion of Comparable EBITDA from its direct investment was US\$14 million in fourth quarter 2011. EBITDA reflects TransCanada's 75 per cent direct interest in Bison subsequent to the sale of a 25 per cent interest in Bison to TC PipeLines, LP in May 2011 and 100 per cent prior to that date.

Comparable EBITDA from the remainder of the U.S. Natural Gas Pipelines was US\$145 million in fourth quarter 2011 compared to US\$128 million for the same period in 2010. The increases were primarily due to incremental earnings from the Guadalajara pipeline, which was placed in service in June 2011. In addition, lower general, administrative and support costs increased EBITDA in fourth quarter 2011, offset by lower earnings from Great Lakes and Portland.

Natural Gas Pipelines' Depreciation and Amortization increased \$10 million in fourth quarter 2011 compared to the same period in 2010 primarily due to the Guadalajara and Bison pipelines being placed in service in 2011.

Natural Gas Pipelines' Business Development Comparable EBITDA losses, resulting from business development expenses, decreased \$6 million in fourth quarter 2011 compared to the same period in 2010 primarily due to decreased business development costs related to the Alaska Pipeline Project. Project applicable expenses and reimbursements are shared proportionately with ExxonMobil, TransCanada's joint venture partner in developing the Alaska Pipeline Project.

Oil Pipelines Comparable EBIT in fourth quarter 2011 was \$144 million. At the beginning of February 2011, the Company commenced recording EBITDA for the Wood River/Patoka section of Keystone following the NEB's decision to remove the MOP restriction along the conversion section of the system and completion of the required operational modifications. The Cushing Extension was also placed in service at that time.

Energy's Comparable EBIT was \$195 million in fourth quarter 2011 compared to \$198 million for the same period in 2010.

Western Power's Comparable EBITDA of \$143 million and Power revenues of \$294 million in fourth quarter 2011 increased \$95 million and \$114 million, respectively, compared to the same period in 2010, primarily due to higher overall realized power prices in Alberta and incremental earnings from Coolidge, which went in service under a 20-year PPA in May 2011. Plant outages and higher demand resulted in average spot market power prices in Alberta increasing 65 per cent to \$76 per MWh in fourth quarter 2011 compared to \$46 per MWh in fourth quarter 2010.

Western Power's Comparable EBITDA in fourth quarter 2011 included \$57 million of accrued earnings from the Sundance A PPA, the revenues and costs of which have been recorded as though the outages of Sundance A Units 1 and 2 were interruptions of supply in accordance with the terms of the PPA.

Eastern Power's Comparable EBITDA of \$87 million and Power Revenues of \$125 million in fourth quarter 2011 increased \$10 million and \$12 million, respectively, compared to the same period in 2010 primarily due to higher Bécancour contractual earnings.

TransCanada's proportionate share of Bruce A's Comparable EBITDA decreased \$34 million to a loss of \$1 million in fourth quarter 2011 compared to EBITDA of \$33 million in fourth quarter 2010. The decrease was primarily due to lower volumes reflecting the November 6, 2011 commencement of the approximate six-month West Shift Plus planned outage as part of the life extension strategy for Unit 3.

TransCanada's proportionate share of Bruce B's Comparable EBITDA decreased \$32 million to \$34 million in fourth quarter 2011 compared to \$66 million in fourth quarter 2010 due to higher operating costs, lower volumes due to increased planned outage days and lower realized prices resulting from the expiry of fixed-price contracts at higher prices.

U.S. Power's Comparable EBITDA in fourth quarter 2011 of US\$32 million decreased US\$27 million compared to the same period in 2010 primarily due to the negative impact of lower commodity and capacity prices and lower physical sales volumes partially offset by new sales activity in PJM.

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Natural Gas Storage's Comparable EBITDA in fourth quarter 2011 was \$23 million compared to \$37 million for the same period in 2010. The decrease of \$14 million in Comparable EBITDA in fourth quarter 2011 was primarily due to decreased proprietary natural gas and third party storage revenues as a result of lower realized natural gas price spreads.

Comparable Interest Expense in fourth quarter 2011 increased \$78 million to \$251 million from \$173 million in fourth quarter 2010. The increase primarily reflected lower capitalized interest upon placing Keystone and other new assets in service in 2011.

Comparable Interest Income and Other in fourth quarter 2011 decreased \$53 million to \$8 million from income of \$61 million in fourth quarter 2010. The decrease in fourth quarter reflected realized losses in 2011 compared to gains in 2010 on derivatives used to manage the Company's net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Comparable Income Taxes were \$123 million in fourth quarter 2011 compared to \$103 million for the same period in 2010. The increase was primarily due to higher positive income tax adjustments that reduced income taxes in fourth quarter 2010 compared to 2011.

SHARE INFORMATION

At February 8, 2012, TransCanada had 704 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 seven million outstanding options to purchase common shares, of which five million were exercisable as at February 8, 2012.

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 2007 to 2011 is found under the heading "Five Year Financial Highlights" in the Supplementary Information section of the Company's Annual Report.

GLOSSARY OF TERMS

AFUDC	Allowance for funds used during construction
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
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, Indiana and Ohio, and regulated underground natural gas storage facilities in Michigan
APG	Aboriginal Pipeline Group
ARO	Asset retirement obligation
ATWACC	After-tax weighted average cost of capital
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
Bison LLC	Bison Pipeline LLC
BPC	BPC Generation Infrastructure Trust
BPRIA	Bruce Power Refurbishment Implementation Agreement
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)
Canadian Mainline	A natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec
Cancarb	A waste-heat fuelled power plant and 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, four plus the first phase of the fifth which are operational and phase two of the fifth under construction
CFE	Comisión Federal de Electricidad
CGAAP	Canadian generally accepted accounting principles as defined in Part V of the Canadian Institute of Chartered Accountants Handbook
CICA	Canadian Institute of Chartered Accountants
CO ₂	Carbon dioxide
Coolidge	A simple-cycle, natural gas-fired peaking power generation station in Coolidge, Arizona
COSO	Committee of Sponsoring Organizations of the Treadway Commission
CrossAlta	An underground natural gas storage facility near Crossfield, Alberta
CSP	Contingent Support Payments
Cushing Extension	A crude oil pipeline extending from Steele City, Nebraska to Cushing, Oklahoma
DB Plans	Defined benefit pension plans
DC Plans	Defined contribution pension plans
DOS	U.S. Department of State
DRP	Dividend Reinvestment and Share Purchase Plan
EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes, depreciation and amortization

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Edson	An underground natural gas storage facility near Edson, Alberta
EPA	Environmental Protection Agency (U.S.)
ExxonMobil	Exxon Mobil Corporation
FASB	Financial Accounting Standards Board
FCM	Forward Capacity Market
FEIS	Final Environmental Impact Statement
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
Fracking	Multi-stage hydraulic fracturing
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.
GTN	A natural gas transmission system extending from the B.C./Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon
GTN LLC	Gas Transmission Northwest LLC
Guadalajara	A natural gas pipeline 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
HOEP	Hourly Ontario energy price
HSE	Health, safety and environment
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	The crude oil pipeline system which extends from Hardisty, Alberta to the U.S. markets and includes the Wood River/Patoka, the Cushing Extension and Keystone XL
Keystone XL	A proposed extension and expansion of the Keystone oil pipeline to the U.S. Gulf Coast, which includes the construction of a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast, the expansion of existing facilities at Hardisty, Alberta and the construction of a new crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska
Kibby Wind	A wind farm located in Kibby and Skinner townships in northwestern Franklin County, Maine
km	Kilometre(s)
LMCI	Land Matters Consultation Initiative
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
NEXT	Natural Gas Liquids Extraction Model
NGTL	NOVA Gas Transmission Ltd.
NID	National Interest Determination

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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	A natural gas-fired, combined-cycle plant in Burrillville, Rhode Island
PHMSA	Pipeline and Hazardous Materials Safety Administration
PJM Interconnection (PJM)	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
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
Restructuring Proposal	Canadian Mainline 2012 Tolls Application and Restructuring Proposal
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
TC Keystone	TransCanada Keystone Pipeline, LP
Tcf	Trillion cubic feet
TCPL	TransCanada PipeLines Limited
TCPL USA	TransCanada PipeLine USA Ltd.
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
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	A crude oil pipeline extending from Hardisty, Alberta to U.S. markets at 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 as defined in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook (CGAAP) 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 2011 to that in 2010, and highlights significant changes between 2010 and 2009. 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 control 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 control 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 (COSO). Management concluded, based on its evaluation, that internal control over financial reporting are effective as of December 31, 2011, 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 controls. 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 CGAAP. 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 13, 2012

TRANSCANADA CORPORATION **103**

**Independent
Auditors'
Report**

To the Shareholders of TransCanada Corporation

We have audited the accompanying consolidated financial statements of TransCanada Corporation, which comprise the consolidated balance sheets as at December 31, 2011 and 2010, the consolidated statements of income, comprehensive income, accumulated other comprehensive income, equity and cash flows for each of the years in the three-year period ended December 31, 2011, 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 judgment, 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 opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of TransCanada Corporation as at

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December 31, 2011 and 2010 and its consolidated results of operations and its consolidated cash flows for each of the years in the three-year period ended December 31, 2011 in accordance with Canadian generally accepted accounting principles.

Chartered Accountants
Calgary, Canada

February 13, 2012

104 CONSOLIDATED FINANCIAL STATEMENTS

TRANSCANADA CORPORATION
CONSOLIDATED INCOME
Year ended December 31
(millions of dollars except per share amounts)

	2011	2010	2009
Revenues	9,139	8,064	8,181
Operating and Other Expenses			
Plant operating costs and other	3,449	3,114	3,213
Commodity purchases resold	941	1,017	831
Depreciation and amortization	1,528	1,354	1,377
Valuation provision for MGP (Note 9)		146	
	5,918	5,631	5,421
Financial Charges/(Income)			
Interest expense (Note 13)	937	701	954
Interest expense of joint ventures (Note 14)	55	59	64
Interest income and other	(55)	(94)	(121)
	937	666	897
Income before Income Taxes	2,284	1,767	1,863
Income Tax Expense/(Recovery) (Note 12)			
Current	209	(141)	30
Future	364	521	357
	573	380	387
Net Income	1,711	1,387	1,476
Net Income Attributable to Non-Controlling Interests (Note 16)	129	115	96
Net Income Attributable to Controlling Interests	1,582	1,272	1,380
Preferred Share Dividends (Note 18)	55	45	6
Net Income Attributable to Common Shares	1,527	1,227	1,374
Net Income per Common Share (Note 17)			
Basic	\$2.18	\$1.78	\$2.11
Diluted	\$2.17	\$1.77	\$2.11

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

TRANSCANADA CORPORATION
CONSOLIDATED COMPREHENSIVE INCOME

Year ended December 31
(millions of dollars)

	2011	2010	2009
Net Income	1,711	1,387	1,476
Other Comprehensive Income/(Loss), Net of Income Taxes			
Change in foreign currency translation gains and losses on investments in foreign operations ⁽¹⁾	113	(180)	(471)
Change in fair value of derivative instruments to hedge the net investments in foreign operations ⁽²⁾	(73)	89	258
Change in fair value of derivative instruments designated as cash flow hedges ⁽³⁾	(203)	(141)	75
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges ⁽⁴⁾	127	(7)	(15)
Other Comprehensive Loss	(36)	(239)	(153)
Comprehensive Income	1,675	1,148	1,323
Comprehensive Income Attributable to Non-Controlling Interests	140	121	103
Comprehensive Income Attributable to Controlling Interests	1,535	1,027	1,220
Preferred Share Dividends	55	45	6
Comprehensive Income Attributable to Common Shares	1,480	982	1,214

(1) Net of income tax recovery of \$29 million in 2011 (2010 \$65 million expense; 2009 \$92 million expense).

(2) Net of income tax recovery of \$28 million in 2011 (2010 \$37 million expense; 2009 \$124 million expense).

(3) Net of income tax recovery of \$104 million in 2011 (2010 \$95 million recovery; 2009 \$7 million expense).

(4) Net of income tax expense of \$77 million in 2011 (2010 \$21 million expense; 2009 \$9 million expense).

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)

	2011	2010	2009
Cash Generated from Operations			
Net income	1,711	1,387	1,476
Depreciation and amortization	1,528	1,354	1,377
Future income taxes (Note 12)	364	521	357
Employee future benefits funding in excess of expense (Note 20)	(3)	(69)	(111)
Valuation provision for MGP (Note 9)		146	
Other	63	(8)	(19)
	3,663	3,331	3,080
Decrease/(increase) in operating working capital (Note 22)	310	(249)	(90)
Net cash provided by operations	3,973	3,082	2,990
Investing Activities			
Capital expenditures (Note 4)	(3,274)	(5,036)	(5,417)
Deferred amounts and other	(14)	(384)	(594)
Acquisitions, net of cash acquired (Note 23)			(902)
Net cash used in investing activities	(3,288)	(5,420)	(6,913)
Financing Activities			
Dividends on common and preferred shares (Notes 17 and 18)	(1,016)	(754)	(728)
Distributions paid to non-controlling interests	(131)	(112)	(100)
Notes payable (repaid)/issued, net	(218)	474	(244)
Long-term debt issued, net of issue costs	1,622	2,371	3,267
Repayment of long-term debt	(1,272)	(494)	(1,005)
Long-term debt of joint ventures issued	48	177	226
Repayment of long-term debt of joint ventures	(102)	(254)	(246)
Common shares issued, net of issue costs	58	26	1,820
Preferred shares issued, net of issue costs		679	539
Partnership units of subsidiary issued, net of issue costs (Note 23)	321		193
Net cash (used in)/provided by financing activities	(690)	2,113	3,722
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents			
	6	(8)	(110)
Increase/(Decrease) in Cash and Cash Equivalents	1	(233)	(311)
Cash and Cash Equivalents			
Beginning of year	764	997	1,308
Cash and Cash Equivalents			
End of year	765	764	997

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)

	2011	2010
ASSETS		
Current Assets		
Cash and cash equivalents	765	764
Accounts receivable	1,265	1,271
Inventories	416	425
Other	1,194	870
	3,640	3,330
Plant, Property and Equipment (Note 5)	38,262	36,244
Goodwill (Note 6)	3,650	3,570
Regulatory Assets (Note 7)	1,405	1,512
Intangibles and Other Assets (Note 9)	2,038	2,138
	48,995	46,794
LIABILITIES		
Current Liabilities		
Notes payable (Note 10)	1,880	2,092
Accounts payable	2,659	2,272
Accrued interest	373	367
Current portion of long-term debt (Note 13)	935	894
Current portion of long-term debt of joint ventures (Note 14)	33	65
	5,880	5,690
Regulatory Liabilities (Note 7)	303	314
Deferred Amounts (Note 11)	805	694
Future Income Taxes (Note 12)	3,788	3,398
Long-Term Debt (Note 13)	17,632	17,028
Long-Term Debt of Joint Ventures (Note 14)	789	801
Junior Subordinated Notes (Note 15)	1,009	985
	30,206	28,910
EQUITY		
Controlling interests	17,324	16,727
Non-controlling interests (Note 16)	1,465	1,157
	18,789	17,884
	48,995	46,794

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

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TRANSCANADA CORPORATION
CONSOLIDATED ACCUMULATED OTHER COMPREHENSIVE (LOSS)/INCOME

<i>(millions of dollars)</i>	Currency Translation Adjustments	Cash Flow Hedges and Other	Total
Balance at January 1, 2009	(379)	(93)	(472)
Change in foreign currency translation gains and losses on investments in foreign operations ⁽¹⁾	(471)		(471)
Change in fair value of derivative instruments to hedge the net investments in foreign operations ⁽²⁾	258		258
Change in fair value of 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 ⁽⁴⁾		(24)	(24)
Balance at December 31, 2009	(592)	(40)	(632)
Change in foreign currency translation gains and losses on investments in foreign operations ⁽¹⁾	(180)		(180)
Change in fair value of derivative instruments to hedge the net investments in foreign operations ⁽²⁾	89		89
Change in fair value of 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 ⁽⁴⁾		(17)	(17)
Balance at December 31, 2010	(683)	(194)	(877)
Change in foreign currency translation gains and losses on investments in foreign operations⁽¹⁾	113		