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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, 2014** Commission File Number **1-31690**

TRANSCANADA CORPORATION

(Exact Name of Registrant as specified in its charter)

Canada
(Province or other 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., 700 Louisiana Street, Suite 700
Houston, Texas, 77002-2700; (832) 320-5201
(Name, address (including zip code) and telephone number (including area code)
of agent for service in the United States)

Securities registered or to be 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 or to be 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**

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

ý Annual information form ý 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, 2014, 708,662,996 common shares;
9,498,423 Cumulative Redeemable First Preferred Shares, Series 1;
12,501,577 Cumulative Redeemable First Preferred Shares, Series 2;
14,000,000 Cumulative Redeemable First Preferred Shares, Series 3;
14,000,000 Cumulative Redeemable First Preferred Shares, Series 5;
24,000,000 Cumulative Redeemable First Preferred Shares, Series 7; and
18,000,000 Cumulative Redeemable First Preferred Shares, Series 9
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 ý No o

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 ý No o

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	333-184074
S-8	333-151736
F-3	33-13564
F-3	333-6132
F-10	333-151781
F-10	333-161929
F-10	333-192561

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

Except sections specifically referenced below which shall be deemed incorporated by reference herein and filed, no other portion of the TransCanada Corporation 2014 Annual report to shareholders 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 121 through 182 of the TransCanada Corporation 2014 Annual report to shareholders included herein.

B. Management's Discussion and Analysis

For management's discussion and analysis, see pages 21 through 120 of the TransCanada Corporation 2014 Annual report to shareholders included herein under the heading "Management's discussion and analysis".

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

For management's report on internal control over financial reporting, see "Management's report on Internal Control over Financial Reporting" that accompanies the audited consolidated financial statements on page 121 of the TransCanada Corporation 2014 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 "Other information — Controls and Procedures" in Management's discussion and analysis on pages 105 and 106 of the TransCanada Corporation 2014 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 and Mr. Siim A. Vanaselja have been designated audit committee financial experts and are 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 and Mr. Vanaselja as audit committee financial experts does not make Mr. Benson or Mr. Vanaselja "experts" for any purpose, impose any duties, obligations or liability on Mr. Benson or Mr. Vanaselja 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 a code of business ethics for its directors, officers, employees and contractors. The Registrant's code is available on its website at www.transcanada.com. No waivers have been granted from any provision of the code during the 2014 fiscal year.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

For information on principal accountant fees and services, see "Audit committee — Pre-approval Policies and Procedures" and "Audit committee — External Auditor Service Fees" on pages 36 and 37 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 26 of the Notes to the 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 page 95 of the TransCanada Corporation 2014 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
	M.P. Salomone
	D.M.G. Stewart
	S.A. Vanaselja

FORWARD-LOOKING INFORMATION

We disclose forward-looking information to help current and potential investors understand management's assessment of our future plans and financial outlook, and our future prospects overall.

Statements that are *forward-looking* are based on certain assumptions and on what we know and expect today and generally include words like *anticipate, expect, believe, may, will, should, estimate* or other similar words.

Forward-looking statements in this document may include information about the following, among other things:

- anticipated business prospects
- our financial and operational performance, including the performance of our subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows and future financing options available to us
- expected costs for planned projects, including projects under construction and in development
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes
- expected impact of regulatory outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future accounting changes, commitments and contingent liabilities
- expected industry, market and economic conditions.

Forward-looking statements do not guarantee future performance. Actual events and results could be significantly different because of assumptions, risks or uncertainties related to our business or events that happen after the date of this document.

Our forward-looking information is based on the following key assumptions, and subject to the following risks and uncertainties:

Assumptions

- inflation rates, commodity prices and capacity prices
- timing of financings and hedging
- regulatory decisions and outcomes
- foreign exchange rates
- interest rates

- tax rates
- planned and unplanned outages and the use of our pipeline and energy assets
- integrity and reliability of our assets
- access to capital markets
- anticipated construction costs, schedules and completion dates
- acquisitions and divestitures.

Risks and uncertainties

- our ability to successfully implement our strategic initiatives
- whether our strategic initiatives will yield the expected benefits
- the operating performance of our pipeline and energy assets
- amount of capacity sold and rates achieved in our pipelines business
- the availability and price of energy commodities
- the amount of capacity payments and revenues we receive from our energy business
- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration and insurance claims
- performance of our counterparties
- changes in market commodity prices
- changes in the political environment
- changes in environmental and other laws and regulations
- competitive factors in the pipeline and energy sectors
- construction and completion of capital projects
- costs for labour, equipment and materials
- access to capital markets
- interest and foreign exchange rates
- weather
- cyber security
- technological developments
- economic conditions in North America as well as globally.

You can read more about these factors and others in reports we have filed with Canadian securities regulators and the U.S. Securities and Exchange Commission (SEC).

As actual results could vary significantly from the forward-looking information, you should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events, unless we are required to 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 13, 2015

DOCUMENTS FILED AS PART OF THIS REPORT

13.1	TransCanada Corporation Annual information form for the year ended December 31, 2014.
13.2	Management's discussion and analysis (included on pages 21 through 120 of the TransCanada Corporation 2014 Annual report to shareholders).
13.3	2014 Audited consolidated financial statements (included on pages 121 through 182 of the TransCanada Corporation 2014 Annual report to shareholders), including the auditors' report thereon and the Report of Independent Registered Public Accounting Firm on the effectiveness of TransCanada's internal control over financial reporting as of December 31, 2014.

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.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

TransCanada Corporation

2014 Annual information form

February 12, 2015



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Presentation of information

Throughout this Annual information form (**AIF**), the terms, *we*, *us*, *our*, *the Company* and *TransCanada* mean TransCanada Corporation and its subsidiaries. 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 (**Arrangement**) with TCPL, which is described in the *TransCanada Corporation – Corporate structure* section below, such 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, 2014 (**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. The *Glossary* found at the end of this AIF contains certain terms defined throughout this AIF and abbreviations and acronyms that may not otherwise be defined in this document.

Certain portions of TransCanada's Management's discussion and analysis dated February 12, 2015 (**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.

Financial information is presented in accordance with United States generally accepted accounting principles (**GAAP**). We use certain financial measures that do not have a standardized meaning under GAAP and therefore they may not be comparable to similar measures presented by other entities. Refer to the *About this document – Non-GAAP measures* section of the MD&A for more information about the non-GAAP measures we use and a reconciliation to their GAAP equivalents, which section of the MD&A is incorporated by reference herein.

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. We disclose forward-looking information to help current and potential investors understand management's assessment of our future plans and financial outlook, and our future prospects overall.

Statements that are *forward-looking* are based on certain assumptions and on what we know and expect today and generally include words like *anticipate*, *expect*, *believe*, *may*, *will*, *should*, *estimate* or other similar words.

Forward-looking statements contained or incorporated by reference in this AIF may include information about the following, among other things:

- anticipated business prospects
- our financial and operational performance, including the performance of our subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows and future financing options available to us
- expected costs for planned projects, including projects under construction and in development
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes
- expected impact of regulatory outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future accounting changes, commitments and contingent liabilities
- expected industry, market and economic conditions.

Forward-looking statements do not guarantee future performance. Actual events and results could be significantly different because of assumptions, risks or uncertainties related to our business or events that happen after the date of this AIF and other disclosure incorporated by reference herein.

Our forward-looking information is based on the following key assumptions, and subject to the following risks and uncertainties:

Assumptions

- inflation rates, commodity prices and capacity prices
- timing of financings and hedging
- regulatory decisions and outcomes
- foreign exchange rates

- interest rates
- tax rates
- planned and unplanned outages and the use of our pipeline and energy assets
- integrity and reliability of our assets
- access to capital markets
- anticipated construction costs, schedules and completion dates
- acquisitions and divestitures.

Risks and uncertainties

- our ability to successfully implement our strategic initiatives
- whether our strategic initiatives will yield the expected benefits
- the operating performance of our pipeline and energy assets
- amount of capacity sold and rates achieved in our pipelines business
- the availability and price of energy commodities
- the amount of capacity payments and revenues we receive from our energy business
- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration and insurance claims
- performance of our counterparties
- changes in market commodity prices
- changes in the political environment
- changes in environmental and other laws and regulations
- competitive factors in the pipeline and energy sectors
- construction and completion of capital projects
- costs for labour, equipment and materials
- access to capital markets
- interest and foreign exchange rates
- weather
- cyber security
- technological developments
- economic conditions in North America as well as globally.

You can read more about these factors and others in reports we have filed with Canadian securities regulators and the U.S. Securities and Exchange Commission (**SEC**).

As actual results could vary significantly from the forward-looking information, you should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events, unless we are required to by law.

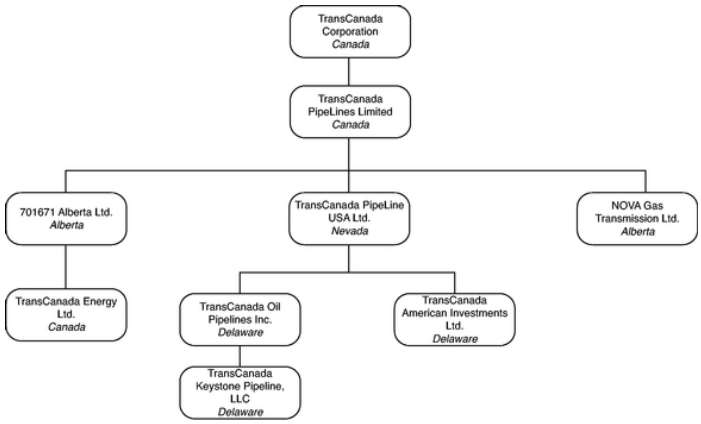
TransCanada Corporation

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 the 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 TransCanada. 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.



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 of TransCanada as at Year End or total consolidated revenues of TransCanada for the year then ended.

General development of the business

We operate our business in three segments: *Natural Gas Pipelines*, *Liquids Pipelines* and *Energy.* Natural Gas Pipelines and Liquids Pipelines are principally comprised of our respective natural gas and liquids pipelines in Canada, the U.S. and Mexico as well as our regulated natural gas storage operations in the U.S. Energy includes our power operations and the non-regulated natural gas storage business in Canada.

Summarized below are significant developments that have occurred in our Natural Gas Pipelines, Liquids Pipelines and Energy businesses, respectively, and certain acquisitions, dispositions, events or conditions which have had an influence on that development, during the last three financial years and year to date in 2015.

DEVELOPMENTS IN THE NATURAL GAS PIPELINES BUSINESS

Canadian Regulated Pipelines

Date	Description of development
NGTL System	
May 2012	The Horn River project was completed, extending the NGTL System into the Horn River shale play in British Columbia (**B.C.**). The total contracted volumes for Horn River, including the extension, are expected to be approximately 900 million cubic feet per day (**MMcf/d**) by 2020.
June 2012	The National Energy Board (**NEB**) approved the Leismer-Kettle River Crossover project, a 77 km (46 miles) pipeline to expand the NGTL System with the intent of increasing capacity to meet demand in northeastern Alberta.
January 2013	The NEB issued its recommendation to the Governor-in-Council that the proposed Chinchaga Expansion component of the Komie North project be approved, but denied the proposed Komie North Extension component.
April 2013	The Leismer-Kettle River Crossover project was placed into service. The cost of the expansion was $150 million.
March 2014	We received an NEB Safety Order (the **Order**) in response to the recent pipeline releases on the NGTL System. The Order required us to reduce the maximum operating pressure on three per cent of NGTL's pipeline segments. We filed a request for a review and variance of the Order that would minimize gas disruptions while still maintaining a high level of safety.
March 2014	The NEB approved approximately $400 million in NGTL facility expansions that were in various stages of development or construction.
April 2014	The NEB granted the review and variance request with certain conditions. We are accelerating components of our integrity management program to address the NEB Order.
Fourth Quarter 2014	We continue to experience significant growth on the NGTL System as a result of growing natural gas supply in northwestern Alberta and northeastern B.C. from unconventional gas plays and substantive growth in intra-basin delivery markets. This demand growth is driven primarily by oil sands development, gas-fired electric power generation and expectations of B.C. west coast LNG projects. This demand for NGTL System services is expected to result in approximately 4.0 billion cubic feet per day (Bcf/d) of incremental firm services with approximately 3.1 Bcf/d related to firm receipt services and 0.9 Bcf/d related to firm delivery services. We will be seeking regulatory approvals in 2015 to construct new facilities to meet these service requests of approximately 540 km (336 miles) of pipeline, seven compressor stations, and 40 meter stations that will be required in 2016 and 2017 (**2016/17 Facilities**). The estimated total capital cost for the facilities is approximately $2.7 billion. Including the new 2016/17 Facilities, the North Montney Mainline, the Merrick Mainline, and other new supply and demand facilities, the NGTL System has approximately $6.7 billion of commercially secured projects in various stages of development.
North Montney Mainline	
August 2013	We signed agreements for approximately two Bcf/d of firm gas transportation services to underpin the development of a major pipeline extension and expansion of the NGTL System to receive and transport natural gas from the North Montney area of B.C. The proposed North Montney Pipeline will include an interconnection with our proposed PRGT (as defined below) project to provide natural gas supply to the proposed Pacific NorthWest liquefied natural gas (**LNG**) export facility near Prince Rupert, B.C. and is expected to cost approximately $1.7 billion, which includes $100 million for downstream facilities. Under commercial arrangements, receipt volumes are expected to increase between 2016 and 2019 to an aggregate volume of approximately two Bcf/d and delivery volumes to the PRGT project are expected to be approximately 2.1 Bcf/d beginning in 2019. We also entered into arrangements with other parties for transportation services that will utilize the North Montney project facilities.
November 2013	We filed an application with the NEB to construct and operate the North Montney Pipeline.
February 2014	The NEB issued a Hearing Order for the North Montney Pipeline. The proposed project consists of approximately 300 km (186 miles) of pipeline and is expected to be placed in service in two sections, Aitken Creek in second quarter 2016 and Kahta in second quarter 2017.
December 2014	The hearing for the application before the NEB to build and operate this project concluded. We expect the NEB to issue its report and recommendations for the project by the end of April 2015.
Merrick Mainline	
June 2014	We announced the signing of agreements for approximately 1.9 Bcf/d of firm natural gas transportation services to underpin the development of a major extension of our NGTL System. The proposed Merrick Mainline will transport natural gas sourced through the NGTL System to the inlet of the proposed Pacific Trail Pipeline that will terminate at the Kitimat LNG Terminal at Bish Cove near Kitimat, B.C. The proposed project will be an extension from the existing Groundbirch Mainline section of the NGTL System beginning near Dawson Creek, B.C. to its end point near the community of Summit Lake, B.C. The $1.9 billion project will consist of approximately 260 km (161miles) of 48-inch diameter pipe. Subject to the necessary approvals, which includes the regulatory approval from the NEB for us to build and operate the pipeline, and a positive final investment decision (**FID**) for the Kitimat LNG project, we expect the Merrick Mainline to be in service in first quarter 2020.
Revenue Requirement Settlements	
December 2012	The current settlements for the NGTL System expired. Final tolls for 2013 were to be determined through either new settlements or rate cases and any orders resulting from the NEB's decision on the Canadian Restructuring Proposal.

Date	Description of development
August 2013	We reached settlement of the NGTL System annual revenue requirement for the years 2013 and 2014 with shippers and other interested parties (the **NGTL 2013 – 2014 Settlement**). The settlement fixed the return on equity (**ROE**) at 10.10 per cent on a 40 per cent deemed common equity, established an increase in the composite depreciation rate to 3.05 per cent and 3.12 per cent for 2013 and 2014, respectively, and fixed the operating, maintenance and administrative (**OM&A**) costs for 2013 at $190 million and 2014 at $198 million with any variance to our account. We also requested and received approval for changes to existing interim rates to reflect the settlement, effective September 1, 2013, pending a decision on the settlement application.
November 2013	The NEB approved the NGTL 2013 – 2014 Settlement and final 2013 rates, as filed, in November 2013.
October 2014	We reached a revenue requirement settlement with our shippers for 2015 on the NGTL System. The terms of the one year settlement included no changes to the ROE of 10.10 per cent on 40 per cent deemed equity, a continuation of the 2014 depreciation rates and a mechanism for sharing variances above and below a fixed OM&A expense amount. The settlement was filed with the NEB in October 2014.
February 2015	We received NEB approval for our revenue requirement settlement with our shippers for 2015 on the NGTL System. The terms of the one year settlement include continuation of the 2014 ROE of 10.10 per cent on 40 per cent deemed equity, continuation of the 2014 depreciation rates and a mechanism for sharing variances above and below a fixed OM&A expense amount that is based on an escalation of 2014 actual costs.
Canadian Mainline	
May 2012	We received NEB approval to build new pipeline facilities to provide Ontario and Québec markets with additional gas supplies from the Marcellus shale basin.
May 2012	The additional open season for firm transportation service on the Canadian Mainline, to bring additional Marcellus shale gas into Canada, closed. We were able to accommodate an additional 50 MMcf/d from the Niagara meter station to Kirkwall, Ontario, effective November 2012.
November 2012	Transportation of natural gas supply from the Marcellus shale basin supply began moving on the Canadian Mainline.
January 2014	Shippers on the Canadian Mainline elected to renew approximately 2.5 Bcf/d of their contracts through November 2016.
Tolls and Tariff Applications and LDC Settlement	
March 2013	We received the NEB decision on our Canadian Restructuring Proposal application to change the business structure and the terms and conditions of service for the Canadian Mainline. The NEB decision established a Toll Stabilization Account (**TSA**) to capture the surplus or the shortfall between our revenues and our cost of service for each year over the five-year term of the decision. The NEB decision also identified certain circumstances that would require a new tolls application prior to the end of the five-year term. One of those circumstances is if the TSA balance becomes positive, which occurred in 2013.
May 2013	We filed a compliance filing and an application for a review and variance of the NEB decision regarding the Canadian Restructuring Proposal.
June 2013	The NEB dismissed the review and variance application and set out a process to consider the tariff revisions. Additional changes to the Canadian Mainline's tariff were considered by the NEB as a separate application which was heard in an oral hearing.
July 2013	The NEB released its reasons for the dismissal. We began implementation of the NEB decision related to the Canadian Restructuring Proposal. Since implementation, an additional 1.3 Bcf/d of firm service originating at Empress, Alberta has been contracted for, more than doubling the contracted capacity of this location. The implementation of the NEB decision was a key priority in 2013 and with the ability to price discretionary services at market prices we were able to essentially meet our overall cost of service requirements for 2013.
September 2013	The Canadian Mainline and the three largest Canadian local distribution companies entered into a settlement (**LDC Settlement**) which was filed with the NEB for approval in December 2013. The LDC Settlement proposed to establish new fixed tolls for 2015 to 2020 and maintain tolls for 2014 at the current rates. The LDC Settlement calculated tolls for 2015 on a base ROE of 10.10 per cent on 40 per cent deemed common equity. It also included an incentive mechanism that requires a $20 million (after tax) annual contribution by us from 2015 to 2020, which could result in a range of ROE outcomes from 8.70 per cent to 11.50 per cent. The LDC Settlement would have enabled the addition of facilities in the Eastern Triangle to serve immediate market demand for supply diversity and market access. The LDC Settlement was intended to provide a market driven, stable, long-term accommodation of future demand in this region in combination with the anticipated lower demand for transportation on the Prairies Line and the Northern Ontario Line while providing a reasonable opportunity to recover our costs. The LDC Settlement also retained pricing flexibility for discretionary services and implemented certain tariff changes and new services as required by the terms of the settlement.

Date	Description of development
March 2014	The NEB responded to the LDC Settlement application we filed in December 2013. The NEB did not approve the application as a settlement but allowed us the option to continue with the application as a contested tolls application, amend the application or terminate the processing of the application. We amended the application with additional information.
May 2014	The NEB released a Hearing Order that set out a hearing process and schedule for the 2015 – 2030 Mainline Tolls and Tariff Application that incorporates the LDC Settlement. The hearing concluded in September 2014.
November 2014	The NEB approved the Canadian Mainline's 2015 – 2030 Tolls and Tariff Application. The application reflected components of the LDC Settlement. The approval of this application provides a long-term commercial platform for both the Canadian Mainline and its shippers with a known toll design for 2015 to 2020 and certain parameters for a toll-setting methodology up to 2030. The platform balances the needs of our shippers while at the same time ensuring a reasonable opportunity to recover the capital from our existing facilities and any new facilities required to serve existing and new markets. Highlights of the approved application include our commitment to add increased pipeline capacity that allows eastern Canadian markets more access to Dawn and Niagara area supplies; renewal provisions that will give us the tools to gain more certainty over capacity requirements; fixed price tolls on one-year and longer firm transportation service; continued pricing discretion for shorter term and interruptible service; a known revenue requirement along with an incentive sharing mechanism that targets a return of 10.10 per cent on a deemed common equity of 40 per cent, with a possible range of outcomes from 8.70 per cent to 11.50 per cent; and the continued use of a deferral account that compensates for the differences between actual revenues and the fixed toll arrangement, plus an agreement that any overall variance in revenues for the 2015-2020 period is assigned to the eastern area shippers for the period beyond 2020.
Eastern Mainline Project	
May 2014	We filed a project description with the NEB for the Eastern Mainline Project.
October 2014	We filed an application seeking NEB approval to build, own and operate new facilities for our existing Canadian Mainline natural gas transmission system in southeastern Ontario (**Eastern Mainline Project**). The new facilities are a result of the proposed transfer of a portion of the Canadian Mainline capacity from natural gas service to crude oil service as part of our Energy East Pipeline and an open season that closed in January 2014. The $1.5 billion capital project will add 0.6 Bcf/d of new capacity in the Eastern Triangle segment of the Canadian Mainline and will ensure appropriate levels of capacity are available to meet the requirements of existing shippers as well as new firm service commitments. The project is contingent upon the Energy East Pipeline and is subject to regulatory approvals expected to be issued simultaneously with regulatory approvals for the Energy East Pipeline. The project is expected to be in service by second quarter 2017.
Other Canadian Mainline Expansions	
November 2014	In addition to the Eastern Mainline Project, we have executed new short haul arrangements in the Eastern Triangle portion of the Canadian Mainline that require new facilities, or modifications to existing facilities with a total capital cost estimate of $475 million with expected in-service dates between November 2015 and November 2016. These projects are subject to regulatory approval and, once constructed, will provide capacity needed to meet customer requirements in eastern Canada.
U.S. Pipelines	
Bison Pipeline	
July 2013	We sold an additional 45 per cent interest in each of Gas Transmission Northwest LLC (**GTN**) and Bison Pipeline LLC (**Bison**) to TC PipeLines, LP (**TCLP**) for an aggregate purchase price of US$1.05 billion. We continued to hold a 30 per cent direct ownership interest in both pipelines.
October 2014	We closed the sale of our remaining 30 per cent interest in Bison to TCLP for cash proceeds of US$215 million.
GTN Pipeline	
July 2013	We sold an additional 45 per cent interest in each of GTN and Bison to TCLP for an aggregate purchase price of US$1.05 billion. We continue to hold a 30 per cent direct ownership interest in both pipelines.
November 2014	We announced an offer to sell the remaining 30 per cent interest in GTN to TCLP. Subject to the satisfactory negotiation of terms and TCLP's board approval, the transaction is expected to close in late first quarter 2015. We continue to hold a 28.3 per cent interest in TCLP for which we are the General Partner.
ANR Pipeline	
June 2012	The FERC issued orders approving ANR's sale of its offshore assets to a newly created wholly owned subsidiary, TC Offshore LLC (**TCO**), allowing TCO to operate these assets as a stand alone interstate pipeline.
August 2012	The FERC approved ANR Storage Company's settlement with its shippers.
November 2012	TCO began commercial operations.
October 2013	We concluded a successful binding open season. We have executed firm transportation contracts for 350 MMcf/d at maximum tariff rates for 10 years on the ANR Lebanon Lateral Reversal project, which will entail modifications to existing facilities. The project substantially increases our ability to receive gas on ANR's Southeast Main Line (**SEML**) from the Utica/Marcellus shale areas.

Date	Description of development
March 2014	We have secured nearly 2.0 Bcf/d of firm natural gas transportation commitments for existing and expanded capacity on ANR Pipeline's SEML. The capacity sales and expansion projects include reversing the Lebanon Lateral in western Ohio, additional compression at Sulphur Springs, Indiana, expanding the Rockies Express pipeline interconnect near Shelbyville, Indiana and 600 MMcf/d of capacity as part of a reversal project on the SEML. Capital costs associated with the ANR System expansions required to bring the additional capacity to market are currently estimated to be US$150 million. The capacity was subscribed at maximum rates for an average term of 23 years with approximately 1.25 Bcf/d of new contracts beginning service in late 2014. These secured contracts on the SEML will move Utica and Marcellus shale gas to points north and south on the system. ANR is also assessing further demand from our customers to transport natural gas from the Utica/Marcellus formation, which is expected to result in incremental opportunities to enhance and expand the system.
Greak Lakes	
November 2013	Great Lakes received Federal Energy Regulatory Commission (**FERC**) approval for a rate settlement with its shippers resulting in maximum recourse rates increasing by approximately 21 per cent resulting in a modest increase in revenues derived from its recourse rate contracts. The settlement includes a 17 month moratorium through March 2015 and requires us to have new rates in effect by January 1, 2018.
Northern Border	
January 2013	Northern Border secured a final settlement agreement with its shippers that the FERC approved in December 2012, effective January 2013. The settlement rates for long haul transportation are approximately 11 per cent lower than 2012 rates and depreciation was lowered from 2.4 to 2.2 per cent. The settlement also includes a three year moratorium on filing cases or challenging the settlement rates but Northern Border must initiate another rate proceeding within five years.
Mexican Pipelines	
Tamazunchale Pipeline Extension Project	
February 2012	We signed a contract with the Comisión Federal de Electricidad (Mexico) (**CFE**) for the Tamazunchale Pipeline Extension project. Engineering, procurement and construction contracts were signed and construction related activities began.
November 2014	Construction of the US$600 million extension was completed. Delays from the original service commencement date in March 2014 were attributed primarily to archeological findings along the pipeline route. Under the terms of the transportation service agreement, these delays were recognized as a force majeure with provisions allowing for collection of revenue from the original service commencement date.
Topolobampo and Mazatlan Pipeline Projects	
November 2012	The CFE awarded us with the contract to build, own and operate the Topolobampo pipeline project. The Topolobampo project is a 530 km (329 miles), 30-inch pipeline with a capacity of 670 MMcf/d and an estimated cost of US$1 billion that will deliver gas to Topolobampo, Sinaloa from interconnects with third party pipelines in El Oro, Sinaloa and El Encino, Chihuahua in Mexico.
November 2012	The CFE awarded us with the contract to build, own and operate the Mazatlan pipeline project from El Oro to Mazatlan, Mexico. The Mazatlan project is a 413 km (257 miles), 24-inch pipeline running from El Oro to Mazatlan, within the state of Sinaloa with a capacity of 200 MMcf/d and an estimated cost of US$400 million.
Fourth Quarter 2014	Permitting, engineering, and construction activities are advancing as planned for these two northwest Mexico pipelines. Both projects are supported by 25-year contracts with the CFE and are expected to be in service mid to late 2016.
Guadalajara	
First Quarter 2013	The compressor station went into service.
International Gas Pipelines	
Gas-Pacifico/INNERGY sale	
November 2014	We closed the sale of our 30 per cent equity interests in Gas Pacifico/INNERGY at a price of $9 million. This sale marks our exit from the Southern Cone region of South America.
LNG Pipeline Projects	
Coastal GasLink	
June 2012	We were selected to design, build, own and operate the proposed Coastal GasLink. The 670 km (416 miles) pipeline is expected to have an initial capacity of 1.7 Bcf/d and will transport natural gas from the Montney gas producing region near Dawson Creek, B.C. to LNG Canada's proposed LNG export facility near Kitimat, B.C.
January 2014	We filed the Environmental Assessment Certificate (**EAC**) application with the B.C. Environmental Assessment Office (**EAO**). We focused on community, landowner, government and Aboriginal engagement as the project advances through the regulatory process. The pipeline would be placed in service near the end of the decade, subject to a FID to be made by LNG Canada after obtaining final regulatory approvals. We continue to advance this project and all costs would be recoverable should the project not proceed.

Date	Description of development
March 2014	The 180-day EAO public review period began and included a 45-day public comment period. The B.C. Oil and Gas Commission (**OGC**) application was filed, together with an addendum to the B.C. Environmental Assessment application to capture recent route refinements. We began updating field work along the pipeline route to support the regulatory applications and refine the capital cost estimates in the second quarter.
October 2014	The EAO issued an EAC for Coastal GasLink. In 2014, we also submitted applications to the OGC for the permits required under the *Oil and Gas Activities Act* to build and operate Coastal GasLink. Regulatory review of those applications is progressing on schedule, with permit decisions anticipated in first quarter 2015. We are currently continuing our engagement with Aboriginal groups and stakeholders along the pipeline route and are progressing detailed engineering and construction planning work to support the regulatory applications and refine the capital cost estimates. Pending the receipt of all required regulatory approvals and a positive FID from our customer, construction is anticipated in 2016, with an in-service date by the end of the decade. Should the project not proceed, our project costs (including AFUDC) are fully recoverable.
Prince Rupert Gas Transmission (PRGT)	
January 2013	We were selected to design, build, own and operate the proposed 750 km (466 miles) PRGT. The proposed pipeline will transport natural gas primarily from the North Montney gas producing region near Fort St John, B.C. to the proposed Pacific Northwest LNG export facility near Prince Rupert, B.C. We were focused on Aboriginal, community, landowner and government engagement as the PRGT advances through the regulatory process with the EAO. We continued to refine our study corridor based on consultation and detailed studies to date.
April 2014	The EAC application was submitted to the EAO for a completeness review and the application was filed with the OGC. The EAC application was subsequently deemed complete by the EAO. The EAO initiated a 180-day review period which included a 45-day public comment period that was completed in July 2014.
November 2014	We received an EAC from the EAO. We have submitted our pipeline permit applications to the OGC for construction of the pipeline and anticipate receiving these permits in first quarter 2015. We have made significant changes to the project route since first announced, increasing it by 150 km (93 miles) to 900 km (559 miles), taking into account Aboriginal and stakeholder input. We continue to work closely with Aboriginal groups and stakeholders along the proposed route to create and deliver appropriate benefits to all impacted groups. We concluded a benefits agreement with the Nisga' a First Nation to allow 85 km (52 miles) of the proposed natural gas pipeline to run through Nisga'a Lands.
December 2014	Our customer announced the deferral of an FID. We continue to work with our contractors to refine capital cost estimates for the project. Once the permitting process with the OGC is complete, and Pacific NorthWest LNG secures the necessary regulatory approvals and proceeds with a positive FID, we will be in a position to begin construction. All costs would be fully recoverable should the project not proceed. The deferral of an FID past the end of 2014 has resulted in a deferral of the expected in-service date for the pipeline. The in-service date will depend on when our customer receives the necessary regulatory approvals and is in a position to make an FID.
Alaska	
March 2012	Three major North Slope producers (the **ANS Producers**), along with us through participation in the Alaska LNG Project, announced agreement on a work plan aimed at commercializing North Slope natural gas resources through an LNG option.
May 2012	We received approval from the State of Alaska to suspend and preserve our activities on the Alaska/Alberta route and focus on the LNG alternative. This allowed us to defer our obligation to file for a U.S. FERC certificate for the Alberta route beyond fall 2012, our original deadline.
July 2012	The Alaska LNG Project announced a non-binding public solicitation of interest in securing capacity on a potential new pipeline system to transport Alaska's North Slope gas. The solicitation of interest took place between August 2012 and September 2012. There were a number of non-binding expressions of interest from potential shippers from a broad range of industry sectors in North America and Asia.
April 2014	The State of Alaska passed new legislation to provide a framework for us, the ANS Producers, and the Alaska Gasline Development Corp. (**AGDC**) to advance the development of an LNG export project.
June 2014	We executed an agreement with the State of Alaska to abandon the previous Alaska to Alberta project governance and framework and executed a new precedent agreement where we will act as the transporter of the State's portion of natural gas under a long-term shipping contract in the Alaska LNG Project. We also entered into a Joint Venture Agreement with the three major ANS Producers and AGDC to commence the pre-front end engineering and design (**pre-FEED**) phase of Alaska LNG Project. The pre-FEED work is anticipated to take two years to complete with our share of the cost to be approximately US$100 million. The precedent agreement also provides us with full recovery of development costs in the event the project does not proceed.
July 2014	The ANS Producers filed an export permit application with the U.S. Department of Energy for the right to export 20 million tonnes per annum of liquefied natural gas for 30 years.
September 2014	The FERC approved the National Environmental Policy Act (**NEPA**) pre-file request jointly made by us, the three major ANS Producers and AGDC. This approval triggers the NEPA environmental review process, which includes a series of community consultations.

Further information about developments in the Natural Gas Pipelines business can be found in the MD&A in the *About our business – Our strategy, Natural Gas Pipelines – Results, Natural Gas Pipelines – Outlook, Natural Gas Pipelines – Understanding the Natural Gas Pipelines Business* and *Natural Gas Pipelines – Significant Events* sections, which sections of the MD&A are incorporated by reference herein.

DEVELOPMENTS IN THE LIQUIDS PIPELINES BUSINESS

Date	Description of development
Keystone Pipeline System	
February 2012	We announced that what had previously been the Cushing to U.S. Gulf Coast section of the Keystone Pipeline System has its own independent value to the marketplace, and that we plan to build it as a stand alone pipeline which is not part of the Keystone XL Presidential Permit application.
May 2012	We filed revised fixed tolls for the second section of the Keystone Pipeline System extending from Steele City, Nebraska to Cushing, Oklahoma, with both the NEB and the FERC. The revised tolls, which reflect the final project costs of the Keystone Pipeline System, became effective in July 2012.
January 2014	We finished constructing the 780 km (485 miles) 36-inch pipeline of the Gulf Coast extension of the Keystone Pipeline System from Cushing, Oklahoma to the U.S. Gulf Coast, and crude oil transportation service on the project began. We projected an average pipeline capacity of 520,000 Bbl/d for the first year of operation. The completion of the Gulf Coast extension in January 2014 expanded the Keystone Pipeline System to a 4,247 km (2,639 miles) pipeline system that transports crude oil from Hardisty, Alberta, to markets in the U.S. Midwest and the U.S. Gulf Coast. To date, the Keystone Pipeline System has delivered more than 830 million barrels of crude oil from Canada to the U.S.
Cushing Marketlink	
October 2012	We commenced construction on the Cushing Marketlink facilities which will facilitate the transportation of crude oil from the market hub at Cushing to the U.S. Gulf Coast refining market on facilities that form part of the Keystone Pipeline System.
September 2014	Construction was completed.
Houston Lateral and Terminal	
Fourth Quarter 2014	Construction continues on the 77 km (48 miles) Houston Lateral pipeline and tank terminal which will extend the Keystone Pipeline System to Houston, Texas refineries. The terminal is expected to have initial storage capacity for 700,000 barrels of crude oil. The pipeline and terminal are expected to be completed in the second half of 2015.
Keystone XL	
February 2012	We sent a letter to the U.S. Department of State (**DOS**) informing the DOS that we planned to file a Presidential Permit application in the near future for Keystone XL. We also informed the DOS that the Cushing to U.S. Gulf Coast portion of Keystone XL would be constructed outside of the Presidential Permit process.
May 2012	We filed a Presidential Permit application (cross-border permit) with the DOS for Keystone XL to transport crude oil from the U.S./Canada border in Montana to Steele City, Nebraska. We continued to work with the Nebraska Department of Environmental Quality (**NDEQ**) and various other stakeholders throughout 2012 to determine an alternative route in Nebraska that would avoid the Nebraska Sandhills. We proposed an alternative route to the NDEQ in April 2012, and then modified the route in response to comments from the NDEQ and other stakeholders.
September 2012	We submitted a Supplemental Environmental Report to the NDEQ for the proposed reroute for Keystone XL in Nebraska, and provided an environmental report to the DOS, required as part of the DOS review of our cross-border permit application.
January 2013	The NDEQ issued its final evaluation report on our proposed reroute of Keystone XL to the Governor of Nebraska. In January 2013, the Governor of Nebraska approved our proposed reroute. The NDEQ issued its final evaluation report noting that construction and operation of Keystone XL is expected to have minimal environmental impacts in Nebraska.
March 2013	The DOS released its Draft Supplemental Environmental Impact Statement for Keystone XL. The impact statement reaffirmed construction of the 830,000 Bbl/d Keystone XL project would not result in any significant impact to the environment.
January 2014	The DOS released its Final Supplemental Environmental Impact Statement (**FSEIS**) for the Keystone XL project. The results included in the report were consistent with previous environmental reviews of Keystone XL. The FSEIS concluded Keystone XL is unlikely to significantly impact the rate of extraction in the oil sands and that all other alternatives to Keystone XL are less efficient methods of transporting crude oil, and would result in significantly more greenhouse gas (**GHG**) emissions, oil spills and risks to public safety. The report initiated the National Interest Determination period of up to 90 days which involves consultation with other governmental agencies and provides an opportunity for public comment.
February 2014	A Nebraska district court ruled that the state Public Service Commission, rather than Governor Dave Heineman, has the authority to approve an alternative route through Nebraska for Keystone XL.
April 2014	The DOS announced that the national interest determination period has been extended indefinitely to allow them to consider the potential impact of the Nebraska portion of the pipeline route.
September 2014	Nebraska's Attorney General filed an appeal which was heard by the Nebraska State Supreme Court. We filed a certification petition for Keystone XL with the South Dakota Public Utilities Commission (**PUC**). This certification confirms that the conditions under which Keystone XL's original June 2010 PUC construction permit was granted continue to be satisfied. The formal hearing for the certification is scheduled for May 2015.

Date	Description of development
January 2015	The Nebraska State Supreme Court vacated the lower court's ruling that the law was unconstitutional. As a result, the Governor's January 2013 approval of the alternate route through Nebraska for Keystone XL remains valid. Landowners have filed lawsuits in two Nebraska counties seeking to enjoin Keystone XL from condemning easements on state constitutional grounds.
January 2015	The DOS reinitiated the national interest review and requested the eight federal agencies, with a role in the review, to complete their consideration of whether Keystone XL serves the national interest and to provide their views to the DOS by February 2, 2015.
February 2015	The U.S. Environmental Protection Agency (**EPA**) posted a comment letter to its website suggesting that, among other things, the FSEIS issued by the DOS has not fully and completely assessed the environmental impacts of Keystone XL and that, at lower oil prices, Keystone XL may increase the rates of oil sands production and greenhouse gas emissions. We sent a letter to the DOS refuting these and other comments in the EPA letter but also offering to work with the DOS to ensure it has all the relevant information to allow it to reach a decision to approve Keystone XL. The timing and ultimate approval of Keystone XL remain uncertain. In the event the project does not proceed as planned, we would reassess and reduce its carrying value to its recoverable amount if necessary and appropriate. The estimated capital costs for Keystone XL are expected to be approximately US$8.0 billion. As of December 31, 2014, we had invested US$2.4 billion in the project and have also capitalized interest in the amount of $0.4 billion.
Keystone Hardisty Terminal	
March 2012	We launched and concluded a binding open season to obtain commitments from interested parties for the Keystone Hardisty Terminal.
May 2012	We announced that we had secured binding long-term commitments of more than 500,000 Bbl/d for the Keystone Hardisty Terminal, and are expanding the proposed two million barrel project to a 2.6 million barrel terminal at Hardisty, Alberta, due to strong commercial support.
Fourth Quarter 2014	The Keystone Hardisty Terminal will be constructed in conjunction with Keystone XL and is expected to be completed approximately two years from the date the Keystone XL permit is received.
Energy East Pipeline	
April 2013	We announced that we were holding an open season to obtain firm commitments for a pipeline to transport crude oil from western receipt points to eastern Canadian markets. The open season followed a successful expression of interest phase and discussions with prospective shippers.
August 2013	We announced that we were moving forward with the 1.1 million Bbl/d Energy East Pipeline as it received approximately 900,000 Bbl/d of firm, long-term contracts in its open season to transport crude oil from western Canada to eastern refineries and export terminals. The project is estimated to cost approximately $12 billion, excluding the transfer value of Canadian Mainline natural gas assets. We began Aboriginal and stakeholder engagement and associated field work as part of our initial design and planning.
March 2014	We filed the project description for the Energy East Pipeline with the NEB. This was the first formal step in the regulatory process to receive the necessary approvals to build and operate the pipeline.
October 2014	We filed the necessary regulatory applications for approvals to construct and operate the Energy East Pipeline and terminal facilities with the NEB. The project is estimated to cost approximately $12 billion, excluding the transfer value of Canadian Mainline natural gas assets. Subject to regulatory approvals, the pipeline is anticipated to commence deliveries by the end of 2018.
December 2014	The Energy East Pipeline includes a proposed marine terminal near Cacouna, Québec which would be adjacent to a beluga whale habitat. The Committee on the Status of Endangered Wildlife in Canada recommended that beluga whales be placed on the endangered species list. As a result, we have made the decision to halt any further work at Cacouna and will be analyzing the recommendation, assessing any impacts to the project and reviewing all viable options. We intend to make a decision on how to proceed by the end of first quarter 2015. The 1.1 million Bbl/d Energy East Pipeline received approximately one million Bbl/d of firm, long-term contracts to transport crude oil from western Canada that were secured during binding open seasons.
Northern Courier Pipeline	
August 2012	We announced that we were selected by Fort Hills Energy Limited Partnership (**FHELP**) to design, build, own and operate the proposed Northern Courier Pipeline. The pipeline system is fully subscribed under a long-term contract to service the Fort Hills mine, which is jointly owned by Suncor Energy Inc. (**Suncor**) and two other companies.
April 2013	We filed a permit application with the Alberta Energy Regulator (**AER**) after completing the required Aboriginal and stakeholder engagement and associated field work.
October 2013	Suncor announced that the FHELP was proceeding with the Fort Hills oil sands mining project and that it expected to begin producing crude oil in 2017.
July 2014	The AER issued a permit approving our application to construct and operate the Northern Courier Pipeline. Construction has started on the $900 million, 90 km (56 miles) pipeline to transport bitumen and diluent between the Fort Hills mine site and Suncor's terminal located north of Fort McMurray, Alberta. We currently expect the pipeline to be ready for service in 2017.

Date	Description of development
Heartland Pipeline and TC Terminals	
May 2013	We announced we had reached binding long-term shipping agreements to build, own and operate the Heartland Pipeline and TC Terminals projects, and filed a permit application for the terminal facility.
October 2013	We filed a permit application for the pipeline with the AER after completing the required Aboriginal and stakeholder engagement and associated field work.
February 2014	The application for the terminal facility was approved by the AER.
October 2014	Construction commenced on the terminal. The Heartland Pipeline is a 200 km (125 miles) crude oil pipeline connecting the Edmonton/Heartland, Alberta market region to facilities in Hardisty, Alberta. TC Terminals is a terminal facility in the Heartland industrial area north of Edmonton, Alberta. The pipeline could transport up to 900,000 Bbl/d, while the terminal is expected to have initial storage capacity for up to 1.9 million barrels of crude oil. These projects together have a combined estimated cost of $900 million and are expected to be placed in service in late 2017.
Grand Rapids Pipeline	
October 2012	We announced that we had entered into binding agreements with a partner to develop the Grand Rapids Pipeline, a 460 km (287 miles) crude oil and diluent pipeline system connecting the producing area northwest of Fort McMurray, Alberta to terminals in the Edmonton/Heartland, Alberta region. Our partner has also entered into a long-term transportation service contract in support of the Grand Rapids Pipeline. Along with our partner, we will each own 50 per cent of the project and we will operate the system.
May 2013	We filed a permit application for the Grand Rapids Pipeline with the AER after completing the required Aboriginal and stakeholder engagement and associated field work.
October 2014	The AER issued a permit approving our application to construct and operate the Grand Rapids Pipeline. Construction has commenced with initial crude oil transportation planned in 2016.
Upland Pipeline	
November 2014	We completed a successful binding open season for the Upland Pipeline. The $600 million pipeline would provide crude oil transportation from, and between multiple points in North Dakota and interconnect with the Energy East Pipeline System at Moosomin, Saskatchewan. Subject to regulatory approvals, we anticipate the Upland Pipeline to be in service in 2018. The commercial contracts we have executed for Upland Pipeline are conditioned on Energy East proceeding.

Further information about developments in the Liquids Pipelines business can be found in the MD&A in the *About our business – Strategy, Liquids Pipelines – Results, Liquids Pipelines – Outlook, Liquids Pipelines – Understanding the Liquids Pipelines business* and *Liquids Pipelines – Significant Events* sections, which sections of the MD&A are incorporated by reference herein.

DEVELOPMENTS IN THE ENERGY BUSINESS

Canadian Power

Date	Description of development
Ontario Solar	
June 2013	We completed the acquisition of the first facility for $55 million as per our December 2011 agreement, pursuant to which we agreed to buy nine Ontario solar generation facilities (combined capacity of 86 megawatts (**MW**)) from Canadian Solar Solutions Inc. (**Canadian Solar**), for approximately $500 million. Under the terms of the agreement, Canadian Solar will develop and build each of the nine solar facilities using photovoltaic panels. We buy each facility once construction and acceptance testing are complete and commercial operation begins. All power produced by the solar facilities is currently or will be sold under 20-year Feed-in Tariff (**FIT**) contracts with the IESO.
September 2013	We completed the acquisition of two additional solar facilities for $99 million.
December 2013	We completed the acquisition of an additional solar facility for $62 million.
September 2014	We completed the acquisition of three additional solar facilities for $181 million.
December 2014	We acquired an additional solar facility for $60 million. Our total investment in the eight solar facilities is $457 million.
Napanee	
December 2012	We signed a contract with the Ontario Power Authority (**OPA**) to develop, own and operate a new 900 MW natural gas-fired power plant at Ontario Power Generation's Lennox site in eastern Ontario in the town of Greater Napanee.
January 2015	We began construction activities on the power plant. We expect to invest approximately $1.0 billion in the Napanee facility during construction and commercial operations are expected to begin in late 2017 or early 2018. Production from the facility is fully contracted with the Independent Electricity System Operator (**IESO**).
Bécancour	
June 2012	Hydro-Québec Distribution (**Hydro-Québec**) notified us that it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant through 2013. Under the original agreement, Hydro-Québec had the option to extend the suspension on an annual basis until such time as regional electricity demand levels recover.
June 2013	Hydro-Québec notified us that it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant through 2014.
December 2013	We entered into an amendment to the original suspension agreement with Hydro-Québec to further extend suspension of generation through to the end of 2017. Under the amendment, Hydro-Québec continues to have the option (subject to certain conditions) to further extend the suspension past 2017. The amendment also includes revised provisions intended to reduce Hydro-Québec's payments to us for Bécancour's natural gas transportation costs during the suspension period, although we retain our ability to recover our full capacity costs under the Electricity Supply Contract with Hydro-Québec while the facility is suspended.
May 2014	We received final approval from the Régie de l'énergie for the December 2013 amendment to the original suspension agreement with Hydro-Québec. In addition, Hydro-Québec exercised its option in the amended suspension agreement to extend suspension of all electricity generation to the end of 2017, and requested further suspension of generation to the end of 2018. We continue to receive capacity payments while generation is suspended.
Cancarb Limited and Cancarb Waste Heat Facility	
January 2014	We announced we had reached an agreement for the sale of Cancarb Limited, our thermal carbon black facility, and its related power generation facility.
April 2014	The sale of Cancarb Limited and its related power generation facility, closed for gross proceeds of $190 million. We recognized a gain of $99 million, net of tax, in second quarter 2014.
Bruce Power	
March 2012	Bruce Power received authorization from the Canadian Nuclear Safety Commission to power up the Bruce A Unit 2 reactor.
May 2012	An incident occurred within the Bruce A Unit 2 electrical generator on the non-nuclear side of the plant which delayed the synchronization of Bruce A Unit 2 to the Ontario electrical grid. As a result, Bruce Power submitted a force majeure claim to the OPA.
June 2012	Bruce Power returned Bruce A Unit 3 to service after completing the $300 million West Shift Plus life extension outage, which began in 2011.
August 2012	We confirmed that Bruce Power's force majeure claim to the OPA related to the Bruce A Unit 2 had been accepted. With the acceptance of the force majeure claim, Bruce Power continued to receive the contracted price for power generated from the operating units at Bruce A after July 1, 2012.

Date	Description of development
October 2012	Bruce A Units 1 and 2 were returned to service following the completion of their refurbishment.
November 2012	Both Bruce A Units 1 and 2 have operated at reduced output levels following their return to service, and Bruce Power took Bruce A Unit 1 offline for an approximate one month maintenance outage.
April 2013	Bruce Power announced that it had reached an agreement with the OPA to extend the Bruce B floor price through to the end of the decade, which is expected to coincide with the 2019 and 2020 end of life dates for the Bruce B units.
April 2013	Bruce Power returned Bruce A Unit 4 to service after completing an expanded life extension outage investment program, which began in August 2012. It is anticipated that this investment will allow Bruce A Unit 4 to operate until at least 2021.
March 2014	Cameco Corporation sold its 31.6 per cent limited partnership interest in Bruce B to BPC Generation Infrastructure Trust. We are considering our option to increase our Bruce B ownership percentage.
Fourth Quarter 2014	New Canadian federal legislation is expected to come into force in 2015 respecting the determination of liability and compensation for a nuclear incident in Canada resulting in personal injuries and damages. This proposed legislation will replace existing legislation which currently provides that the licensed operator of a nuclear facility has absolute and exclusive liability and limits the liability to a maximum of $75 million. The proposed new law is fundamentally consistent with the existing regime although the maximum liability will increase to $650 million and increase in increments over three years to a maximum of $1 billion. The operator will also be required to maintain financial assurances such as insurance in the amount of the maximum liability. Our indirect subsidiary owns one third of the common shares of Bruce Power Inc., the licensed operator of Bruce Power, and as such Bruce Power Inc. is subject to this liability in the event of an incident as well as the legislation's other requirements.
Sundance	
July 2012	An arbitration panel decided that the Sundance A PPA should not be terminated and ordered the operator to rebuild Units 1 and 2. The panel also limited the operator's force majeure claim from November 20, 2011 until the units could reasonably be returned to service. The operator announced that it expected the units to be returned to service in the fall of 2013. Since we considered the outages to be an interruption of supply, we accrued $188 million in pretax income between December 2010 and March 2012. The outcome of the decision was that we received approximately $138 million of this amount. We recorded the $50 million difference as a pre-tax charge to second quarter 2012 earnings, of which $20 million related to amounts accrued in 2011. We did not record further revenue or costs from the PPA until the units were returned to service.
November 2012	An arbitration decision was reached with the arbitration panel granting partial force majeure relief to the operator with respect to Sundance B Unit 3, and we reduced our equity earnings by $11 million from the ASTC Power Partnership (**ASTC**) to reflect the amount that will not be recovered as result of the decision. In 2010, Sundance B Unit 3 experienced an unplanned outage related to mechanical failure of certain generator components and was subject to a force majeure claim by the operator. The ASTC, which holds the Sundance B PPA, disputed the claim under the binding dispute resolution process provided in the PPA because we did not believe the operator's claim met the test of force majeure. We therefore recorded equity earnings from our 50 per cent ownership interest in ASTC as though this event were a normal plant outage.
September 2013	Sundance A Unit 1 returned to service.
October 2013	Sundance A Unit 2 returned to service.
Cartier Wind	
November 2012	We placed the second phase of the Gros-Morne wind farm project in service, completing the 590 MW, five phase Cartier Wind Project in Québec. All of the power produced by Cartier Wind is sold to Hydro-Québec under 20-year PPAs.
CrossAlta	
December 2012	We acquired the remaining 40 per cent interests in the Crossfield Gas Storage facility and CrossAlta Gas Storage & Services Ltd. (**CrossAlta**) marketing company from our partner for approximately $214 million cash, net of cash acquired. We now own and operate 100 per cent of the interests of CrossAlta. The acquisition added an additional 27 billion cubic feet (**Bcf**) of working gas storage capacity to our existing portfolio in Alberta.
U.S. Power	
Ravenswood	
September 2014	The 972 MW Unit 30 at the Ravenswood Generating Station experienced an unplanned outage as a result of a problem with the generator associated with the high pressure turbine. Insurance is expected to cover the repair costs and lost revenues associated with the unplanned outage, which are yet to be finalized. As a result of the expected insurance recoveries, net of deductibles, the Unit 30 unplanned outage is not expected to have a significant impact on our earnings, although the recording of earnings may not coincide with lost revenues due to timing of the anticipated insurance proceeds. The unit is expected to be back in service in first half 2015.
New York power business	
June 2012	In 2011, spot prices for capacity sales in the New York Zone J Market were negatively impacted by the manner in which the New York Independent System Operator (**NYISO**) applied pricing rules for a power plant that had recently began service in this market. We jointly filed two formal complaints with the FERC challenging how the NYISO applied its buy-side mitigation rules affecting bidding criteria associated with two new power plants that began service in the New York Zone J markets during the summer of 2011. In June 2012, the FERC addressed the first complaint, indicating it would take steps to increase transparency and accountability for future mitigation exemption tests (**MET**) and decisions.

Date	Description of development
September 2012	The FERC granted an order on the second complaint, directing the NYISO to retest the two new power plants as well as a transmission project currently under construction using an amended set of assumptions to more accurately perform the MET calculations, in accordance with existing rules and tariff provisions. The recalculation was completed in November 2012 and it was determined that one of the plants not owned by us had been granted an exemption in error. That exemption was revoked and the plant is now required to offer its capacity at a floor price which put upward pressure on capacity auction prices since December 2012. The order was prospective only and has no impact on capacity prices for prior periods.
January 2014	Capacity prices in the New York market are established through a series of forward auctions and utilize a demand curve administered price for purposes of setting the monthly spot price. The demand curve, among other inputs, uses assumptions with respect to the expected cost of the most likely peaking generation technology applicable to new entrants to the market. In January 2014, the FERC accepted a new rate for the demand curve that was filed by NYISO as part of its triennial Demand Curve Reset (**DCR**) process. The filing changed the generation technology used in the DCR versus that used during the last reset process for New York City Zone J where Ravenswood operates. This new assumption has the potential to negatively affect Zone J capacity prices in 2015 and 2016. Additionally, another recent FERC decision affecting future capacity auctions in New England Power Pool (**NEPOOL**) may potentially improve capacity price conditions in 2018 and beyond for our assets that are located in NEPOOL.
Fourth Quarter 2014	Average New York Zone J spot capacity prices were approximately 27 per cent higher in 2014 than in 2013. The increase in spot prices and the impact of hedging activities resulted in higher realized capacity prices in New York in 2014.
Natural Gas Storage	
April 2014	We terminated a 38 Bcf long-term natural gas storage contract in Alberta with Niska Gas Storage. The contract contained provisions allowing for possible early termination. As a result, we recorded an after tax charge of $32 million in 2014. We have re-contracted for new natural gas storage services in Alberta with Niska Gas Storage starting May 1, 2014 for a six-year period and a reduced average volume.

Further information about developments in the Energy business can be found in the MD&A in the *About our business – Strategy, Energy – Results, Energy – Outlook, Energy – Understanding the Energy business* and *Energy – Significant Events* sections, which sections of the MD&A are incorporated by reference herein.

Business of TransCanada

We are a leading North American energy infrastructure company focused on Natural Gas Pipelines, Liquids Pipelines and Energy. At Year End and for the year then ended, Natural Gas Pipelines accounted for approximately 48 per cent of revenues and 46 per cent of our total assets, Liquids Pipelines accounted for approximately 15 per cent of revenues and 27 per cent of our total assets' and Energy accounted for approximately 37 per cent of revenues and 24 per cent of our total assets. The following table shows our revenues from operations by segment, classified geographically, for the years ended December 31, 2014 and 2013.

Revenues from operations (millions of dollars)	**2014**	**2013**
Natural Gas Pipelines		
Canada – Domestic	$2,672	$2,718
Canada – Export [1]	881	598
United States	1,163	1,069
Mexico	197	112
	4,913	4,497
Liquids Pipelines		
Canada – Domestic	–	–
Canada – Export [1]	432	399
United States	1,115	725
	1,547	1,124
Energy [2]		
Canada – Domestic	1,349	1,941
Canada – Export [1]	1	–
United States	2,375	1,235
	3,725	3,176
Total revenues [3]	$10,185	$8,797

(1) Exports include pipeline revenues attributable to Canadian Pipeline 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

Our natural gas pipeline network transports natural gas to local distribution companies, power generation facilities and other businesses across Canada, the U.S. and Mexico. We also have regulated natural gas storage facilities in Michigan.

We are the operator of all of the following natural gas pipelines and regulated natural gas storage assets except for Iroquois.

	length	description	effective ownership
Canadian pipelines			
NGTL System	24,525 km (15,239 miles)	Receives, transports and delivers natural gas within Alberta and B.C., and connects with the Canadian Mainline, Foothills system and third-party pipelines	100%
Canadian Mainline	14,114 km (8,770 miles)	Transports natural gas from the Alberta/Saskatchewan border and the Ontario/U.S. border to serve eastern Canada and interconnects to the U.S.	100%
Foothills	1,241 km (771 miles)	Transports natural gas from central Alberta to the U.S. border for export to the U.S. Midwest, Pacific northwest, California and Nevada	100%
Trans Québec & Maritimes (TQM)	572 km (355 miles)	Connects with Canadian Mainline near the Ontario/Québec border to transport natural gas to the Montréal to Québec City corridor, and connects with the Portland pipeline system that serves the northeast U.S.	50%
U.S. pipelines			
ANR Pipeline	15,109 km (9,388 miles)	Transports natural gas from supply basins to markets throughout the mid-west and south to the Gulf of Mexico.	100%
ANR Storage	250 Bcf	Provides regulated underground natural gas storage service from facilities located in Michigan	
Bison	487 km (303 miles)	Transports natural gas from the Powder River Basin in Wyoming to Northern Border in North Dakota. We effectively own 28.3 per cent of the system through our interest in TC PipeLines, LP	28.3%
Gas Transmission Northwest (GTN)	2,178 km (1,353 miles)	Transports natural gas from the WCSB and the Rocky Mountains to Washington, Oregon and California. Connects with Tuscarora and Foothills. We effectively own 49.8 per cent of the system through the combination of our 30 per cent direct ownership interest and our 28.3 per cent interest in TC PipeLines, LP	49.8%
Great Lakes	3,404 km (2,115 miles)	Connects with the Canadian Mainline near Emerson, Manitoba and St Clair, Ontario, plus interconnects with ANR at Crystal Falls and Farwell in Michigan, to transport natural gas to eastern Canada, and the U.S. upper Midwest. We effectively own 66.7 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 28.3 per cent interest in TC PipeLines, LP	66.77%
Iroquois	666 km (414 miles)	Connects with Canadian Mainline near Waddington, New York to deliver natural gas to customers in the U.S. northeast	44.5%
North Baja	138 km (86 miles)	Transports natural gas between Arizona and California, and connects with a third-party pipeline on the California/Mexico border. We effectively own 28.3 per cent of the system through our interest in TC PipeLines, LP	28.3%
Northern Border	2,265 km (1,407 miles)	Transports WCSB and Rockies natural gas with connections to Foothills and Bison to U.S. Midwest markets. We effectively own 14.2 per cent of the system through our 28.3 per cent interest in TC PipeLines, LP	14.2%

	length	description	effective ownership
U.S. pipelines			
Portland	474 km (295 miles)	Connects with TQM near East Hereford, Québec, to deliver natural gas to customers in the U.S. northeast	61.7%
Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to markets in northeastern California and northwestern Nevada. We effectively own 28.3 per cent of the system through our interest in TC PipeLines, LP	28.3%
TC Offshore	958 km (595 miles)	Gathers and transports natural gas within the Gulf of Mexico with subsea pipeline and seven offshore platforms to connect in Louisiana with our ANR pipeline system.	100%
Mexican pipelines			
Guadalajara	310 km (193 miles)	Transports natural gas from Manzanillo, Colima to Guadalajara, Jalisco	100%
Tamazunchale	365 km (227 miles)	Transports natural gas from Naranjos, Veracruz in east central Mexico to Tamazunchale, San Luis Potosi and on to to El Sauz, Queretaro	100%
Under construction			
Mazatlan Pipeline	413 km (257 miles)	To deliver natural gas from El Oro to Mazatlan, Sinaloa in Mexico. Will connect to the Topolobampo Pipeline at El Oro	100%
Topolobampo Pipeline	530 km (329 miles)	To deliver natural gas to Topolobampo, Sinaloa, from interconnects with third-party pipelines in El Oro, Sinaloa and El Encino, Chihuahua in Mexico	100%
In development			
Alaska LNG Pipeline	1,448 km* (900 miles)	To transport natural gas from Prudhoe Bay to LNG facilities in Nikiski, Alaska	25%
Coastal GasLink	670 km* (416 miles)	To deliver natural gas from the Montney gas producing region at an expected interconnect on NGTL near Dawson Creek, B.C. to LNG Canada's proposed LNG facility near Kitimat, B.C.	100%
Prince Rupert Gas Transmission	900 km* (559 miles)	To deliver natural gas from the North Montney gas producing region at an expected interconnect on NGTL near Fort St. John, B.C. to the proposed Pacific Northwest LNG facility near Prince Rupert, B.C.	100%
North Montney Mainline	301 km* (187 miles)	An extension of the NGTL System to receive natural gas from the North Montney gas producing region and connect to NGTL's existing Groundbirch Mainline and the proposed Prince Rupert Gas Transmission project	100%
Merrick Mainline	260 km* (161 miles)	To deliver natural gas from NGTL's existing Groundbirch Mainline near Dawson Creek, B.C. to its end point near the community of Summit Lake, B.C.	100%
Eastern Mainline	245 km* (152 miles)	Various pipeline and compression facilities expected to be added in the Eastern Triangle of the Canadian Mainline to meet the requirements of the existing shippers as well as new firm service requirements following the conversion of components of the Mainline to facilitate the Energy East project	100%
** NGTL 2016/17 Facilities**	540 km* (336 miles)	The expansion program comprised of 21 integrated projects of pipes, compression and metering to meet new incremental firm service requests on the NGTL System	100%

* Pipe lengths are estimates as final route is still under design
** Facilities are not shown on the map

Further information about our pipeline holdings, developments and opportunities and significant regulatory developments which relate to Natural Gas Pipelines can be found in the MD&A in the *Natural Gas Pipelines – Results, Natural Gas Pipelines – Understanding the Natural Gas Pipelines Business* and *Natural Gas Pipelines – Significant Events* sections, which sections of the MD&A are incorporated by reference herein.

LIQUIDS PIPELINES BUSINESS

Our existing liquids pipeline infrastructure connects Alberta and U.S. crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas, as well as connecting U.S. crude oil supplies from the Cushing, Oklahoma hub to refining markets in the U.S. Gulf Coast. Our proposed future pipeline infrastructure would also connect Canadian and U.S. crude oil supplies to refining markets in eastern Canada and overseas export markets, expand Canadian and U.S. crude oil to U.S. markets and connect condensate supplies to U.S. and Canadian markets.

We are the operator of all of the following pipelines and properties.

	length	description	ownership
Liquids pipelines			
Keystone Pipeline System	4,247 km (2,639 miles)	Transports crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka Illinois, Cushing, Oklahoma, and Port Arthur, Texas	100%
Cushing Marketlink		Transports crude oil from the market hub at Cushing, Oklahoma to the Port Arthur, Texas refining market on facilities that form part of the Keystone Pipeline System	100%
Under construction			
Houston Lateral and Houston Terminal	77 km (48 miles)	To extend the Keystone Pipeline System to the Houston, Texas refining market	100%
Keystone Hardisty Terminal		Crude oil terminal located at Hardisty, Alberta, providing western Canadian producers with crude oil batch accumulation tankage and access to the Keystone Pipeline System	100%
Grand Rapids Pipeline	460 km (287 miles)	To transport crude oil and diluent between the producing area northwest of Fort McMurray, Alberta and the Edmonton/Heartland, Alberta market region	50%
Northern Courier Pipeline	90 km (56 miles)	To transport bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta	100%
In development			
Bakken Marketlink		To transport crude oil from the Williston Basin producing region in North Dakota and Montana to Cushing, Oklahoma on facilities that form part of Keystone XL	100%
Keystone XL	1,897 km (1,179 miles)	To transport crude oil from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System	100%
Heartland Pipeline and TC Terminals	200 km (125 miles)	Terminal and pipeline facilities to transport crude oil from the Edmonton/Heartland, Alberta region to facilities in Hardisty, Alberta	100%
Energy East Pipeline	4,600 km (2,850 miles)	To transport crude oil from western Canada to eastern Canadian refineries and export markets	100%
Upland Pipeline	460 km (285 miles)	To transport crude oil from, and between, multiple points in North Dakota and interconnect with the Energy East Pipeline at Moosomin, Saskatchewan	100%

Further information about our pipeline holdings, developments and opportunities and significant regulatory developments which relate to Liquids Pipelines can be found in the MD&A in the *Liquids Pipelines – Results, Liquids Pipelines – Understanding the Liquids Pipelines business* and *Liquids Pipelines – Significant Events* sections, which sections of the MD&A are incorporated by reference herein.

REGULATION OF THE NATURAL GAS AND LIQUIDS PIPELINES BUSINESSES

Canada

Natural Gas Pipelines

The Canadian Mainline, NGTL System and most of the other Canadian pipelines owned or operated by TransCanada (collectively, the **Systems**) are regulated by the NEB under the *National Energy Board Act* (Canada). The NEB regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's Canadian regulated natural gas transmission systems.

The NEB generally 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. Generally, Canadian natural gas pipelines request the NEB to approve the pipeline's cost of service and tolls once a year, and recover or refund the variance between actual and expected revenues and costs in future years. The Canadian Mainline, however, operates under a fixed toll arrangement for its longer term firm transportation service and has the flexibility to price its shorter term and discretionary services in order to maximize its revenue. Further information relating to the decision from the NEB regarding the Canadian Restructuring Proposal as well as the LDC Settlement can be found in the *General Developments of the business – Developments in the Natural Gas Pipelines business – Canadian Mainline, Tolls and Tariff Applications (LDC Settlement)* section above.

New facilities on or associated with the Systems 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 ROE, and any incentive earnings.

Natural Gas Pipelines Projects

The Coastal GasLink and PRGT projects are being proposed and developed primarily under the regulatory regime administered by the OGC and the EAO. The OGC is responsible for overseeing oil and gas operations in B.C., including exploration, development, pipeline transportation and reclamation. The EAO is an agency that manages the review of proposed major projects in B.C., as required by the B.C. *Environmental Assessment Act*.

Liquids Pipelines

The NEB regulates the terms and conditions of service, including rates, facilities and the physical operation of the Canadian portion of the Keystone Pipeline System.

Liquids Pipelines Projects

TC Terminals, Northern Courier Pipeline, and Grand Rapids Pipeline were approved by the AER in February, July and October 2014 respectively. All three projects are currently under construction. The Heartland Pipeline application is currently under regulatory review by the AER. The AER administers approvals required to construct and operate the pipelines and associated facilities in accordance with *Directive 56*, approvals to obtain land access under the *Public Land Act*, and environmental approvals under the *Environmental and Protection Enhancement Act*.

Energy East Pipeline is being proposed and developed under the regulatory regime administered by the NEB.

United States

Natural Gas Pipelines

TransCanada's wholly owned and partially owned U.S. pipelines 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. The ANR System's natural gas storage facilities in Michigan are also regulated by FERC.

Liquids Pipelines

The FERC regulates the terms and conditions of service, including transportation rates, of interstate liquids pipelines, including the U.S. portion of the Keystone Pipeline System and Cushing Marketlink. The siting and construction of pipeline facilities are regulated by the specific state commissions where the pipeline crosses. Pipeline safety is regulated by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration. Liquids pipelines that cross the international border between Canada and the United States, such as the Keystone Pipeline System and the proposed Keystone XL project, are required to obtain a Presidential Permit from the DOS.

Mexico

Natural Gas Pipelines
TransCanada's pipelines in Mexico are regulated by the Comisión Reguladora de Energía or Energy Regulatory Commission who approve construction of new pipeline facilities and ongoing operations of the infrastructure. Our Mexican pipelines have approved tariffs, services and related rates, however, the contracts underpinning the construction and operation of the facilities are long-term negotiated fixed rate contracts. These rates are only subject to change under specific circumstances such as certain types of force majeure events or changes in law.

ENERGY BUSINESS
Our Energy business includes a portfolio of power generation assets in Canada and the U.S., and unregulated natural gas storage assets in Alberta.

We own, control or are developing generation capacity powered by natural gas, nuclear, coal, hydro, wind and solar assets. Our power business in Canada is mainly located in Alberta, Ontario and Québec. Our power business in the U.S. is located in New York, New England, and Arizona. The assets are largely supported by long-term contracts and some represent low cost baseload generation, while others are critically located, essential capacity.

We conduct wholesale and retail electricity marketing and trading throughout North America from our offices in Alberta, Ontario and Massachusetts to actively manage our commodity exposure and provide higher returns.

We own or control unregulated natural gas storage capacity in Alberta and regulated natural gas storage in Michigan (part of the Natural Gas Pipelines segment).

We are the operator of all of our Energy assets, except for the Sheerness, Sundance A and Sundance B PPAs, Cartier Wind, Bruce A and B and Portlands Energy.

	generating capacity (MW)	type of fuel	description	location	ownership
Canadian Power 8,037 MW of power generation capacity (including facilities under construction)					
Western Power 2,609 MW of power supply in Alberta and the western U.S.					
Bear Creek	80	natural gas	Cogeneration plant	Grande Prairie, Alberta	100%
Carseland	80	natural gas	Cogeneration plant	Carseland, Alberta	100%
Coolidge[1]	575	natural gas	Simple-cycle peaking facility	Coolidge, Arizona	100%
Mackay River	165	natural gas	Cogeneration plant	Fort McMurray, Alberta	100%
Redwater	40	natural gas	Cogeneration plant	Redwater, Alberta	100%
Sheerness PPA	756	coal	Output contracted under PPA	Hanna, Alberta	100%
Sundance A PPA	560	coal	Output contracted under PPA	Wabamun, Alberta	100%
Sundance B PPA (Owned by ASTC Power Partnership[2])	353[3]	coal	Output contracted under PPA	Wabamun, Alberta	50%
Eastern Power 2,939 MW of power generation capacity (including facilities under construction)					
Bécancour	550	natural gas	Cogeneration plant	Trois-Rivières, Québec	100%
Cartier Wind	365[3]	wind	Five wind power projects	Gaspésie, Québec	62%
Grandview	90	natural gas	Cogeneration plant	Saint John, New Brunswick	100%
Halton Hills	683	natural gas	Combined-cycle plant	Halton Hills, Ontario	100%
Portlands Energy	275[3]	natural gas	Combined-cycle plant	Toronto, Ontario	50%
Ontario Solar	76	solar	Eight solar facilities	Southern Ontario and New Liskeard, Ontario	100%
Bruce Power 2,489 MW of power generation capacity through eight nuclear power units					
Bruce A	1,467[3]	nuclear	Four operating reactors	Tiverton, Ontario	48.9%
Bruce B	1,022[3]	nuclear	Four operating reactors	Tiverton, Ontario	31.6%

	generating capacity (MW)	type of fuel	description	location	ownership
U.S. Power 3,755 MW of power generation capacity					
Kibby Wind	132	wind	Wind farm	Kibby and Skinner Townships, Maine	100%
Ocean State Power	560	natural gas	Combined-cycle plant	Burrillville, Rhode Island	100%
Ravenswood	2,480	natural gas and oil	Multiple-unit generating facility using dual fuel-capable steam turbine, combined-cycle and combustion turbine technology	Queens, New York	100%
TC Hydro	583	hydro	13 hydroelectric facilities, including stations and associated dams and reservoirs	New Hampshire, Vermont and Massachusetts (on the Connecticut and Deerfield rivers)	100%
Unregulated natural gas storage 118 Bcf of non-regulated natural gas storage capacity					
CrossAlta	68 Bcf		Underground facility connected to the NGTL System	Crossfield, Alberta	100%
Edson	50 Bcf		Underground facility connected to the NGTL System	Edson, Alberta	100%
Under construction					
Napanee	900	natural gas	Combined-cycle plant	Greater Napanee, Ontario	100%

(1) Located in Arizona, results reported in Canadian Power – Western Power.
(2) We have a 50 per cent interest in ASTC Power Partnership, which has a PPA for production from the Sundance B power generating facilities.
(3) Our share of power generation capacity.

We own or have the rights to power supply in Alberta and Arizona through three long-term PPAs, five natural gas-fired cogeneration facilities, and through Coolidge, a simple-cycle, natural gas peaking facility in Arizona.

Power purchased under long-term contracts is as follows:

	Type of contract	With	Expires
Sheerness PPA	Power purchased under a 20-year PPA	ATCO Power and TransAlta Utilities Corporation	2020
Sundance A PPA	Power purchased under a 20-year PPA	TransAlta Utilities Corporation	2017
Sundance B PPA	Power purchased under a 20-year PPA (own 50 per cent through the ASTC Power Partnership)	TransAlta Utilities Corporation	2020

Power sold under long-term contracts is as follows:

	Type of contract	With	Expires
Coolidge	Power sold under a 20-year PPA	Salt River Project Agricultural Improvements & Power District	2031

We own or are developing power generation capacity in eastern Canada. All of the power produced by these assets is sold under long-term contracts.

Assets currently operating under long-term contracts are as follows:

	Type of contract	With	Expires
Bécancour[1]	20-year PPA Steam sold to an industrial customer	Hydro-Québec	2026
Cartier Wind	20-year PPA	Hydro-Québec	2032
Grandview	20-year tolling agreement to buy 100 per cent of heat and electricity output	Irving Oil	2025
Halton Hills	20-year Clean Energy Supply contract	IESO	2030
Portlands Energy	20-year Clean Energy Supply contract	IESO	2029
Ontario Solar[2]	20-year FIT contracts	IESO	2032-2034

(1) Power generation has been suspended since 2008. We continue to receive capacity payments while generation is suspended.
(2) We acquired four facilities in 2013 and an additional four facilities in 2014.

Assets currently under construction are as follows:

	Type of contract	With	Expires
Napanee	20-year Clean Energy Supply contract	IESO	20 years from in-service date

Further information about our Energy holdings and significant developments and opportunities in relation to Energy can be found in the MD&A in the *Energy – Results, Energy – Understanding the Energy business* and *Energy – Significant Events* sections, which sections of the MD&A are incorporated by reference herein.

General

EMPLOYEES
At Year End, TransCanada's principal operating subsidiary, TCPL, had 6,059 full time active employees, substantially all of whom were employed in Canada and the U.S., as set forth in the following table.

Calgary	3,186
Western Canada (excluding Calgary)	497
Eastern Canada	315
Houston	576
U.S. Midwest	464
U.S. Northeast	451
U.S. Southeast/Gulf Coast (excluding Houston)	319
U.S. West Coast	86
Mexico and South America	165
Total	6,059

HEALTH, SAFETY AND ENVIRONMENTAL PROTECTION AND SOCIAL POLICIES
The Health, Safety and Environment committee of TransCanada's Board of Directors (the **Board**) oversees operational risk, people and process safety, security of personnel and environmental risks, and monitors compliance with our health, safety and environment (**HSE**) corporate policy through regular reporting from management. We have an integrated HSE management system that establishes a framework for managing HSE issues that is used to capture, organize and document our related policies, programs and procedures.

Our management system for HSE is modeled after international standards, conforms to external industry consensus standards and voluntary programs, and complies with applicable legislative requirements and various other internal management systems. It follows a continuous improvement cycle organized into four key areas:

- Planning: risk and regulatory assessment, objectives and targets, and structure and responsibility
- Implementing: development and implementation of programs, plans, procedures and practices aimed at operational risk management
- Reporting: document and records management, communication and reporting, and
- Action: ongoing audit and review of HSE performance.

The committee reviews HSE performance and operational risk management on a quarterly basis. It receives detailed reports on:

- overall HSE corporate governance
- operational performance and preventive maintenance metrics
- asset integrity programs
- emergency preparedness, incident response and evaluation
- people and process safety performance metrics, and
- developments in and compliance with applicable legislation and regulations.

The committee also receives updates on any specific areas of operational and construction risk management review being conducted by management and the results and corrective action plans emanating from internal and third party audits.

Environmental policies
TransCanada's facilities are subject to 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 implemented inspection and audit programs designed to keep all of our facilities in compliance with environmental requirements.

Safety and asset integrity
As one of TransCanada's priorities, safety is an integral part of the way our employees work. Since 2008, we have sustained year over year improvement in our safety performance. Overall, TransCanada's incident frequency rates in 2014 continued to meet or exceed most industry benchmarks.

The safety and integrity of our existing and newly developed infrastructure is 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.

TransCanada annually conducts emergency response exercises to practice effective coordination between the Company, local emergency responders, regulatory agencies and government officials in the event of an emergency. TransCanada uses the Incident Command System which supports a unified approach to emergency response with these community members. TransCanada also provides annual training to all field staff in the form of table top exercises, online and vendor lead training.

Social Policies
TransCanada has a number of policies, guiding principles and practices in place to help manage Aboriginal and other stakeholder relations. We have adopted a Code of business ethics (**Code**) which applies to all employees, officers and directors as well as contract workers of TransCanada and its wholly-owned subsidiaries and operated entities in countries where we conduct business. All employees (including executive officers) and directors must certify their compliance with the Code every year. The Code 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 contractors, and serve as a standard for us in our dealings with all stakeholders.

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. Our stakeholder relations framework provides the structure to guide our teams' behavior and actions, so they understand their responsibility and extend respect, courtesy and the opportunity to respond to every stakeholder.

We strive for continuous improvement in how we navigate the interconnections and complexity of environmental, social and economic issues related to our business. These issues are of great importance to our stakeholders, and have an impact on our ability to build and operate energy infrastructure.

Risk factors

A discussion of our risk factors can be found in the MD&A in the *Natural Gas Pipelines – Business Risks, Liquids Pipelines – Business Risks, Energy – Business Risks* and *Other information – Risks and risk management* sections, which sections of the MD&A are incorporated by reference into this AIF.

Dividends

Our 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, our 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 our 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.

Dividends on our preferred shares are payable quarterly, as and when declared by the Board. The dividends declared on our common and preferred shares during the past three completed financial years are set out in the following table:

	2014	2013	2012
Dividends declared on common shares	$1.92	$1.84	$1.76
Dividends declared on Series 1 preferred shares	$1.15	$1.15	$1.15
Dividends declared on Series 2 preferred shares (1)	–	–	–
Dividends declared on Series 3 preferred shares	$1.00	$1.00	$1.00
Dividends declared on Series 5 preferred shares	$1.10	$1.10	$1.10
Dividends declared on Series 7 preferred shares (2)	$1.00	$0.91	–
Dividends declared on Series 9 preferred shares (3)	$1.09	–	–

(1) Issued December 31, 2014. TransCanada announced on December 31, 2014 that 12,501,577 of its 22,000,000 Series 1 preferred shares were tendered for conversion effective December 31, 2014 on a one-for-one basis into Series 2 preferred shares. As a result of the conversion, TransCanada had 9,498,423 Series 1 preferred shares and 12,501,577 Series 2 preferred shares issued and outstanding as at December 31, 2014. The Series 1 preferred shares will pay on a quarterly basis, for the five-year period beginning on December 31, 2014, as and when declared by the Board, a fixed dividend based on an annual rate of 3.266 per cent. The Series 2 preferred shares will pay a floating quarterly dividend for the five-year period beginning on December 31, 2014, as and when declared by the Board. The floating quarterly dividend rate for the Series 2 preferred shares for the first quarterly floating rate period (being the period from December 31, 2014 to but excluding March 31, 2015) is an annual rate of 2.815 per cent which will be reset every quarter.
(2) Issued March 4, 2013.
(3) Issued January 20, 2014.

We increased the quarterly dividend on our outstanding common shares by eight per cent to $0.52 per share for the quarter ending March 31, 2015.

Description of capital structure

SHARE CAPITAL
TransCanada's authorized share capital consists of an unlimited number of common shares, of which 708,662,996 were issued and outstanding at Year End, and an unlimited number of first preferred shares and second preferred shares, issuable in series, of which the following were issued and outstanding as at Year End, or as otherwise indicated below.

First Preferred Shares	Issued and Outstanding	Convertible to
Series 1 preferred shares	9,498,423	Series 2 preferred shares
Series 2 preferred shares (1)	12,501,577	Series 1 preferred shares
Series 3 preferred shares	14,000,000	Series 4 preferred shares
Series 5 preferred shares	14,000,000	Series 6 preferred shares
Series 7 preferred shares	24,000,000	Series 8 preferred shares
Series 9 preferred shares (2)	18,000,000	Series 10 preferred shares

(1) Issued upon conversion of Series 1 preferred shares on December 31, 2014.
(2) Issued January 20, 2014.

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.

We have a shareholder rights 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 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 (**an acquiring person**), 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 plan (**a permitted bid**). Prior to a flip-in event (as described below), each right permits registered holders to purchase from the Company common shares of TransCanada at an 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 permitted bid, is referred to as a *flip-in event*. Ten trading days after a flip-in event, each right will permit registered holders other than an acquiring person to receive, upon payment of the exercise price, the number of common shares with an aggregate market price equal to twice the exercise price.

TransCanada has a dividend reinvestment and share purchase plan (**DRP**) which permits eligible holders of TransCanada common or preferred shares and preferred shares of TCPL to elect to reinvest their dividends and make optional cash payments to buy TransCanada common shares acquired on the open market at 100 per cent of the weighted average purchase price. 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 DRP.

TransCanada also has stock based compensation plans that allow some employees to purchase common shares of TransCanada. Option exercise prices are equal to the closing price on the Toronto Stock Exchange (**TSX**) on the last trading day immediately preceding the grant date. Options granted under the plans 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 its liquidation, dissolution or winding up.

Except as provided by the CBCA, 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 holders of Series 1, 3, 5, 7 and 9 preferred shares will be entitled to receive quarterly five-year fixed rate cumulative preferential cash dividends, as and when declared by the Board, at an annualized rate equal to the sum of the then five-year Government of Canada bond yield, calculated at the start of the applicable five-year period, and a spread as set forth in the table below and have the right to convert their shares into cumulative redeemable Series 2, 4, 6, 8, and 10 preferred shares, respectively, subject to certain conditions, on such conversion dates as set forth in the table below. The Series 1, 3, 5, 7 and 9 preferred shares are redeemable by TransCanada in whole or in part on such redemption dates as set forth in the table below, 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 2, 4, 6, 8 and 10 preferred shares will be entitled to receive quarterly floating rate cumulative preferential cash dividends, as and when declared by the Board, at an annualized rate equal to the sum of the then 90-day Government of Canada treasury bill rate, recalculated quarterly, and a spread as set forth in the table below and have the right to convert their shares into Series 1, 3, 5, 7 and 9 preferred shares, respectively, subject to certain conditions, on such conversion dates as set forth in the table below. The Series 2, 4, 6, 8 and 10 preferred shares are redeemable by TransCanada in whole or in part after their respective initial redemption date as set forth in the table below, by the payment of an amount in cash for each share to be redeemed equal to (i) $25.00 in the case of redemptions on such redemption dates as set out in the table below, or (ii) $25.50 in the case of redemptions on any other date, in each case plus all accrued and unpaid dividends thereon.

In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 1, 2, 3, 4, 5, 6, 7, 8, 9 and 10 preferred shares shall be entitled to receive $25.00 per preferred share plus all accrued and unpaid dividends thereon in preference over the common shares or any other shares ranking junior to the first preferred shares.

Series of First Preferred Shares	Initial Redemption Date	Redemption/Conversion Dates	Spread (%)
Series 1 preferred shares	–	December 31, 2019 and every fifth year thereafter	1.92
Series 2 preferred shares	December 31, 2014	December 31, 2019 and every fifth year thereafter	1.92
Series 3 preferred shares	–	June 30, 2015 and every fifth year thereafter	1.28
Series 4 preferred shares	June 30, 2015	June 30, 2020 and every fifth year thereafter	1.28
Series 5 preferred shares	–	January 30, 2016 and every fifth year thereafter	1.54
Series 6 preferred shares	January 30, 2016	January 30, 2021 and every fifth year thereafter	1.54
Series 7 preferred shares	–	April 30, 2019 and every fifth year thereafter	2.38
Series 8 preferred shares	April 30, 2019	April 30, 2024 and every fifth year thereafter	2.38
Series 9 preferred shares	–	October 30, 2019 and every fifth year thereafter	2.35
Series 10 preferred shares	October 30, 2019	October 30, 2024 and every fifth year thereafter	2.35

Except as provided by the CBCA, the respective holders of the first preferred shares of each outstanding series 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 on such series of preferred shares, whether or not consecutive, in which case the holders of the first preferred shares of such series 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 of the first preferred share of such series, until all arrears of dividends have been paid. Subject to the CBCA, the series provisions attaching to the first 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 Corporation 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**) and its outstanding preferred shares have also been assigned credit ratings by Moody's, S&P and DBRS Limited (**DBRS**). 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 Corporation 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 the Company and TCPL which have been rated by DBRS, Moody's and S&P:

	DBRS	Moody's	S&P
Senior unsecured debt			
Debentures	A (low)	A3	A-
Medium-term notes	A (low)	A3	A-
Junior subordinated notes	BBB	Baa1	BBB
Preferred shares	Pfd-2 (low)	Baa2	P-2
Commercial paper	R-1 (low)	–	A-2
Trend/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.

Each of the Company and TCPL paid fees to each of DBRS, Moody's and S&P for the credit ratings rendered their outstanding classes of securities noted above. Other than annual monitoring fees for the Company and TCPL and their rated securities, no additional payments were made to DBRS, Moody's and S&P in respect of any other services provided to us during the past two years.

The information concerning our credit ratings relates to our financing costs, liquidity and operations. The availability of our funding options may be affected by certain factors, including the global capital market environment and outlook as well as our financial performance. Our access to capital markets at competitive rates is dependent on our credit rating and rating outlook, as determined by credit rating agencies such as DBRS, Moody's and S&P, and if our ratings were downgraded TransCanada'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

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 and other than in respect of DBRS' ratings of commercial paper and short-term debt, which utilize *high, middle* and *low* subcategories for its R-1 and R-2 rating categories. In respect of long-term debt and preferred share ratings, the absence of either a *high* or *low* designation indicates the rating is in the middle of the category. The R-1 (low) rating assigned to TCPL's short-term debt is in the third highest of 10 rating categories and indicates good credit quality. The capacity for payment of short-term financial obligations as they fall due is substantial. The overall strength is not as favourable as higher rating categories. Short-term debt rated R-1 (low) may be vulnerable to future events, but qualifying negative factors are considered manageable. The A (low) 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 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 long-term debt rated BBB 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 companies whose long-term debt is rated in the A category.

MOODY'S

Moody's has different rating scales for short- and long-term obligations. Numerical modifiers 1, 2 and 3 are appended to each rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and a modifier 3 indicates a ranking in the lower end of that generic rating category. 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 judged to be 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 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 judged to be medium-grade and are subject to moderate credit risk and, as such, may possess certain speculative characteristics.

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 somewhat 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 eight rating categories for short-term debt issuers. Short-term debt issuers rated A-2 have satisfactory capacity to meet their financial commitments, however they are somewhat more susceptible to adverse effects of changes in circumstances and economic conditions than obligors in the highest rating category. The BBB rating assigned to TCPL's junior subordinated notes is in the fourth highest of ten rating categories for long-term debt obligations and the P-2 rating assigned to TransCanada's preferred shares is the second highest of eight rating categories for Canadian preferred shares. The BBB and P-2 ratings assigned to TCPL's junior subordinated notes and TransCanada's preferred shares exhibit 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 TSX and the New York Stock Exchange (**NYSE**) under the symbol TRP. Our Series 1, 2, 3, 5, 7 and 9 preferred shares have been listed for trading on the TSX since September 30, 2009, December 31, 2014, March 11, 2010, June 29, 2010, March 4, 2013 and January 20, 2014 under the symbols TRP.PR.A, TRP.PR.F, TRP.PR.B, TRP.PR.C, TRP.PR.D, and TRP.PR.E, respectively. The following tables set out 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 respective Series 1, 2, 3, 5, 7 and 9 preferred shares on the TSX, for the period indicated:

COMMON SHARES

	TSX (TRP)				NYSE (TRP)			
Month	**High ($)**	**Low ($)**	**Close ($)**	**Volume Traded**	**High (US$)**	**Low (US$)**	**Close (US$)**	**Volume Traded**
December 2014	$58.18	$51.47	$57.10	39,181,474	$51.06	$44.40	$49.10	27,293,987
November 2014	$57.98	$53.87	$54.45	29,512,092	$51.44	$47.21	$48.16	27,196,711
October 2014	$58.03	$49.30	$55.55	46,346,061	$51.84	$43.71	$49.29	44,973,083
September 2014	$63.86	$56.74	$57.68	49,632,379	$58.40	$51.02	$51.53	47,530,203
August 2014	$58.74	$53.19	$58.43	25,578,084	$54.05	$48.78	$53.78	25,280,599
July 2014	$56.34	$50.38	$54.70	29,465,223	$52.27	$47.24	$50.17	15,367,685
June 2014	$51.45	$50.02	$50.93	20,404,127	$48.13	$45.72	$47.72	9,386,604
May 2014	$51.76	$50.41	$50.48	15,956,228	$47.52	$46.17	$46.65	9,026,941
April 2014	$51.89	$49.34	$51.08	22,553,336	$47.25	$44.78	$46.63	11,068,870
March 2014	$50.97	$48.50	$50.25	17,476,864	$45.65	$43.73	$45.52	9,005,406
February 2014	$50.24	$47.43	$48.74	18,422,252	$45.71	$42.73	$44.03	10,356,246
January 2014	$49.29	$47.14	$48.42	22,672,643	$45.81	$42.21	$43.44	12,501,327

PREFERRED SHARES

	Preferred Shares					
Month	**Series 1**	**Series 2**	**Series 3**	**Series 5**	**Series 7**	**Series 9**
December						
High	$21.50	$22.85	$18.49	$21.98	$25.55	$25.73
Low	$19.18	$22.41	$17.02	$18.61	$24.79	$25.00
Close	$21.20	$22.61	$17.92	$21.53	$25.28	$25.43
Volume Traded	1,886,935	37,025	511,512	488,294	350,740	345,413
November						
High	$22.29	–	$19.29	$22.48	$25.59	$25.69
Low	$21.40	–	$18.48	$21.55	$25.05	$25.20
Close	$21.50	–	$18.54	$21.86	$25.53	$25.56
Volume Traded	961,356	–	614,216	238,730	196,566	798,443
October						
High	$22.68	–	$19.53	$21.74	$25.33	$25.60
Low	$21.34	–	$18.48	$20.54	$24.76	$25.00
Close	$21.80	–	$18.95	$21.69	$25.12	$25.29
Volume Traded	801,630	–	229,370	312,713	156,322	291,498
September						
High	$23.19	–	$20.04	$22.88	$25.45	$25.68
Low	$22.30	–	$19.06	$21.23	$24.50	$24.77
Close	$22.61	–	$19.39	$21.44	$24.95	$25.05
Volume Traded	296,706	–	213,145	127,510	281,562	569,846
August						
High	$23.47	–	$20.27	$22.79	$25.50	$25.80
Low	$22.81	–	$19.56	$22.19	$25.20	$25.34
Close	$23.14	–	$19.72	$22.65	$25.45	$25.69
Volume Traded	150,425	–	150,841	91,404	257,107	215,759

	Preferred Shares					
Month	**Series 1**	**Series 2**	**Series 3**	**Series 5**	**Series 7**	**Series 9**
July						
High	$23.59	–	$20.50	$22.65	$25.38	$25.55
Low	$23.10	–	$19.93	$22.07	$25.08	$25.26
Close	$23.40	–	$20.01	$22.45	$25.15	$25.47
Volume Traded	289,811	–	169,917	202,331	382,076	172,975
June						
High	$23.84	–	$20.48	$23.16	$25.24	$25.59
Low	$23.01	–	$20.02	$22.22	$24.35	$24.88
Close	$23.24	–	$20.35	$22.59	$25.24	$25.39
Volume Traded	330,251	–	371,671	133,102	213,689	161,055
May						
High	$24.48	–	$21.45	$23.40	$25.69	$25.68
Low	$23.16	–	$20.40	$22.71	$24.76	$25.02
Close	$23.16	–	$20.40	$23.01	$24.76	$25.11
Volume Traded	375,099	–	425,887	479,657	367,889	224,933
April						
High	$24.24	–	$20.94	$22.99	$25.53	$25.62
Low	$23.28	–	$20.19	$21.91	$24.73	$25.13
Close	$24.19	–	$20.89	$22.94	$25.53	$25.62
Volume Traded	731,585	–	332,360	826,978	406,590	1,109,855
March						
High	$23.61	–	$20.50	$22.71	$25.11	$25.27
Low	$23.00	–	$19.97	$21.75	$24.76	$24.99
Close	$23.23	–	$20.13	$21.93	$24.95	$25.17
Volume Traded	1,770,656	–	575,485	492,867	389,277	607,229
February						
High	$23.52	–	$20.47	$22.41	$25.00	$25.12
Low	$23.02	–	$20.11	$21.80	$24.60	$24.75
Close	$23.12	–	$20.39	$22.30	$24.97	$25.10
Volume Traded	244,713	–	357,933	502,010	430,852	969,637
January						
High	$24.47	–	$20.67	$22.42	$25.30	$24.99
Low	$23.10	–	$20.13	$21.56	$24.60	$24.74
Close	$23.28	–	$20.44	$22.11	$24.79	$24.78
Volume Traded	474,850	–	192,252	177,153	1,860,968	1,452,897

TCPL's cumulative redeemable first preferred shares, series Y, were listed on the TSX under the symbol TCA.PR.Y until their redemption on March 5, 2014.

SERIES Y PREFERRED SHARES

	Series Y (TCA.PR.Y)			
Month	**High ($)**	**Low ($)**	**Close ($)**	**Volume Traded**
March 2014	$50.25	$50.24	$50.25	2,060
February 2014	$50.25	$50.13	$50.25	37,465
January 2014	$50.36	$49.85	$50.15	151,322

Directors and officers

As of February 12, 2015, the directors and officers of TransCanada as a group beneficially owned, or exercised control or direction over, directly or indirectly, an aggregate of 441,744 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 directors who serve on the Board, as of February 12, 2015 (unless otherwise indicated), together with their jurisdictions of residence, all positions and offices held by them with TransCanada, 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	Corporate director. Director, Calgary Airport Authority from January 2010 to December 2013.	2005
Derek H. Burney[(1)], O.C. Ottawa, Ontario Canada	Senior strategic advisor, Norton Rose Fulbright (law firm). Chairman, GardaWorld International's (risk management and security services) Advisory Board since April 2008. Advisory Board member, Paradigm Capital Inc. (investment dealer) since 2011. Chair, Canwest Global Communications Corp. (media and communications) from August 2006 (director since April 2005) to October 2010.	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. (food retail) since January 2001. Director, Royal Bank of Canada (chartered bank) from October 1991 to March 2014 and Chair, RBC Dexia Investors Trust until October 2011.	2002
Russell K. Girling[(2)] Calgary, Alberta Canada	President and Chief Executive Officer, TransCanada since July 2010. Chief Operating Officer from July 2009 to June 2010 and President, Pipelines from June 2006 to June 2010. Director, Agrium Inc. (agricultural) since May 2006.	2010
S. Barry Jackson Calgary, Alberta Canada	Corporate director. Chair of the Board, TransCanada since April 2005. Director, WestJet Airlines Ltd. (airline) since February 2009 and Laricina Energy Ltd. (oil and gas, exploration and production) since December 2005. Director, Nexen Inc. (**Nexen**) (oil and gas, exploration and production) from 2001 to June 2013, Chair of the board, Nexen from 2012 to June 2013.	2002
Paula Rosput Reynolds Seattle, Washington U.S.A.	President and Chief Executive Officer, PreferWest, LLC (business advisory group) since October 2009. Director, BAE Systems plc. (aerospace, defence, information security) since April 2011 and Delta Air Lines, Inc. (airline) since August 2004. Director, Anadarko Petroleum Corporation (oil and gas, exploration and production) from August 2007 to May 2014.	2011
John Richels Nichols Hills, Oklahoma U.S.A.	President and Chief Executive Officer, Devon Energy Corporation (**Devon**) (oil and gas, exploration and production, energy infrastructure) since 2010 (President since 2004). Director, Devon since 2007 and BOK Financial Corp. (financial services) since 2013. Chairman, American Exploration and Production Council since May 2012. Former Vice-Chairman of the board of governors, Association of Petroleum Producers.	2013
Mary Pat Salomone[(3)] Naples, Florida U.S.A.	Corporate director. Senior Vice-President and Chief Operating Officer, The Babcock & Wilcox Company (**B&W**) (energy infrastructure) from January 2010 to June 2013. Manager Business Development from 2009 to 2010. Director, United States Enrichment Corporation (basic materials, nuclear) from December 2011 to October 2012.	2013
D. Michael G. Stewart Calgary, Alberta Canada	Corporate director. Director, Pengrowth Energy Corporation (oil and gas, exploration and production) since December 2010. Director, and Audit and Governance committee Chair, Canadian Energy Services & Technology Corp. (chemical, oilfield services) since January 2010. Director, C&C Energia Ltd. (oil and gas) from May 2010 to December 2012 and Orleans Energy Ltd. (oil and gas) from October 2008 to December 2010. Director, Pengrowth Corporation (administrator of Pengrowth Energy Trust) from October 2006 to December 2010.	2006

Name and place of residence	Principal occupation during the five preceding years	Director since
Siim A. Vanaselja[4] Westmount, Québec Canada	Corporate Director. Executive Vice-President and Chief Financial Officer of BCE Inc. (telecommunications and media) since January 2001. Director, Bell Media since March 2011, Bell Aliant Regional Communication Inc. since July 2008, BCE Ventures Inc. since April 2002 and Bimcor Inc. since November 1996. Director, Great-West Lifeco Inc. since May 2014. Director and Audit committee Chair, Maple Leaf Sports and Entertainment Ltd. (sports, property management) since August 2012. Director, CH Group Limited Partnership from August 2009 to August 2012.	2014
Richard E. Waugh Calgary, Alberta Canada	Corporate director. Former Deputy Chairman, President and Chief Executive Officer, The Bank of Nova Scotia (**Scotiabank**) (chartered bank) until January 2014. Director, Catalyst Inc. (non-profit) from February 2007 to November 2013 and Chair, Catalyst Canada Inc. Advisory Board from February 2007 to October 2013.	2012

(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) As President and CEO of TransCanada, Mr. Girling is not a member of any Board Committees, but is invited to attend committee meetings as required.
(3) Ms. Salomone was a director of Crucible Materials Corp. (**Crucible**) from May 2008 to May 1, 2009. On May 6, 2009, Crucible and one of its affiliates filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code in the U.S. Bankruptcy Court for the District of Delaware (the **Bankruptcy Court**). On August 26, 2010, the Bankruptcy Court entered an order confirming Crucible's Second Amended Chapter 11 Plan of Liquidation.
(4) Mr. Vanaselja joined the Board effective May 2, 2014.

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 12, 2015, are identified below. Ms. Reynolds was appointed as the Chair of the Human Resources committee effective May 2, 2014.

Director	Audit committee	Governance committee	Health, Safety and Environment committee	Human Resources committee
Kevin E. Benson	Chair	ü		
Derek H. Burney	ü	Chair		
Paule Gauthier			ü	ü
S. Barry Jackson (Chair)		ü		ü
Paula Rosput Reynolds			ü	Chair
John Richels			ü	ü
Mary Pat Salomone	ü		ü	
D. Michael G. Stewart	ü		Chair	
Siim A. Vanaselja	ü	ü		
Richard E. Waugh		ü		ü

Information about the Audit committee can be found in this AIF under the heading *Audit committee*.

OFFICERS
All of the executive officers and corporate officers of TransCanada reside in Calgary, Alberta, Canada. 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.
James M. Baggs	Executive Vice-President, Operations and Engineering	Prior to March 2014, Senior Vice-President, Operations and Engineering. Prior to June 2012, Vice-President, Operations and Engineering since July 2009.
Kristine L. Delkus	Executive Vice-President, General Counsel and Chief Compliance Officer	Prior to March 2014, Senior Vice-President, Pipelines Law and Regulatory Affairs. Prior to June 2012, Deputy General Counsel, Pipelines and Regulatory Affairs since September 2006 (TCPL).
Wendy L. Hanrahan	Executive Vice-President, Corporate Services	Prior to May 2011, Vice-President, Human Resources since January 2005.
Karl R. Johannson	Executive Vice-President and President, Natural Gas Pipelines	Prior to November 2012, Senior Vice-President, Canadian and Eastern U.S. Pipelines. Prior to January 2011, Senior Vice-President, Power Commercial since January 2006.
Donald R. Marchand	Executive Vice-President and Chief Financial Officer	Prior to July 2010, Vice-President, Finance and Treasurer since September 1999.
Paul E. Miller	Executive Vice-President and President, Liquids Pipelines	Prior to March 2014, Senior Vice-President, Oil Pipelines. Prior to December 2010, Vice-President, Oil Pipelines. Prior to July 2010, Vice-President, Keystone Pipeline since May 2008 (TCPL).
Alexander J. Pourbaix	Executive Vice-President and President, Development	Prior to March 2014, President, Energy and Oil Pipelines. Prior to July 2010, President, Energy Division since June 2006 and Executive Vice-President, Corporate Development since July 2009.
William C. Taylor	Executive Vice-President and President, Energy	Prior to March 2014, Senior Vice-President, U.S. and Canadian Power. Prior to May 2013, Senior Vice-President, Eastern Power. Prior to July 2010, Vice-President and General Manager, U.S. Northeast Power since May 2008 (TCPL).

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 (TCPL).
Ronald L. Cook	Vice-President, Taxation	Vice-President, Taxation since April 2002.
Joel E. Hunter	Vice-President, Finance	Prior to July 2010, Director, Corporate Finance since January 2008.
Christine R. Johnston	Vice-President, Law and Corporate Secretary	Prior to June 2014, Vice-President and Corporate Secretary. Prior to March 2012, Vice-President, Finance Law. Prior to January 2010, Vice-President, Corporate Development Law.
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 any existing or potential conflicts in accordance with TransCanada policies governing directors and officers and in accordance with the CBCA. Our Code covers potential conflicts of interest.

Serving on other boards
The Board believes that it is important for it to be composed of qualified and knowledgeable directors. As a result, due to the specialized nature of the energy infrastructure business, some of our directors are associated with or sit on the boards of companies that ship natural gas or liquids through our pipeline systems. Transmission services on most of TransCanada's pipeline systems in Canada and the U.S. are subject to regulation and accordingly we generally cannot deny transportation services to a creditworthy shipper. The Governance committee monitors relationships among directors to ensure that business associations do not affect the Board's performance.

The Board considers whether directors serving on the boards of all entities including public and private companies, Crown corporations and other state-owned entities, and non-profit organizations pose any potential conflict. The Board reviews these relationships annually to determine that they do not interfere with any of our director's ability to act in our best interests. If a director declares a material interest in any material contract or material transaction being considered at the meeting, the director is not present during the discussion and does not vote on the matter.

Our Code requires employees to receive consent before accepting a directorship with an entity that is not an affiliate. The chief executive officer and executive vice-presidents must receive the consent of the Governance committee. All other employees must receive the consent of their immediate supervisor.

Affiliates
The Board closely oversees relationships between TransCanada and any affiliates to avoid any potential conflicts of interest. This includes our relationship with the TCLP, a master limited partnership listed on the NYSE.

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 TSX and Canadian Securities Administrators:

- National Instrument 52-110, *Audit Committees*
- 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, in each case, 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.*

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.

RELEVANT EDUCATION AND EXPERIENCE OF MEMBERS
The members of the Audit committee as of February 12, 2015 are Kevin E. Benson (Chair), Derek H. Burney, Mary Pat Salomone, D. Michael G. Stewart, and Siim A. Vanaselja. Richard E. Waugh attended the Audit committee meetings as an observer until he retired as Deputy Chairman of Scotiabank on January 31, 2014 and was a voting member of the committee from February 1 until May 2, 2014. Mr. Vanaselja was appointed as a member of the Audit committee effective May 2, 2014.

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 and Mr. Vanaselja are *Audit Committee Financial Experts* 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 is a Chartered Accountant (South Africa) and was a member of the South African Society of Chartered Accountants. He serves as a director of the Winter Sport Institute, and 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 advisor at Norton Rose Fulbright. He 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.

Mary Pat Salomone
Ms. Salomone has a Bachelor of Engineering in Civil Engineering from Youngstown State University and a Master of Business Administration from Baldwin Wallace College. She completed the Advanced Management Program at Duke University's Fuqua School of Buiness in 2011. Ms. Salomone was the Senior Vice-President and Chief Operating Officer of B&W until June 2013. She previously held a number of senior roles with B&W Nuclear, including serving as the Manager of Business Development from 2009 to 2010 and Manager of Strategic Acquisitions from 2008 to 2009, and served as President and Chief Executive Officer of Marine Mechanical Corporation 2001 through 2007, which B&W acquired in 2007.

D. Michael G. Stewart
Mr. Stewart earned a Bachelor of Science in Geological Sciences with First Class Honours from Queen's University. He has served and continues to serve on the boards of several public companies and other organizations and on the audit committee 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 also been active in the Canadian energy industry for over 40 years.

Siim A. Vanaselja
Mr. Vanaselja is a member of the Institute of Chartered Accountants of Ontario and holds an Honours Bachelor of Business degree from the Schulich School of Business. Mr. Vanaselja has been the Executive Vice-President and Chief Financial Officer of BCE Inc. and Bell Canada since January 2001, having previously served as Executive Vice-President and Chief Financial Officer of Bell Canada International. Prior to that, he was a partner at the accounting firm KPMG Canada in Toronto. Mr. Vanaselja has served and continues to serve as a board director for several other companies including Great-West Lifeco Inc. and Maple Leaf Sports and Entertainment Ltd. He has served as a member of the Conference Board of Canada's National Council of Financial Executives, the Corporate Executive Board's Working Council for Chief Financial Officers and Moody's Council of Chief Financial Officers.

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 up to $250,000, 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 $250,000 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 must pre-approve the assignment.

To date, 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 table below shows the services KPMG provided during the last two fiscal years and the fees we paid them:

($ millions)	2014	2013
Audit fees • audit of the annual consolidated financial statements • services related to statutory and regulatory filings or engagements • review of interim consolidated financial statements and information contained in various prospectuses and other securities offering documents	$6.4	$6.4
Audit-related fees • services related to the audit of the financial statements of certain TransCanada post-retirement and post-employment 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	0.5	0.7
All other fees	–	–
Total fees	**$7.1**	**$7.3**

Legal proceedings and regulatory actions

Legal proceedings, arbitrations and actions are part of doing business. While we cannot predict the final outcomes of proceedings and actions with certainty, management does not expect any current proceeding or action to have a material impact on our consolidated financial position, results of operations or liquidity. We are not aware of any potential legal proceeding or action that would have a material impact on our consolidated financial position, results of operations or liquidity.

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, Halifax and Montréal.

Material contracts

TransCanada did not enter into any material contracts outside the ordinary course of business during the year ended December 31, 2014, nor has it entered into any material contracts outside the ordinary course of business prior to the year ended December 31, 2014 which are still in effect as at the date of this AIF.

Interest of experts

KPMG LLP are the auditors of TransCanada and have confirmed that they are independent with respect to TransCanada within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations and also that they are independent accountants with respect to all relevant U.S. professional and regulatory standards.

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.

Glossary

Units of measure

Bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
GWh	Gigawatt hours
MMcf/d	Million cubic feet per day
MW	Megawatt(s)
MWh	Megawatt hours

General terms and terms related to our operations

bitumen	A thick, heavy oil that must be diluted to flow (also see: diluent). One of the components of the oil sands, along with sand, water and clay
Canadian Restructuring Proposal	Canadian Mainline business and services restructuring proposal and 2012 and 2013 Mainline final tolls application
cogeneration facilities	Facilities that produce both electricity and useful heat at the same time
diluent	A thinning agent made up of organic compounds. Used to dilute bitumen so it can be transported through pipelines
Eastern Triangle	Canadian Mainline region between North Bay, Toronto and Montréal
FIT	Feed-in tariff
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it
GHG	Greenhouse gas
HSE	Health, safety and environment
investment base	Includes annual average assets in rate base as well as assets under construction
LNG	Liquefied natural gas
OM&A	Operating, maintenance and administration
PPA	Power purchase arrangement
rate base	Our investment in assets used to provide transportation services on our natural gas pipelines
WCSB	Western Canada Sedimentary Basin

Accounting terms

AFUDC	Allowance for funds using during construction
DRP	Dividend reinvestment plan
ROE	Rate of return on common equity
GAAP	U.S. generally accepted accounting principles

Government and regulatory bodies terms

CFE	Comisión Federal de Electricidad (Mexico)
DOS	Department of State (U.S.)
EPA	Environmental Protection Agency (U.S.)
FERC	Federal Energy Regulatory Commission (U.S.)
IESO	Independent Electricity System Operator
NEB	National Energy Board (Canada)
NYISO	New York Independent System Operator
OPA	Ontario Power Authority (Canada)
RGGI	Regional Greenhouse Gas Initiative (northeastern U.S.)
SEC	U.S. Securities and Exchange Commission

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. 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 consolidated financial statements, annual information form, management's discussion and analysis, all financial information 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 or prospectus supplement relating to the issuance of debt securities 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 consolidated financial statements, management's discussion and analysis and press releases on quarterly financial results;

(c) review and discuss with management and external auditors the use of non-GAAP information and the applicable reconciliation;

(d) review and discuss with management any financial outlook or future-oriented financial information disclosure in advance of its public release; 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 financial projections or presentations to credit rating agencies;

(e) review with management and the external auditors major issues regarding accounting and auditing policies and practices, including any significant changes in the Company's selection or application of accounting policies, 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 findings 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 developments as well as any 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 arbitration and 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 plans and those 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) review the significant findings prepared by the internal audit department and recommendations issued by it 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 subsidiaries and affiliates;
(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 or her any problems or difficulties he or she 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;

(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 any letter, report or other communication from the external auditors in respect of any identified weakness or unadjusted difference and management's response and follow-up, 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) receive and review annually the external auditors' formal written statement of independence delineating all relationships between itself and the Company;
(c) 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;

(ii) any changes required in the planned scope of the audit;

and to report to the Board on such meetings;

(d) meet with the external auditors prior to the audit to review the planning and staffing of the audit;

(e) 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;
(f) review and evaluate the external auditors, including the lead partner of the external auditor team;
(g) 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 that were not pre-approved 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;
  (ii) such services were not recognized by the Company at the time of the engagement to be non-audit services;
  (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) review and approve annually the Statement of Investment Beliefs for the Company's pension plans;
(b) delegate the ongoing administration and management of the financial aspects of the Canadian pension plans to the Pension Committee ("Pension Committee") comprised of members of the Company's management team appointed by the Human Resources Committee, in accordance with the Pension Committee Charter, which terms shall be approved by both the Audit Committee and the Human Resources Committee, and the terms of the Statement of Investment Beliefs;

(c) monitor the financial management activities of the Pension Committee and receive updates at least annually from the Pension Committee on the investment of the Plan assets to ensure compliance with the Statement of Investment Beliefs;
(d) 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;
(e) 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;
(f) receive, review and report to the Board on the actuarial valuation and funding requirements for the Company's pension plans;
(g) approve the initial selection or change of actuary for the Company's pension plans;
(h) approve the appointment or termination of auditors;

IX. U.S. Stock Plans

(a) review and approve the engagement and related fees of the auditor for any plan of a U.S. subsidiary that offers Company stock to employees as an investment option under the plan;

X. 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) oversee succession planning for the senior management in finance, treasury, tax, risk, internal audit and the controllers' group; and

XI. Information Security

(a) review, at least quarterly, the report of the Chief Information Officer (or such other appropriate Company representative) on information security controls, education and awareness.

XII. 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 securities 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, facsimile communication or by other electronic means 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.


Delivering
Results
Positioned for
Growth
TransCanada
In business to deliver
2014
Annual Report



Our Vision

To be the leading energy infrastructure company in North America, focusing on pipeline and power generation opportunities in regions where we have or can develop a significant competitive advantage.

Our Strategic Priorities

Ensuring our $59-billion asset base operates safely, efficiently and generates maximum value for shareholders.

Successful completion of $12 billion in small to medium-sized capital projects by the end of 2017 and $34 billion of commercially secured large-scale projects by the end of the decade.

Capturing additional low-risk opportunities that contribute to earnings growth in the short, medium and long-term.

Maintain our financial strength and flexibility to grow our dividend and continue to prudently fund our industry-leading capital program.

Front Cover:
Completion of the US$600-million extension of the Tamazunchale Pipeline in Mexico demonstrated TransCanada's expertise in engineering, project management and commitment to responsible development.

Our annual report is online, visit our site for more information.
www.transcanada.com

Forward-Looking Information and Non-GAAP Measures These pages contain certain forward-looking information and also contain references to certain non-GAAP measures that do not have any standardized meaning as prescribed by U.S. generally accepted accounting principles (GAAP) and therefore may not be comparable to similar measures presented by other entities. For more information on forward-looking information, the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, and reconciliations of non-GAAP measures to the most closely related GAAP measures, refer to TransCanada's 2014 Annual Report filed with Canadian securities regulators and the U.S. Securities and Exchange Commission and available at TransCanada.com.

Net Income attributable to common shares: $1.7 billion or $2.46 per share
Comparable earnings: $1.7 billion or $2.42 per share [1]
Comparable earnings before interest, taxes, depreciation and amortization: $5.5 billion [1]
Funds generated from operations: $4.3 billion [1]
Capital expenditures, equity investments and acquisitions: $4.9 billion
Common share dividends declared: $1.92 per share

letter to shareholders	A message from President and CEO Russ Girling and Board Chair Barry Jackson pg 03
map and listings	A visual overview of our facilities and new projects across North America pg 08
strategy and competitive advantage	We are delivering value to our shareholders and moving ahead with unprecedented growth pg 10
focus on safety	Maximizing the value of our assets requires operational excellence pg 11
committed to responsible development	We are raising the bar on our performance in order to meet society's rising expectations pg 12
natural gas pipelines	Reinforcing our position as one of North America's leading natural gas transmission providers pg 14
liquids pipelines	Earnings continue to grow as we develop a leading hydrocarbon liquids transportation system pg 16
energy	A diverse portfolio of power generation assets pg 18
positioned for success	The stage is set for significant growth in shareholder value over the long-term pg 20
financial information	Management's discussion and analysis pg 21 Financial statements and notes pg 121 Supplementary information pg 183

We have invested over $40 billion in new assets since 2000 and our shareholders have been rewarded with an average annual return of 15 per cent.

(1) Non-GAAP measures do not have any standardized meaning prescribed by U.S. generally accepted accounting principles (GAAP). For more information see Non-GAAP measures in the Management's Discussion and Analysis of the 2014 Annual Report.

Net Income per Share – Basic
(dollars)



Comparable Earnings per Share [1]
(dollars)



Dividends Declared per Share
(dollars)



Net Income Attributable to Common Shares
(millions of dollars)



Comparable Earnings [1]
(millions of dollars)



Comparable EBITDA [1]
(millions of dollars)



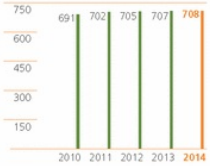
Capital Spending, Equity Investments and Acquisitions
(millions of dollars)



Funds Generated from Operations [1]
(millions of dollars)



Common Shares Outstanding – Average
(millions of shares)



Market Price – Close Toronto Stock Exchange
(dollars)



TransCanada at-a-glance

$59 billion in Assets

Natural Gas Pipelines
68,000 km
(42,100 miles)
368 billion cubic feet (bcf) gas storage capacity

19 **Power Generation Facilities**
10,900 megawatts (MW) generating capacity

Liquids Pipelines
4,250 km
(2,600 miles)



Canada
4,010 employees, in 7 provinces

United States
1,914 employees, in 35 states

Mexico
135 employees, in 7 states

People and Places:
6,059 employees



Russ Girling has been president & CEO for the past four years, leading the development of an unprecedented capital growth plan.



Barry Jackson has served as the chair of TransCanada's Board of Directors since 2002 and has held senior management positions in the oil and gas industry since 1974.

Russ Girling

president
and
chief executive
officer

S. Barry Jackson

chair
of the
board

letter to shareholders

Energy – it is essential to our modern way of life. Whether it's the refined oil used to move our vehicles and make the endless consumer products we use every day, the natural gas that heats our homes and fuels our industry, or the electricity that lights our cities and powers our telecommunications, the world's appetite for affordable energy supplies continues to grow. At the same time, efforts to improve energy efficiency and reduce environmental impacts are presenting new opportunities and challenges for companies like TransCanada that are dedicated to delivering the energy the world needs, safely and reliably.

A Solid Foundation

Building on more than 60 years of experience, TransCanada is playing a central role in developing North America's energy future, as new technology has unlocked oil and gas supplies that are paving the way toward energy self-sufficiency and the ability to export our energy products to meet the needs of overseas markets. Our diverse asset base of natural gas and liquids pipelines, gas storage and power generation facilities provides a solid foundation to realize our vision of becoming North America's leading energy infrastructure company.

2014 was a year of many accomplishments for TransCanada, as we resolved a number of outstanding issues facing our existing business over the last few years, successfully advanced several of our new pipeline and power generation projects and captured more high-quality growth opportunities across the continent. We have created a platform that is expected to transform our company by the end of this decade and drive significant value for shareholders.

"It's clear our strategy is working because it has produced results for our shareholders in the form of an average total annual return of 15 per cent since 2000."

RUSS GIRLING
President and CEO

Positioned for Growth

While 2015 may be challenging for North America's energy industry as enterprises throughout the value chain adjust to lower oil and gas prices, TransCanada is well positioned for this environment thanks to our prudent approach and long-term perspective. This includes ensuring all our assets meet fundamental energy needs that transcend short-term price volatility, along with the additional stability of securing the majority of our existing assets and growth projects under long-term contracts with strong investment-grade counterparties or regulated business models.

Our $46-billion capital program is largely comprised of a diversified mix of natural gas and liquids pipeline projects across Canada, the United States and Mexico backed by either long-term, take-or-pay contracts that average 20 years or more, or a traditional cost-of-service model. This stability buffers an energy infrastructure company like TransCanada from the current volatility of world oil prices, providing predictability and stability for our investors, customers and shareholders.

Even more important is ensuring our existing $59-billion asset base operates safely and reliably, allowing it to deliver the energy people need and value for our shareholders for decades. Layer in a focus of continuing to capture future growth opportunities while maintaining the company's financial strength and flexibility, and you have a strong sense of our overall plan.

Delivering Results

The Board of Directors and TransCanada's executive leadership team firmly believe that our strategy is working and it best positions the company to deliver long-term value to investors by generating significant, sustainable growth in earnings, cash flow and dividends. The results bear that out: Since 2000, our shareholders have realized an average annual total return of 15 per cent including an annual dividend that has increased every year, from $0.80 to $1.92 in 2014. Over the last 15 years, we have grown our asset base from $26 billion to $59 billion and have developed an enviable footprint in Canada, the United States and Mexico. At the same time, we have maintained or improved our top-quartile standings when it comes to the safety and reliability of our assets.

Our base business performed well in 2014 supplemented by new assets that came online and began contributing increased earnings and cash flow. Comparable earnings were $2.42 per share, an eight per cent increase over last year. Funds generated from operations were $4.3 billion, a seven per cent increase from 2013. Earnings and cash flow from our existing asset base, coupled with the $12 billion in short to medium-term growth projects we have underway, provide the confidence in predictable earnings and cash flow growth that supported the board's decision to increase the quarterly dividend by eight per cent for the first quarter of 2015 to $0.52, which is equivalent to $2.08 on an annual basis.

"TransCanada's board and executive leadership team are firmly committed to delivering long-term value to investors through significant and sustainable growth in future cash flow, earnings and dividends."

BARRY JACKSON
Chair of the Board

Maximizing Our Assets

Our top priority continues to be an unwavering focus on maximizing the value of our $59 billion in assets, ensuring they operate safely, efficiently and are being used to their full potential. We moved forward by successfully repositioning some of our key long-haul natural gas pipeline systems that have been under pressure from changing market dynamics in recent years. The longevity of the ANR Pipeline in the United States was secured through long-term commitments that fully contract its Southeast Main Line to move natural gas from the Marcellus and Utica regions to key market destinations for an average term of 23 years.

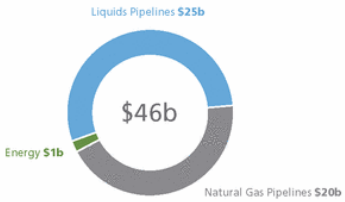
The restructuring of the Canadian Mainline's tolling and service model has resulted in a significant increase in long-term contracts on the system and allowed us to collect our revenue requirement and incentive earnings for the system over the past two years. In November, the National Energy Board (NEB) approved the settlement reached with our largest Mainline shippers – local natural gas distribution companies in Ontario and Québec – that sets the stage for long-term stability and new expansions on the eastern end of the system.

Over the course of the year, we placed $3.8 billion of new assets into service. In January, the Gulf Coast extension of the Keystone Pipeline System began commercial service, delivering crude oil from the market hub at Cushing, Oklahoma to refineries in Port Arthur, Texas. That was followed by $300 million of expansions on our NGTL System beginning operation and the completion of the US$600-million Tamazunchale Extension project in Mexico. We also took possession of another four solar generation facilities in Ontario as they began producing emission-free electricity under 20-year contracts with the Independent Electricity System Operator (IESO), bringing our total solar capacity to 76 MW, enough to power more than 12,000 homes.

To support the funding of our capital program, we progressed our plans to sell our remaining U.S. natural gas pipelines to our master limited partnership, TC PipeLines, LP. In October, we sold our remaining 30 per cent interest in the Bison Pipeline and in November announced our intention to drop down our remaining 30 per cent interest in the GTN Pipeline. We believe our master limited partnership has the capacity to complete more than US$1 billion per year in asset purchases, and we are committed to vending in our remaining U.S. natural gas pipeline assets over the next several years in order to help fund our ambitious capital growth plan.

Capital Growth Plan

Our $46 billion growth plan includes approximately $12 billion in small to medium-sized projects through 2017 and approximately $34 billion in commercially secured medium to large-scale projects for completion by the end of the decade.



Advancing New Projects

Notable progress was made in 2014 on our portfolio of commercially secured growth projects, which now totals $46 billion including $12 billion in small to medium-sized projects that are expected to drive earnings and cash flow growth as they come on stream through 2017. Our business development teams captured approximately $7 billion in new pipeline opportunities throughout the year, while our project management groups advanced several key projects through the permitting phases and into construction.

Our $34-billion portfolio of large-scale projects moved forward with important stakeholder engagement work and advancements in their respective regulatory processes. More than 18 months of field work and discussion with Aboriginal groups, landowners, communities and governments culminated in filing the application for the $12-billion Energy East Pipeline project with the NEB in October. In British Columbia, extensive environmental assessment and public consultation work resulted in both the Coastal GasLink and Prince Rupert Gas Transmission projects receiving environmental certifications.

Despite our best efforts to obtain a Presidential Permit, the Keystone XL Pipeline project moved into its seventh year of regulatory review in 2014. This delay has increased the cost of the project to approximately US$8 billion but TransCanada and our shippers remain firmly committed to building the pipeline and appreciate the support of the majority of Americans who also believe it is in the nation's best interest.

The Right People

Renewal and development of our people is critical to achieving our goals and is a continuing process. At the heart of TransCanada's competitive advantage are our 6,000 employees and we owe our success to the fact that we have a highly talented and diverse workforce. The board and senior management are confident in our employees' experience and expertise to deliver on our growth plans and commitment to being operationally excellent in everything they do. Our goal is to maintain the high quality of our work by instilling decades of valuable knowledge in our younger leaders and embedding our foundational values of Integrity, Responsibility, Collaboration and Innovation in all of our employees.

Change is also underway on our Board of Directors, where we have had six retirements since early 2012. Most recently, Thomas Stephens retired in the spring of 2014 after many years of service to shareholders. Siim Vanaselja joined last year, bringing extensive financial, governance, management and risk experience, and has proven to be an invaluable addition to the board. We are pleased to report that two of our more experienced directors, Paule Gauthier and Derek Burney, have agreed to stand for nomination for one more year in spite of having reached the usual retirement age. Their continued guidance and contributions in their areas of personal expertise have been critical as we move our $46-billion capital program forward.

We would like to take this opportunity to thank all our employees and shareholders for continuing to support TransCanada. 2014 was a year of major progress for us and we have very ambitious plans to continue to grow your company. We have the assets, opportunity and people to make those plans a reality. As we grow, we will continue to provide the safe, reliable energy that millions of families across North America rely on every day – and for many decades to come. We are committed to continuing to generate significant shareholder returns for those who have placed their confidence in our ability to deliver results.



Russ Girling
President & Chief
Executive Officer

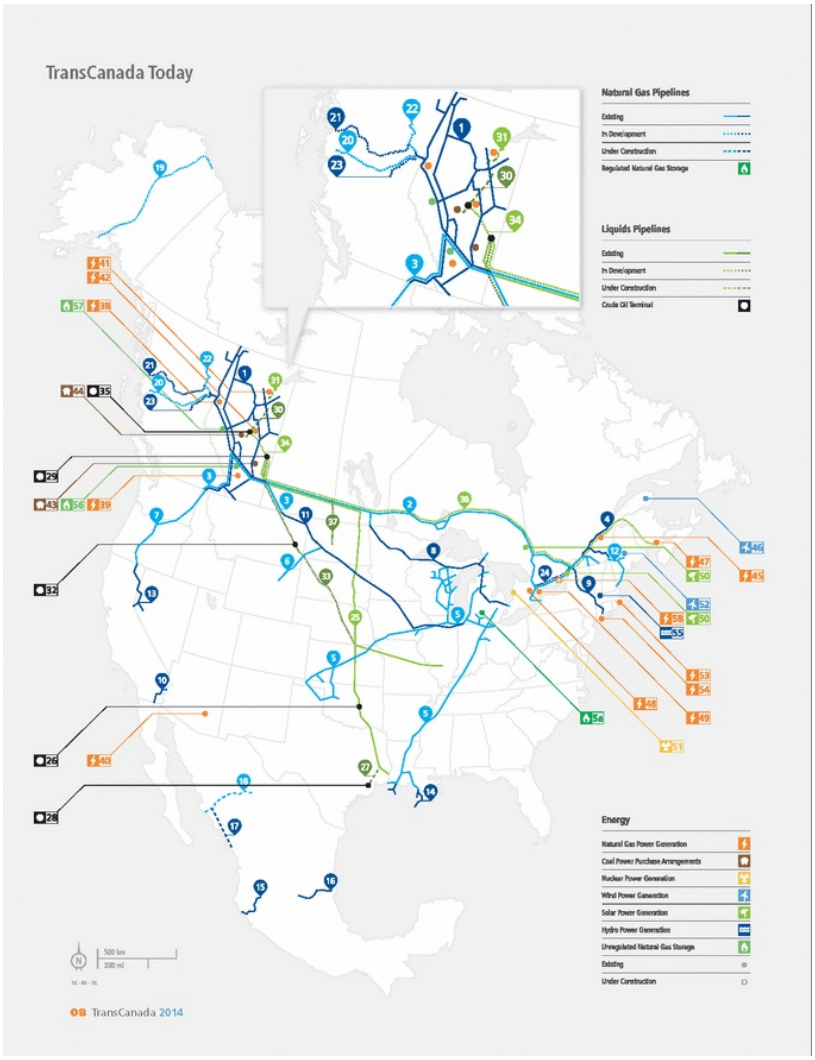


Barry Jackson
Chair of
the Board

A Recognized Leader:

TransCanada aims to be on the industry's leading edge of corporate social responsibility and sustainable practices. In 2014, our dedication did not go unnoticed:

- Received a score at the 88th percentile on the Dow Jones Sustainability Index, and earned rankings on the DJSI North America and World indices.
- Awarded a top score for our actions to disclose carbon emissions and our strategy to mitigate the business risks of climate change with the CDP (formerly the Carbon Disclosure Project).
- Landed a spot on Canada's Top 100 Corporate R&D Spenders list by Research Infosource Inc., Canada's source of R&D intelligence.
- Shortlisted for best overall governance by the Canadian Society of Corporate Secretaries and consistently ranked in the top 10 per cent by other governance assessments.
- Received the Governance, Risk Management and Compliance (GRC) 20/20 Value Award, an acknowledgment for excellence in adapting financial audit software to improving internal project processes.


TransCanada Today
Natural Gas Pipelines
Existing
In Development
Under Construction
Regulated Natural Gas Storage
Liquids Pipelines
Existing
In Development
Under Construction
Crude Oil Terminal
Energy
Natural Gas Power Generation
Coal Power Purchase Arrangements
Nuclear Power Generation
Wind Power Generation
Solar Power Generation
Hydro Power Generation
Unregulated Natural Gas Storage
Existing
Under Construction
500 km
200 mi
08 TransCanada 2014

Natural Gas Pipelines

Canadian Pipelines

1 NGTL System
2 Canadian Mainline
3 Foothills
4 Trans Québec & Maritimes (TQM)

U.S. Pipelines

5 ANR Pipeline
5a ANR Regulated Natural Gas Storage
6 Bison
7 Gas Transmission Northwest (GTN)
8 Great Lakes
9 Iroquois
10 North Baja
11 Northern Border
12 Portland
13 Tuscarora
14 TC Offshore

Mexican Pipelines

15 Guadalajara
16 Tamazunchale

Under Construction

17 Mazatlan Pipeline
18 Topolobampo Pipeline

In Development

19 Alaska LNG Pipeline
20 Coastal GasLink
21 Prince Rupert Gas Transmission
22 North Montney Mainline
23 Merrick Mainline
24 Eastern Mainline

Liquids Pipelines

Canadian / U.S. Pipelines

25 Keystone Pipeline System
26 Cushing Marketlink

Under Construction

27 Houston Lateral
28 Houston Terminal
29 Keystone Hardisty Terminal
30 Grand Rapids Pipeline
31 Northern Courier Pipeline

In Development

32 Bakken Marketlink
33 Keystone XL
34 Heartland Pipeline
35 TC Terminals
36 Energy East Pipeline
37 Upland Pipeline

Energy

Canadian - Western Power

38 Bear Creek
39 Carseland
40 Coolidge[1]
41 Mackay River
42 Redwater
43 Sheerness PPA
44 Sundance A PPA
44 Sundance B PPA

Canadian - Eastern Power

45 Bécancour
46 Cartier Wind
47 Grandview
48 Halton Hills
49 Portlands Energy
50 Ontario Solar (8 Facilities)

Bruce Power

51 Bruce A
51 Bruce B

U.S. Power

52 Kibby Wind
53 Ocean State Power
54 Ravenswood
55 TC Hydro

Unregulated Natural Gas Storage

56 CrossAlta
57 Edson

Under Construction

58 Napanee

[1] Located in Arizona, results reported in Canadian - Western Power

strategy and competitive advantage

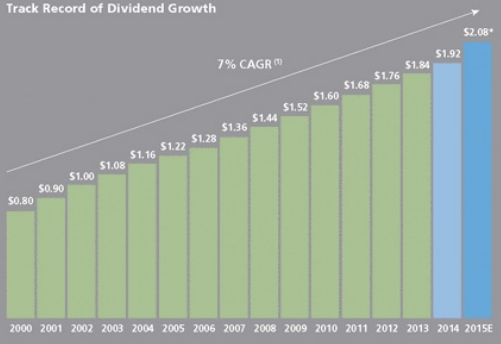
Over the past 15 years we have chosen to focus on three lines of business, giving us both investment diversity and important geographic overlap that has resulted in shared technical, stakeholder and operating expertise in each of our core markets. This has also allowed us to realize material efficiencies in terms of operating costs and financial synergies.

With $46 billion in commercially secured capital projects planned from now until the end of the decade, we are aiming to transform the company by nearly doubling the asset base to more than $90 billion by 2020. Virtually all of the revenue streams from these facilities are secured by long-term contracts or regulated cost-of-service business models, a prudent approach that positions us to weather the uncertainties of market cycles over the long-term.

Sticking to our strategy has paid off. Since 2000, our common shares have provided a 15 per cent average annual total shareholder return. A stable and growing dividend has contributed to this performance. The Board of Directors has raised the dividend every year, from $0.80 per share in 2000 to $2.08 in 2015. Looking forward, the stage has been set for unprecedented growth that will enable TransCanada to become North America's pre-eminent energy infrastructure company and deliver superior total returns to our shareholders.

Our existing operations provide a solid foundation to help fund our capital program and underpin dividend growth going forward. Incremental contributions from $3.8 billion of assets we placed into service helped increase earnings and cash flow in 2014. Over the next three years, we have $12 billion in small to medium-sized growth projects that are expected to generate predictable growth in earnings, cash flow and dividends.

Track Record of Dividend Growth



* Annualized based on first quarter declaration
(1) Compound Annual Growth Rate

TransCanada's occupational and facility safety records continue to be among the best in the industry.

TransCanada invests more than $1 billion every year in proactive maintenance and integrity programs to ensure our assets operate safely and reliably.

TransCanada's pipelines are monitored around the clock in our Operation Control Centres by highly-trained operators using the most sophisticated equipment available.



Zero is real

NO SAFETY INCIDENTS ARE ACCEPTABLE. OUR GOAL OF ZERO INCIDENTS IS REAL AND WE WILL NOT BE SATISFIED UNTIL WE **ACHIEVE IT.**





large photo:
Practice is important. We conducted more than 100 emergency response exercises across North America in 2014 to ensure our employees, contractors and community partners are prepared in the unlikely event of a safety incident at our facilities.

Maximizing the value of our pipelines and power facilities means ensuring they are designed, constructed and operated safely and reliably every day. Our company's priority is to make sure that our employees and contractors make it home safe and that our neighbours see us as a responsible and trusted member of the community.

Our goal is simple: Deliver world-class projects and operations by consistently achieving the right results, the right way. Realizing this goal as we grow requires us to consider the entire life cycle of our assets in a disciplined and organized way, embedding a culture of safety and quality in everything we do. It also requires us to set aggressive performance targets and hold ourselves accountable for achieving consistent and repeatable results for safety, quality, reliability and compliance. That's why we have implemented a number of new programs and business processes that are designed not just to improve our own performance, but to improve our industry as a whole.

Our occupational and facility safety records continue to be among the best in the industry, but we recognize that no safety-related incidents are acceptable. We will not be satisfied until we reach our ultimate goal of zero incidents. That is why we will invest more than $1.5 billion in 2015 on integrity programs and preventative maintenance for our assets and continue to play a leadership role in key initiatives to continually improve the quality of construction across our industry. We are also at the forefront in adopting new technologies to enhance the safety and efficiency of our construction and operations, dedicating more than $80 million over the last five years towards research and development work with industry and government partners.

reliability



focus on safety

TransCanada has become a partner of choice for the large-scale energy infrastructure North America requires because of our strength and expertise in stakeholder relations, engineering, project management and operational excellence.



13 years

FOR THE **13TH YEAR IN A ROW**, WE WERE INCLUDED IN THE **DOW JONES SUSTAINABILITY** WORLD INDEX.



trust



committed to responsible development



Stakeholder engagement on the Energy East Pipeline project has included more than 100 public open houses and extensive consultation with more than 7,000 community members, 5,500 landowners and 155 First Nations and Métis communities across six provinces.

We know that completing $46 billion in capital projects will not be easy, as new energy projects are faced with rising stakeholder expectations and greater public scrutiny than ever before. The standards for developing pipelines, power generation facilities and other critical energy infrastructure have never been higher. But we are up for the challenge of raising the bar on our performance and setting the highest standards for our industry as we bring our plans to life on time and on budget.

At TransCanada, we are committed to protecting the environment, not just because we have to, but because we want to. It's about doing what's right.

Significant Milestones Achieved

We achieved significant milestones on many of these projects in 2014, including filing the application for the Energy East Pipeline project with the NEB. The Energy East application is the most comprehensive regulatory application in our company's history and was the result of more than 18 months of planning, fieldwork and stakeholder engagement that involved extensive consultation with more than 7,000 community members, 5,500 landowners and 155 First Nations and Métis communities across six provinces. Our natural gas pipeline projects in British Columbia made tremendous progress with environmental assessment work, stakeholder engagement and Aboriginal consultation that led to both projects receiving Environmental Assessment Certificates in late 2014. And we began construction on several of our new Alberta crude oil pipeline and terminal facilities after receiving approval from the Alberta Energy Regulator.

World-class operations, a deep commitment to safety and doing the right thing when it comes to dealing with the thousands of landowners, Aboriginal groups, community leaders, local businesses and stakeholders we interact with are critical to our success. We demonstrate these qualities every day as we safely deliver 20 per cent of the continent's natural gas supply, move one-fifth of Canada's crude oil exports to U.S. markets and generate enough electricity for 11 million homes.

TransCanada is committed to treating landowners with integrity and respect. We work to develop fair, honest relationships and maintain open communication throughout the lifecycle of all our projects.

Focus on Corporate Social Responsibility

Relying on our track record is not enough, however. We have devoted significant resources to identifying the most important issues facing our company and developing more rigorous programs to track our performance and minimize risk. This has led to greater consistency and transparency in our Corporate Social Responsibility (CSR) reporting, which has been recognized by external CSR rating agencies. For the 13th year in a row, we were included in the Dow Jones Sustainability World Index and in 2014 we regained a place on their North America Index. We were also recognized as a leader for disclosing our carbon emissions and our strategy for mitigating the business risks of climate change by the London-based CDP (formerly the Carbon Disclosure Project).

We collaborate with national and local organizations to conserve important habitat, protect species at risk and educate the public about the importance of the environment.

We have operated our assets across North America for decades. Our employees and their families are an active part of the communities where they live and work. That's why we view the important work of building and maintaining long-term relationships as a cornerstone of our business. We work from the ground up by engaging directly with the people who are involved in our projects, listening closely to their needs and concerns and responding with positive solutions. These relationships support public confidence in our business, allowing us to continue providing the energy our society needs while meeting the needs of our customers into the future.

large photo:
This land near David City, Nebraska returned to producing healthy crops in 2010, one year after construction of the Keystone Pipeline.

As one of the continent's largest natural gas transporters, we will be an essential player in meeting the need for new and improved infrastructure, beginning with $20 billion in commercially secured projects already in development.



20%

WE **SAFELY DELIVER 20 PER CENT** OF ALL **THE NATURAL GAS CONSUMED IN NORTH AMERICA EVERY DAY.**

connect

natural gas pipelines





In 2014, we placed $900 million of new facilities into service on our NGTL System and in Mexico – the two regions that make up the bulk of our short-term growth plan for natural gas pipelines.

Natural gas pipelines continue to be TransCanada's largest business. The enormous shifts that have occurred in North America's natural gas market in recent years have presented opportunities and challenges for our systems, but the transformational changes we've made to our asset base in response to changing supply and demand patterns will ensure our existing pipelines will prosper over the long haul. At the same time, we have also secured significant growth opportunities to connect the abundant natural gas supplies from the continent's shale basins to new and existing markets at home and abroad.

TransCanada operates a network of 68,000 km (42,100 miles) of natural gas pipeline; enough to circle the earth 1.7 times.

Renewed Stability and Growth

The restructuring of the Canadian Mainline's tolling framework has resulted in greater stability and competitiveness for the Mainline system through a settlement we reached with the three major local distribution companies in Ontario and Québec that the NEB approved in late 2014. The settlement will enhance access of northeastern U.S. natural gas production to markets served by TransCanada facilities and provides long-term stability for the Mainline system over the next 15 years. It also facilitates $500 million in new capital projects to add needed capacity in the Eastern Triangle region while ensuring we can recover our system-wide costs. We also moved forward with significant expansion to the southern arm of the Eastern Triangle, filing an NEB application for the $1.5-billion Eastern Mainline project that will add capacity in the Toronto-to-Ottawa corridor to ensure the markets in southern Ontario and Québec continue to have abundant supplies of natural gas into the future. The addition of 245 kilometres (km) of new pipe under the Eastern Mainline project will allow us to convert approximately 3,000 km of Mainline facilities that are not fully contracted to crude oil service for the Energy East Pipeline project. Doing so will help to reduce costs and increase stability for gas shippers, while continuing to ensure that eastern Canadians have the gas supply they need to heat their homes, schools and hospitals.

The future of the ANR Pipeline has been secured through long-term commitments to move natural gas from the Marcellus and Utica regions to key market destinations.

Long-Term Commitments

Similarly, the future of our ANR Pipeline in the United States was enhanced through long-term commitments to move almost two billion cubic feet per day of natural gas from the Marcellus and Utica regions to key market destinations for an average term of 23 years. This included support for a program to reverse the flow on ANR's Southeast Main Line to enable more natural gas to move south to the Gulf Coast, where markets are experiencing a resurgence of demand for industrial use and planned liquefied natural gas (LNG) export terminals. This successful recontracting ensures the ANR Pipeline will be used to its full potential and provides a solid base to explore further expansions to transport growing gas supplies to key North American markets.

TransCanada operates $27 billion of natural gas pipeline assets in Canada, the United States and Mexico. A 235-km (146-mile) extension to the Tamazunchale Pipeline began service in November 2014.

In 2014, we placed $900 million of new facilities into service on our NGTL System and in Mexico, the two regions that make up the bulk of our short-term growth plan for natural gas pipelines. The NGTL System saw $300 million in new assets begin operation, and another $4.8 billion of new investment is expected by the end of 2017. NGTL continues to be the primary gathering system for Alberta and northeastern British Columbia, moving growing production from the Duvernay, Montney and Horn River plays. In Mexico, the US$600-million extension of the Tamazunchale Pipeline over extremely rugged terrain demonstrated our expertise in engineering and project management. Looking forward, the Topolobampo and Mazatlan projects will double our Mexican assets to US$2.6 billion by 2016 and we are competing for more projects as the country shifts towards using more natural gas for electricity generation and industrial growth.

large photo:
TransCanada is North America's third-largest gas storage provider with 368 billion cubic feet capacity.

Further on the horizon, TransCanada is helping to bring British Columbia's plans to develop a West Coast LNG export industry to life. We have been successful in reaching agreements with several First Nations in northern British Columbia and our teams will continue to build relationships and have meaningful discussions with those living along our pipeline routes to ensure they realize long-term benefits from the historic opportunity that LNG development represents for these communities. The Prince Rupert Gas Transmission and Coastal GasLink projects are underpinned by leading international energy companies that have yet to make final investment decisions on their respective LNG developments. Both projects are expected to be in service by the end of the decade.

Liquids pipelines are the largest pillar of TransCanada's growth plan, with $25 billion in new projects underpinned by long-term contracts in development for completion by the end of the decade.



1/5

THE **KEYSTONE PIPELINE SYSTEM** TRANSPORTS **ONE-FIFTH** OF **CANADA'S CRUDE OIL EXPORTS TO THE UNITED STATES.**





deliver



liquids pipelines

Our history of operating natural gas and liquids pipelines in Alberta has been instrumental in capturing $3.6 billion in new investments to move growing crude oil production in the province.

We are developing an enviable position in the liquid hydrocarbon transportation business as we move forward with our strategy of connecting key producing areas in Canada and the United States to domestic and international refinery markets. Our Keystone Pipeline System is proving to be a valuable platform for growth, while our experience in repurposing underutilized natural gas pipeline facilities is helping to meet the growing need for crude oil transportation across the continent.

Construction is underway on the US$600 million Houston Lateral and Terminal project in Texas, employing members of local tribes to monitor for unanticipated sites of cultural significance.

EBITDA Surpasses $1 Billion

Keystone has safely transported more than 830 million barrels of crude oil from Canada to U.S. markets since it began operation in July 2010. With the completion of the Gulf Coast extension in January 2014, the system now provides a direct route for our shippers from Hardisty, Alberta to Gulf Coast refineries at Port Arthur, Texas. This resulted in the EBITDA contribution from Keystone surpassing $1 billion in 2014. Our Keystone Pipeline System will extend its market reach even further in 2015 with the completion of the Houston Lateral and Terminal project.

Our history of operating natural gas and liquids pipelines in Alberta has been instrumental in capturing $3.6 billion in new investments to move growing crude oil production within the province. These projects will serve as an excellent base for our shippers to access various crude oil markets via Keystone and our proposed Keystone XL and Energy East projects. Construction commenced in the second half of 2014 on both the $1.5-billion Grand Rapids Pipeline and on the $900-million Northern Courier Pipeline following approval of both projects by the Alberta Energy Regulator.

Committed to Keystone XL

Listening to communities: The application for the Energy East Pipeline project reflected the input of thousands of landowners, Aboriginal groups and community members across six provinces.

TransCanada and our shippers remain committed to Keystone XL despite the unprecedented delays we have faced on this much-needed project. We are pleased that the Final Supplemental Environmental Impact Statement issued by the Department of State at the end of January 2014 reinforced previous conclusions that Keystone XL will be built and operated with minimal impact on the environment. The report also reiterated the benefits of the project, noting that Keystone XL will enhance American energy security, create more than 40,000 jobs and generate billions of dollars in economic activity for the U.S. The Nebraska Supreme Court's decision in early 2015 validated the pipeline's route in the state, allowing the Department of State to complete its National Interest Determination process. We expect Keystone XL to begin service approximately two years after receiving a Presidential Permit that will allow the pipeline to cross the Canada-U.S. border.

Energy East Moves Forward

The Gulf Coast extension of the Keystone System provides a direct route for our shippers from Hardisty, Alberta to U.S. Gulf Coast refineries at Port Arthur, Texas.

Our $12-billion Energy East Pipeline project has secured long-term take-or-pay contracts to ship approximately one million barrels per day of crude oil from western Canada to refineries and proposed marine terminals in eastern Canada. This innovative project that will repurpose more than 3,000 km of underutilized capacity on the Canadian Mainline continues to gain public support as Canadians recognize the benefits of enhancing market access for our valuable energy resources and eliminating eastern Canada's reliance on imported crude oil.

large photo:
The hub of TransCanada's liquids network is the Hardisty terminal in Alberta.

We filed an extensive application for the Energy East Pipeline project with the NEB at the end of October. Subject to regulatory approvals, we anticipate crude oil deliveries to begin by the end of 2018.

Altogether, our list of commercially secured projects will transform the company. In addition to smaller-scale projects, bringing Keystone XL and Energy East to fruition will provide us with approximately 2.5 million barrels per day of long-haul capacity underpinned by approximately two million barrels per day of long-term contracts, establishing us as leaders in the transportation of liquid hydrocarbons.

We have critical mass in our core North American power markets and are well positioned to capture opportunities in the future.



11MM homes

TRANSCANADA OWNS OR HAS INTEREST IN **10,900 MEGAWATTS OF ELECTRICITY GENERATION** ACROSS NORTH AMERICA, ENOUGH TO **POWER** APPROXIMATELY **11 MILLION HOMES.**







Our Energy business performed well in 2014, generating more than $1.3 billion in EBITDA thanks to the strong performance of the Bruce Nuclear facility in Ontario and our U.S.-based fleet of power generation facilities.

We are Canada's largest private sector power company, with interests in 10,900 MW of generating capacity, one-third of which comes from emission-less sources including nuclear, hydro, wind and solar. Our diverse portfolio of assets is comprised of 19 power generation facilities that are either underpinned by long-term contracts, are on the low end of the cost curve, or are otherwise supported by stable revenue streams. With facilities located in Alberta, eastern Canada, New England, Arizona and New York, our focus on maximizing earnings from this critical infrastructure is relentless. Our experience in these regions positions us well for the future, as new opportunities arise to keep pace with demand growth in these markets through the replacement of older facilities with new, less carbon-intense forms of electricity generation.

The Bruce Nuclear facility in Ontario produces approximately one-third of the province's power supply.

Strong Performance

Our Energy business performed well in 2014, generating more than $1.3 billion in EBITDA. Strong performance of the Bruce Nuclear facility in Ontario, where all eight reactors are in operation and providing approximately one-third of the province's power supply, was coupled with similarly strong performance from our U.S.-based fleet. We also expanded our portfolio of renewable energy sources with four additional solar generation facilities in Ontario.

The $1-billion Napanee Generating Station under development in Ontario obtained necessary permits for construction to commence in January 2015. This highly efficient, combined-cycle natural-gas-fired power plant will be located in the town of Greater Napanee and will be capable of generating 900 MW under a 20-year clean energy supply contract with the IESO.

Growth Opportunities

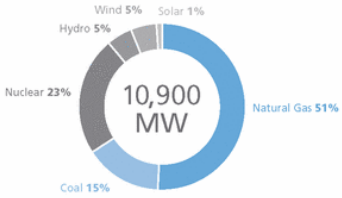
Located in Queens, NY, the Ravenswood Generating Station is capable of providing more than 20 per cent of New York City's electricity.

Alberta continues to be an attractive area for long-term investment with growing demand for power and more than 800 MW of coal-fired generation expected to come offline around the end of the decade as a portion of the coal fleet reaches the end of its useful life. We believe this will present opportunities to add new and replacement capacity in the latter half of the decade.

We will continue to explore further opportunities for growth in markets where we have an established presence and a competitive advantage, either through development or acquisition. This includes consideration of further nuclear refurbishments in Ontario, capacity additions or replacements in the northeastern U.S. markets and consideration of new power generation facilities in Mexico where we have an established and growing corporate presence as this market continues to mature and evolve.

TransCanada operates eight solar generating facilities in Ontario, supplying renewable power under a long-term contract.

large photo: TransCanada has invested more than $5 billion in emission-less energy assets, including the Kibby wind facility in Maine.



Fuel Sources

One-third of the power we generate comes from emission-less sources.

executive
leadership team



Kristine Delkus
Executive Vice-President and General Counsel

Karl Johannson
Executive Vice-President and President, Natural Gas Pipelines

Russ Girling
President and Chief Executive Officer

Wendy Hanrahan
Executive Vice-President, Corporate Services

Bill Taylor
Executive Vice-President and President, Energy

Alex Pourbaix
Executive Vice-President and President, Development

Jim Baggs
Executive Vice-President, Operations and Engineering

Paul Miller
Executive Vice-President and President, Liquids Pipelines

Don Marchand
Executive Vice-President and Chief Financial Officer

A strong balance sheet provides the financial strength and flexibility to execute our ambitious growth plan.

positioned for success

All the conditions are in place for TransCanada to generate significant value and shareholder returns in the years ahead. We have an enduring business strategy that has a proven track record over the past 15 years. We will remain focused on maximizing the value of our existing assets and executing on our $46-billion portfolio of commercially secured growth projects. And we will continue to pursue the low-risk organic growth opportunities generated from our expanding asset base across North America.

Our strong balance sheet and credit ratings provide the financial flexibility to execute our ambitious growth plan, take advantage of new opportunities when and where they make sense and allow us to access significant capital on compelling terms at all points of the economic cycle. We will continue to evaluate funding alternatives and portfolio management to enhance shareholder returns, including following through on our commitment to sell our remaining U.S. natural gas pipeline assets to our master limited partnership, TC PipeLines, LP.

Our goal is to maximize long-term shareholder value, with an unwavering focus on per-share performance. As we advance our portfolio of commercially secured capital growth projects through the end of the decade we expect to generate significant sustainable growth in earnings, cash flow and dividends.

Management's discussion and analysis

February 12, 2015

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TransCanada Corporation. It discusses our business, operations, financial position, risks and other factors for the year ended December 31, 2014.

This MD&A should be read with our accompanying December 31, 2014 audited comparative consolidated financial statements and notes for the same period, which have been prepared in accordance with U.S. generally accepted accounting principles (GAAP).

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GLOSSARY **120**

About this document

Throughout this MD&A, the terms, *we*, *us*, *our* and *TransCanada* mean TransCanada Corporation and its subsidiaries.

Abbreviations and acronyms that are not defined in the document are defined in the glossary on page 120.

All information is as of February 12, 2015 and all amounts are in Canadian dollars, unless noted otherwise.

FORWARD-LOOKING INFORMATION

We disclose forward-looking information to help current and potential investors understand management's assessment of our future plans and financial outlook, and our future prospects overall.

Statements that are *forward-looking* are based on certain assumptions and on what we know and expect today and generally include words like *anticipate*, *expect*, *believe*, *may*, *will*, *should*, *estimate* or other similar words.

Forward-looking statements in this MD&A may include information about the following, among other things:

- anticipated business prospects
- our financial and operational performance, including the performance of our subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows and future financing options available to us
- expected costs for planned projects, including projects under construction and in development
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes
- expected impact of regulatory outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future accounting changes, commitments and contingent liabilities
- expected industry, market and economic conditions.

Forward-looking statements do not guarantee future performance. Actual events and results could be significantly different because of assumptions, risks or uncertainties related to our business or events that happen after the date of this MD&A.

Our forward-looking information is based on the following key assumptions, and subject to the following risks and uncertainties:

Assumptions

- inflation rates, commodity prices and capacity prices
- timing of financings and hedging
- regulatory decisions and outcomes
- foreign exchange rates
- interest rates
- tax rates
- planned and unplanned outages and the use of our pipeline and energy assets
- integrity and reliability of our assets
- access to capital markets
- anticipated construction costs, schedules and completion dates
- acquisitions and divestitures.

Risks and uncertainties

- our ability to successfully implement our strategic initiatives
- whether our strategic initiatives will yield the expected benefits
- the operating performance of our pipeline and energy assets
- amount of capacity sold and rates achieved in our pipelines business
- the availability and price of energy commodities
- the amount of capacity payments and revenues we receive from our energy business
- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration and insurance claims
- performance of our counterparties
- changes in market commodity prices
- changes in the political environment
- changes in environmental and other laws and regulations
- competitive factors in the pipeline and energy sectors
- construction and completion of capital projects
- costs for labour, equipment and materials
- access to capital markets
- interest and foreign exchange rates
- weather
- cyber security
- technological developments
- economic conditions in North America as well as globally.

You can read more about these factors and others in reports we have filed with Canadian securities regulators and the U.S. Securities and Exchange Commission (SEC).

As actual results could vary significantly from the forward-looking information, you should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events, unless we are required to by law.

FOR MORE INFORMATION

See Supplementary information beginning on page 183 for other consolidated financial information on TransCanada for the last five years.

You can also find more information about TransCanada in our annual information form and other disclosure documents, which are available on SEDAR (www.sedar.com).

NON-GAAP MEASURES

We use the following non-GAAP measures:

- EBITDA
- EBIT
- funds generated from operations
- comparable earnings
- comparable earnings per common share
- comparable EBITDA
- comparable EBIT
- comparable depreciation and amortization
- comparable interest expense
- comparable interest income and other
- comparable income tax expense.

These measures do not have any standardized meaning as prescribed by U.S. GAAP and therefore may not be similar to measures presented by other entities.

EBITDA and EBIT

We use EBITDA as an approximate measure of our pre-tax operating cash flow. It measures our earnings before deducting financial charges, income tax, depreciation and amortization, net income attributable to non-controlling interests and preferred share dividends, and includes income from equity investments. EBIT measures our earnings from ongoing operations and is a useful measure of our performance and an effective tool for evaluating trends in each segment as it is equivalent to our segmented earnings.

Funds generated from operations

Funds generated from operations includes net cash provided by operations before changes in operating working capital. We believe it is a useful measure of our consolidated operating cash flow because it does not include fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period and is used to provide a consistent measure of the cash generating performance of our assets. See the Financial condition section for a reconciliation to net cash provided by operations.

Comparable measures

We calculate the comparable measures by adjusting certain GAAP and non-GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period. These comparable measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable.

Comparable measure	Original measure
comparable earnings	net income attributable to common shares
comparable earnings per common share	net income per common share
comparable EBITDA	EBITDA
comparable EBIT	segmented earnings
comparable depreciation and amortization	depreciation and amortization
comparable interest expense	interest expense
comparable interest income and other	interest income and other
comparable income tax expense	income tax expense

Our decision not to include a specific item is subjective and made after careful consideration. Specific items may include:

- certain fair value adjustments relating to risk management activities
- income tax refunds and adjustments
- gains or losses on sales of assets
- legal, contractual and bankruptcy settlements
- impact of regulatory or arbitration decisions relating to prior year earnings
- write-downs of assets and investments.

We calculate comparable earnings by excluding the unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives provide effective economic hedges, but do not meet the criteria for hedge accounting. As a result, the changes in fair value are recorded in net income. As these unrealized changes in fair value do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them part of our underlying operations.

About our business

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

THREE CORE BUSINESSES

We operate our business in three segments – Natural Gas Pipelines, Liquids Pipelines and Energy. We also have a non-operational corporate segment consisting of corporate and administrative functions that provide support and governance to our operational business segments.

Our $59 billion portfolio of energy infrastructure assets meets the needs of people who rely on us to deliver their energy safely and reliably every day. We operate in seven Canadian provinces, 35 U.S. states and Mexico.

Natural Gas Pipelines

Canadian Pipelines

1 NGTL System
2 Canadian Mainline
3 Foothills
4 Trans Québec & Maritimes (TQM)

U.S. Pipelines

5 ANR Pipeline
5a ANR Regulated Natural Gas Storage
6 Bison
7 Gas Transmission Northwest (GTN)
8 Great Lakes
9 Iroquois
10 North Baja
11 Northern Border
12 Portland
13 Tuscarora
14 TC Offshore

Mexican Pipelines

15 Guadalajara
16 Tamazunchale

Under Construction

17 Mazatlan Pipeline
18 Topolobampo Pipeline

In Development

19 Alaska LNG Pipeline
20 Coastal GasLink
21 Prince Rupert Gas Transmission
22 North Montney Mainline
23 Merrick Mainline
24 Eastern Mainline

Liquids Pipelines

Canadian / U.S. Pipelines

25 Keystone Pipeline System
26 Cushing Marketlink

Under Construction

27 Houston Lateral
28 Houston Terminal
29 Keystone Hardisty Terminal
30 Grand Rapids Pipeline
31 Northern Courier Pipeline

In Development

32 Bakken Marketlink
33 Keystone XL
34 Heartland Pipeline
35 TC Terminals
36 Energy East Pipeline
37 Upland Pipeline

Energy

Canadian - Western Power

38 Bear Creek
39 Carseland
40 Coolidge[1]
41 Mackay River
42 Redwater
43 Sheerness PPA
44 Sundance A PPA
44 Sundance B PPA

Canadian - Eastern Power

45 Bécancour
46 Cartier Wind
47 Grandview
48 Halton Hills
49 Portlands Energy
50 Ontario Solar (8 Facilities)

Bruce Power

51 Bruce A
51 Bruce B

U.S. Power

52 Kibby Wind
53 Ocean State Power
54 Ravenswood
55 TC Hydro

Unregulated Natural Gas Storage

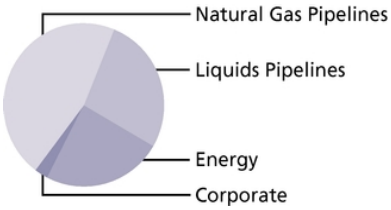
56 CrossAlta
57 Edson

Under Construction

58 Napanee

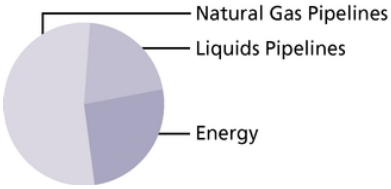
[1] Located in Arizona, results reported in Canadian - Western Power

at December 31 (millions of $)	2014	2013
Total assets		
Natural Gas Pipelines	**27,103**	25,165
Liquids Pipelines	**16,116**	13,253
Energy	**14,197**	13,747
Corporate	**1,531**	1,733
	58,947	53,898



year ended December 31 (millions of $)	2014	2013
Total revenue		
Natural Gas Pipelines	**4,913**	4,497
Liquids Pipelines	**1,547**	1,124
Energy	**3,725**	3,176
	10,185	8,797

year ended December 31 (millions of $)	2014	2013
Segmented earnings		
Natural Gas Pipelines	**2,187**	1,881
Liquids Pipelines	**843**	603
Energy	**1,051**	1,113
Corporate	**(150)**	(124)
	3,931	3,473



Common share price
at December 31



Common shares outstanding – average

(millions)	
2014	708
2013	707
2012	705

as at February 9, 2015 Common shares	Issued and outstanding
	709 million

Preferred shares	Issued and outstanding	Convertible to
Series 1	9.5 million	Series 2 preferred shares
Series 2	12.5 million	Series 1 preferred shares
Series 3	14 million	Series 4 preferred shares
Series 5	14 million	Series 6 preferred shares
Series 7	24 million	Series 8 preferred shares
Series 9	18 million	Series 10 preferred shares

Options to buy common shares	Outstanding	Exercisable
	8 million	5 million

OUR STRATEGY

Our energy infrastructure business is made up of pipeline and power generation assets that gather, transport, produce, store or deliver natural gas, crude oil and other petroleum products and electricity to support businesses and communities in North America.

Our vision is to be the leading energy infrastructure company in North America, focusing on pipeline and power generation opportunities in regions where we have or can develop a significant competitive advantage.

Key components of our strategy

1 **Maximize the full-life value of our infrastructure assets and commercial positions**

Our strategy at a glance

- Long-life infrastructure assets and long-term commercial arrangements are the cornerstones of our low-risk business model.
- Our 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, long-term power sale agreements and shorter-term power sales to wholesale and load customers are used to manage and optimize our portfolio and to manage price volatility.

2 **Commercially develop and build new asset investment programs**

Our strategy at a glance

- We are developing high quality, long-life projects under our current $46 billion capital program, comprised of $12 billion in short-term projects and $34 billion in medium to long-term projects. These will contribute incremental earnings over the near, medium and long terms as our investments are placed in service.
- Our expertise in managing construction risks and maximizing capital productivity ensures a disciplined approach to quality, cost and schedule, resulting in superior service for our customers and returns to shareholders.
- As part of our growth strategy, we rely on this experience and our regulatory, commercial, financial, legal and operational expertise to successfully build and integrate new energy and pipeline facilities.
- Our growing investment in natural gas, nuclear, wind, hydro and solar generating facilities demonstrates our commitment to clean, sustainable energy.

3 **Cultivate a focused portfolio of high quality development options**

Our strategy at a glance

- We focus on pipelines and energy growth initiatives in core regions of North America.
- We assess opportunities to acquire and develop energy infrastructure that complements our existing portfolio and provides access to attractive supply and market regions.
- We will advance selected opportunities to full development and construction when market conditions are appropriate and project risks and returns are acceptable.

4 **Maximize our competitive strengths**

Our strategy at a glance

- We are continually developing competitive strengths to ensure we provide maximum shareholder value over the short, medium and long terms.

A competitive advantage

Years of experience in the energy infrastructure business and a disciplined approach to project and operational management and capital investment give us our competitive edge.

- Strong leadership: scale, presence, operating capabilities and strategy development; expertise in regulatory, legal, commercial and financing support.
- High quality portfolio: a low-risk business model that maximizes the full-life value of our long-life assets and commercial positions.
- Disciplined operations: highly skilled in designing, building and operating energy infrastructure; focus on operational excellence; and a commitment to health, safety and the environment are paramount parts of our core values.
- Financial positioning: excellent reputation for consistent financial performance and long-term financial stability and profitability; disciplined approach to capital investment; ability to access sizable amounts of competitively priced capital to support our growth; stable and growing master limited partnership that complements our funding program; ability to balance an increasing dividend on our common shares while preserving financial flexibility to fund industry-leading capital program in all market conditions.
- Long-term relationships: long-term, transparent relationships with key customers and stakeholders; clear communication of our value to equity and debt investors – both the upside and the risks – to build trust and support.

CAPITAL PROGRAM

We are developing quality projects under our long-term capital program. These long-life infrastructure assets are supported by long-term commercial arrangements with creditworthy counterparties or regulated business models and are expected to generate significant growth in earnings and cash flow.

Our capital program consists of $12 billion of small to medium-sized, shorter-term projects and $34 billion of commercially secured large-scale, medium and longer-term projects. Amounts presented exclude the impact of foreign exchange and capitalized interest.

All projects are subject to cost adjustments due to market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits.

at December 31, 2014 (billions of $)	Segment	Expected In-Service Date	Estimated Project Cost	Amount Spent
Small to medium-sized, shorter-term				
Houston Lateral and Terminal	Liquids Pipelines	2015	US 0.6	US 0.4
Topolobampo	Natural Gas Pipelines	2016	US 1.0	US 0.7
Mazatlan	Natural Gas Pipelines	2016	US 0.4	US 0.2
Grand Rapids[1]	Liquids Pipelines	2016-2017	1.5	0.2
Heartland and TC Terminals	Liquids Pipelines	2017	0.9	0.1
Northern Courier	Liquids Pipelines	2017	0.9	0.2
Canadian Mainline – Other	Natural Gas Pipelines	2015-2016	0.5	-
NGTL System – North Montney	Natural Gas Pipelines	2016-2017	1.7	0.1
– 2016/17 Facilities	Natural Gas Pipelines	2016-2017	2.7	-
– Other	Natural Gas Pipelines	2015-2016	0.4	0.1
Napanee	Energy	2017 or 2018	1.0	0.1
			11.6	2.1
Large-scale, medium and longer-term				
Upland	Liquids Pipelines	2018	0.6	-
Keystone projects				
Keystone XL[2]	Liquids Pipelines	[3]	US 8.0	US 2.4
Keystone Hardisty Terminal	Liquids Pipelines	[3]	0.3	0.1
Energy East projects				
Energy East[4]	Liquids Pipelines	2018	12.0	0.5
Eastern Mainline	Natural Gas Pipelines	2017	1.5	-
BC west coast LNG-related projects				
Coastal GasLink	Natural Gas Pipelines	2019+	4.8	0.2
Prince Rupert Gas Transmission	Natural Gas Pipelines	2019+	5.0	0.3
NGTL System – Merrick	Natural Gas Pipelines	2020	1.9	-
			34.1	3.5
			45.7	5.6

1 Represents our 50 per cent share.

2 Estimated project cost dependent on the timing of the Presidential permit.

3 Approximately two years from the date the Keystone XL permit is received.

4 Excludes transfer of Canadian Mainline natural gas assets.

2014 FINANCIAL HIGHLIGHTS

We use certain financial measures that do not have a standardized meaning under GAAP because we believe they improve our ability to compare results between reporting periods and enhance understanding of our operating performance. Known as non-GAAP measures, they may not be similar to measures provided by other companies.

Highlights

Comparable EBITDA (comparable earnings before interest, taxes, depreciation and amortization), comparable EBIT (comparable earnings before interest and taxes), comparable earnings, comparable earnings per common share and funds generated from operations are all non-GAAP measures. See page 24 for more information about the non-GAAP measures we use and page 112 for a reconciliation to their GAAP equivalents.

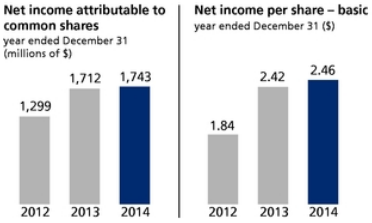
year ended December 31 (millions of $, except per share amounts)	2014	2013	2012
Revenue	**10,185**	8,797	8,007
Net income attributable to common shares	**1,743**	1,712	1,299
per common share – basic & diluted	**$2.46**	$2.42	$1.84
Comparable EBITDA	**5,521**	4,859	4,245
Comparable earnings	**1,715**	1,584	1,330
per common share	**$2.42**	$2.24	$1.89
Operating cash flow			
Funds generated from operations	**4,268**	4,000	3,284
(Increase)/decrease in working capital	**(189)**	(326)	287
Net cash provided by operations	**4,079**	3,674	3,571
Investing activities			
Capital spending – capital expenditures	**3,550**	4,264	2,595
Capital spending – projects under development	**807**	488	3
Equity investments	**256**	163	652
Acquisitions, net of cash acquired	**241**	216	214
Proceeds from sale of assets, net of transaction costs	**196**	-	-
Balance sheet			
Total assets	**58,947**	53,898	48,396
Long-term debt	**24,757**	22,865	18,913
Junior subordinated notes	**1,160**	1,063	994
Preferred shares	**2,255**	1,813	1,224
Non-controlling interests	**1,583**	1,611	1,425
Common shareholders' equity	**16,815**	16,712	15,687
Dividends declared			
per common share	**$1.92**	$1.84	$1.76
per Series 1 preferred share	**$1.15**	$1.15	$1.15
per Series 3 preferred share	**$1.00**	$1.00	$1.00
per Series 5 preferred share	**$1.10**	$1.10	$1.10
per Series 7 preferred share	**$1.00**	$0.91	-
per Series 9 preferred share[1]	**$1.09**	-	-

[1] Issued January 20, 2014.

Consolidated results

year ended December 31 (millions of $, except per share amounts)	2014	2013	2012
Segmented earnings			
Natural Gas Pipelines	**2,187**	1,881	1,808
Liquids Pipelines	**843**	603	553
Energy	**1,051**	1,113	579
Corporate	**(150)**	(124)	(111)
Total segmented earnings	**3,931**	3,473	2,829
Interest expense	**(1,198)**	(985)	(976)
Interest income and other	**91**	34	85
Income before income taxes	**2,824**	2,522	1,938
Income tax expense	**(831)**	(611)	(466)
Net income	**1,993**	1,911	1,472
Net income attributable to non-controlling interests	**(153)**	(125)	(118)
Net income attributable to controlling interests	**1,840**	1,786	1,354
Preferred share dividends	**(97)**	(74)	(55)
Net income attributable to common shares	**1,743**	1,712	1,299
Net income per common share – basic and diluted	**$2.46**	$2.42	$1.84

Net income attributable to common shares



Net income attributable to common shares in 2014 was $1,743 million (2013 – $1,712 million; 2012 – $1,299 million). The following specific items were recognized in net income in 2012 to 2014:

2014

- a gain of $99 million after tax on the sale of Cancarb Limited and its related power generation business
- a net loss of $32 million after tax resulting from a termination payment to Niska Gas Storage for contract restructuring
- a gain of $8 million after tax on the sale of our 30 per cent interest in Gas Pacifico/INNERGY

2013

- net income of $84 million recorded in 2013 related to 2012 from the National Energy Board's (NEB) 2013 decision on the Canadian Restructuring Proposal (NEB 2013 Decision)
- a favourable tax adjustment of $25 million due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax

2012

- an after-tax charge of $15 million related to the Sundance A PPA arbitration decision. This charge was recorded in second quarter 2012 but related to amounts originally recorded in fourth quarter 2011.

The items discussed above were excluded from comparable earnings for the relevant periods. Certain unrealized fair value adjustments relating to risk management activities are also excluded from comparable earnings. The remainder of net income is equivalent to comparable earnings. A reconciliation of net income attributable to common shares to comparable earnings is shown in the following table.

Reconciliation of net income to comparable earnings

year ended December 31 (millions of $, except per share amounts)	2014	2013	2012
Net income attributable to common shares	**1,743**	1,712	1,299
Specific items (net of tax):			
Cancarb gain on sale	**(99)**	-	-
Niska contract termination	**32**	-	-
Gas Pacifico/INNERGY gain on sale	**(8)**	-	-
NEB 2013 Decision – 2012	**-**	(84)	-
Part VI.I income tax adjustment	**-**	(25)	-
Sundance A PPA arbitration decision – 2011	**-**	-	15
Risk management activities[1]	**47**	(19)	16
Comparable earnings	**1,715**	1,584	1,330
Net income per common share	**$2.46**	$2.42	$1.84
Specific items (net of tax):			
Cancarb gain on sale	**(0.14)**	-	-
Niska contract termination	**0.04**	-	-
Gas Pacifico/INNERGY gain on sale	**(0.01)**	-	-
NEB 2013 Decision – 2012	**-**	(0.12)	-
Part VI.I income tax adjustment	**-**	(0.04)	-
Sundance A PPA arbitration decision – 2011	**-**	-	0.02
Risk management activities[1]	**0.07**	(0.02)	0.03
Comparable earnings per share	**$2.42**	$2.24	$1.89

1

year ended December 31 (millions of $)	2014	2013	2012
Canadian Power	**(11)**	(4)	4
U.S. Power	**(55)**	50	(1)
Natural Gas Storage	**13**	(2)	(24)
Foreign exchange	**(21)**	(9)	(1)
Income tax attributable to risk management activities	**27**	(16)	6
Total (losses)/gains from risk management activities	**(47)**	19	(16)

Comparable earnings



Comparable earnings in 2014 were $131 million higher than in 2013, an increase of $0.18 per share.

The increase in comparable earnings was primarily the net result of:

- incremental earnings from the Gulf Coast extension of the Keystone Pipeline System which was placed in service in January 2014
- higher interest expense from debt issuances and lower capitalized interest due to projects placed in service
- lower earnings from Western Power as a result of lower realized power prices
- higher earnings from the Tamazunchale Extension which was placed in service in 2014
- higher earnings from U.S. Natural Gas Pipelines due to higher transportation revenues at Great Lakes reflecting colder winter weather and increased demand, partially offset by lower contributions from GTN and Bison following the reductions in our effective ownership in July 2013 (GTN and Bison) and October 2014 (Bison)
- higher earnings from U.S. Power mainly because of higher realized capacity prices in New York and higher realized power prices for the New York and New England facilities
- higher earnings from the Canadian Mainline due to higher incentive earnings
- incremental earnings from Eastern Power primarily due to solar facilities acquired in 2013 and 2014.

Comparable earnings in 2013 were $254 million higher than 2012, an increase of $0.35 per share.

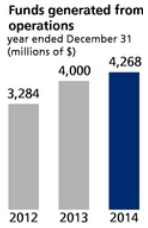
The increase in comparable earnings was the net result of:

- higher equity income from Bruce Power due to incremental earnings from Units 1 and 2 and lower planned outage days at Unit 4
- higher earnings from the Canadian Mainline reflecting the higher rate of return on common equity (ROE) of 11.50 per cent in 2013 compared to 8.08 per cent in 2012 due to the NEB 2013 Decision
- higher earnings from U.S. Power because of higher capacity prices in New York and higher realized power prices
- higher earnings from the NGTL System reflecting a higher investment base and the impact of the 2013-2014 NGTL Settlement approved by the NEB in November 2013
- higher earnings from the Keystone Pipeline System primarily due to higher volumes
- higher earnings from Western Power because of higher purchased volumes under the PPAs
- lower contributions from U.S. Natural Gas Pipelines because of lower earnings at ANR and Great Lakes.

Cash flows

Funds generated from operations

Funds generated from operations were 7 per cent higher this year compared to 2013 primarily for the same reasons comparable earnings were higher, as described above.

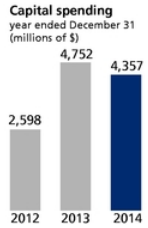


Funds used in investing activities

***Capital spending*[1]**

year ended December 31 (millions of $)	**2014**	2013	2012
Natural Gas Pipelines	**2,136**	2,021	1,389
Liquids Pipelines	**1,969**	2,529	1,148
Energy	**206**	152	24
Corporate	**46**	50	37
	4,357	4,752	2,598

1 Capital spending includes capital expenditures and capital projects under development.



We invested $4.4 billion in capital projects in 2014 as part of our ongoing capital program which was consistent with our revised outlook in our third quarter 2014 report to shareholders. Our capital program is a key part of our strategy to optimize the value of our existing assets and develop new, complementary assets in high demand areas that are expected to generate stable, predictable earnings and cash flows and to maximize returns to shareholders for years to come.

Equity investments and acquisitions

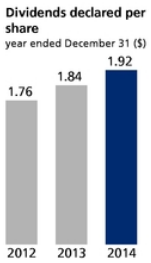
In 2014, we invested $256 million in our equity investments primarily related to the construction of Grand Rapids. We also spent $241 million on the acquisition of four additional solar facilities from Canadian Solar Solutions Inc.

Balance sheet

We continue to maintain a strong balance sheet while growing our total assets by $10.6 billion since 2012. At December 31, 2014, common equity represented 38 per cent (40 per cent in 2013) of our capital structure. See page 91 for more information about our capital structure.

Dividends

We increased the quarterly dividend on our outstanding common shares by eight per cent to $0.52 per share for the quarter ending March 31, 2015 which equates to an annual dividend of $2.08 per share. This is the 15th consecutive year we have increased the dividend on our common shares.



Dividend reinvestment plan

Under our dividend reinvestment plan (DRP), eligible holders of TransCanada common or preferred shares can reinvest their dividends and make optional cash payments to buy additional TransCanada common shares.

Quarterly dividend on our common shares

$0.52 per share (for the quarter ending March 31, 2015)

Annual dividends on our preferred shares

Series 1 $0.82[1]

Series 2 $0.69[2]

Series 3 $1.00

Series 5 $1.10

Series 7 $1.00

Series 9 $1.06

[1] In December 2014, 12.5 million Series 1 preferred shares were converted to Series 2 preferred shares. See the Financial condition section for more information.

[2] Annualized amount of the first quarterly floating rate period as the floating rate will reset each quarter. See the Financial condition section for more information.

Cash dividends

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Common shares	**1,345**	1,285	1,226
Preferred shares	**94**	71	55

Refer to the Results section in each business segment and the Financial condition section of this MD&A for further discussion of these highlights.

OUTLOOK

Earnings

We anticipate earnings in 2015 to be higher than 2014, mainly due to the net effect of the following:

- increase in the average investment base for the NGTL System
- incremental earnings from solar facilities acquired in 2014 and higher contractual earnings at Bécancour
- anticipated higher net margins and production from the U.S. Power assets
- expected earnings associated with increased contracts for ANR
- decline in earnings for the Canadian Mainline as a result of the 2015 – 2030 Tolls and Tariff Application
- reduced equity income from Bruce Power due to increased planned maintenance activity and higher operating costs
- lower Alberta power prices and lower contributions from our Natural Gas Storage operations.

Earnings will also be impacted by additional Corporate segment items including increased AFUDC reflecting continued growth and capital spending primarily on Topolobampo, Mazatlan, the NGTL System and Energy East.

Results from our U.S. businesses are subject to fluctuations in foreign exchange rates. These fluctuations are largely offset by interest on our U.S. dollar denominated debt as well as our hedging activities which are included in our Corporate segment.

Natural Gas Pipelines

Earnings from the Natural Gas Pipelines segment are affected by regulatory decisions and the timing of these decisions. Earnings are also impacted by market conditions, which drive the level of demand and the rate, we secure for our services.

Canadian Mainline earnings are anticipated to be lower in 2015 primarily as the result of the 2015 – 2030 Tolls and Tariff Application approved by the NEB in November 2014. These lower earnings are expected to be largely offset by growth in the NGTL System investment base as we connect new natural gas supply in northeastern B.C. and western Alberta and respond to growing demand in the oil sands market in northeast Alberta.

U.S. and International Gas Pipelines earnings are expected to be higher in 2015 primarily due to new long-term contracts for ANR originating from the Utica/Marcellus shale plays.

Earnings from our existing Mexican pipeline operations are expected to be consistent with 2014.

Liquids Pipelines

Earnings in 2015 from the Liquids Pipelines segment are not expected to be significantly different than 2014. We continue to seek further operational efficiencies which would, depending on market demand, improve capacity and flows on the Keystone Pipeline System.

Over time, Liquids Pipelines' earnings will increase as projects currently in development are placed in service.

Energy

Earnings in the Energy segment are generally maximized by maintaining and optimizing the operations of our power plants and through various marketing activities. Although a significant portion of Energy's output is sold under long-term contracts, output that is sold under shorter-term arrangements or at spot prices will continue to be affected by fluctuations in commodity prices.

Western Power earnings are anticipated to be lower in 2015 as a result of changing market conditions. Despite continued robust power demand in Alberta, exclusive of any market supply challenges, new supply additions in 2015 are expected to result in downward pressure on spot prices.

Eastern Power earnings in 2015 are expected to be higher as a result of a full year of operations from the additional solar assets acquired in 2014 as well as higher contractual earnings at Bécancour.

Bruce Power equity income is expected to be lower primarily due to the increased planned maintenance activity and higher operating costs.

U.S. Power earnings are anticipated to increase as a result of higher net energy margins and production partially offset by lower capacity prices for Ravenswood as a result of new supply entering the market in 2015.

Natural Gas Storage earnings are expected to be slightly lower in 2015 with fewer opportunities to realize shorter-term gas cycling gains such as those realized during periods of extreme volatility in 2014.

Consolidated capital spending and equity investments

We expect to spend approximately $6 billion in 2015 on new and existing capital projects. The 2015 capital spending relates to Natural Gas Pipeline projects including NGTL System expansion, the Canadian Mainline, Topolobampo, and Mazatlan; Liquids Pipeline projects including Grand Rapids, Northern Courier, Energy East and Heartland; and Energy projects including Napanee.

Natural Gas Pipelines

Our natural gas pipeline network transports natural gas to local distribution companies, power generation facilities and other businesses across Canada, the U.S. and Mexico. We serve more than 80 per cent of the Canadian demand and approximately 15 per cent of the U.S. demand on a daily basis by connecting major natural gas supply basins and markets through:

- wholly-owned natural gas pipelines – 57,000 km (35,500 miles)
- partially-owned natural gas pipelines – 11,000 km (6,600 miles).

We also have regulated natural gas storage facilities in Michigan with a total capacity of 250 Bcf, making us one of the largest providers of natural gas storage and related services in North America.

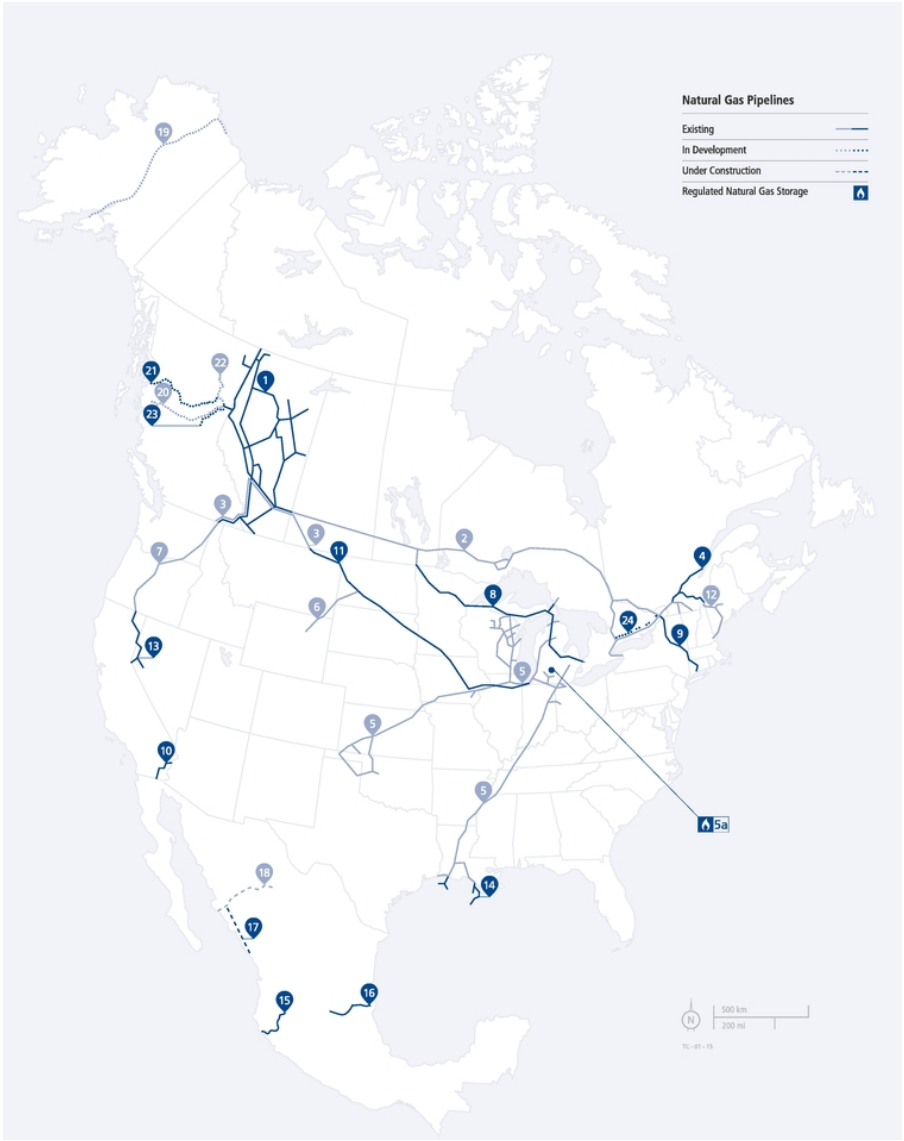
Strategy at a glance

Optimizing the value of our existing natural gas pipelines systems, while responding to the changing flow patterns of natural gas in North America, is a top priority.

We are also pursuing new pipeline projects to add incremental value to our business. Our key areas of focus include:

- greenfield development opportunities, such as infrastructure for liquefied natural gas (LNG) exports from the west coast of Canada and the Gulf of Mexico
- additional new pipeline developments within Mexico
- connections to emerging Canadian and U.S. shale gas and other supplies
- connections to new and growing markets

all of which play a critical role in meeting the transportation requirements for supply and demand for natural gas in North America.


Natural Gas Pipelines
Existing
In Development
Under Construction
Regulated Natural Gas Storage
19
21
22
20
23
1
3
3
11
2
7
6
8
4
12
24
9
13
5
10
5
5
5a
18
14
17
15
16
500 km
200 mi

We are the operator of all of the following natural gas pipelines and regulated natural gas storage assets except for Iroquois.

		length	description	effective ownership
	Canadian pipelines			
1	NGTL System	24,525 km (15,239 miles)	Receives, transports and delivers natural gas within Alberta and B.C., and connects with the Canadian Mainline, Foothills system and third-party pipelines	100%
2	Canadian Mainline	14,114 km (8,770 miles)	Transports natural gas from the Alberta/Saskatchewan border and the Ontario/U.S. border to serve eastern Canada and interconnects to the U.S.	100%
3	Foothills	1,241 km (771 miles)	Transports natural gas from central Alberta to the U.S. border for export to the U.S. Midwest, Pacific northwest, California and Nevada	100%
4	Trans Québec & Maritimes (TQM)	572 km (355 miles)	Connects with Canadian Mainline near the Ontario/Québec border to transport natural gas to the Montréal to Québec City corridor, and connects with the Portland pipeline system that serves the northeast U.S.	50%
	U.S. pipelines			
5	ANR Pipeline	15,109 km (9,388 miles)	Transports natural gas from supply basins to markets throughout the mid-west and south to the Gulf of Mexico.	100%
5a	ANR Storage	250 Bcf	Provides regulated underground natural gas storage service from facilities located in Michigan	
6	Bison	487 km (303 miles)	Transports natural gas from the Powder River Basin in Wyoming to Northern Border in North Dakota. We effectively own 28.3 per cent of the system through our interest in TC PipeLines, LP	28.3%
7	Gas Transmission Northwest (GTN)	2,178 km (1,353 miles)	Transports natural gas from the WCSB and the Rocky Mountains to Washington, Oregon and California. Connects with Tuscarora and Foothills. We effectively own 49.8 per cent of the system through the combination of our 30 per cent direct ownership interest and our 28.3 per cent interest in TC PipeLines, LP	49.8%
8	Great Lakes	3,404 km (2,115 miles)	Connects with the Canadian Mainline near Emerson, Manitoba and St Clair, Ontario, plus interconnects with ANR at Crystal Falls and Farwell in Michigan, to transport natural gas to eastern Canada, and the U.S. upper Midwest. We effectively own 66.7 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 28.3 per cent interest in TC PipeLines, LP	66.77%
9	Iroquois	666 km (414 miles)	Connects with Canadian Mainline near Waddington, New York to deliver natural gas to customers in the U.S. northeast	44.5%
10	North Baja	138 km (86 miles)	Transports natural gas between Arizona and California, and connects with a third-party pipeline on the California/Mexico border. We effectively own 28.3 per cent of the system through our interest in TC PipeLines, LP	28.3%
11	Northern Border	2,265 km (1,407 miles)	Transports WCSB and Rockies natural gas with connections to Foothills and Bison to U.S. Midwest markets. We effectively own 14.2 per cent of the system through our 28.3 per cent interest in TC PipeLines, LP	14.2%

		length	description	effective ownership
	U.S. pipelines			
12	Portland	474 km (295 miles)	Connects with TQM near East Hereford, Québec, to deliver natural gas to customers in the U.S. northeast	61.7%
13	Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to markets in northeastern California and northwestern Nevada. We effectively own 28.3 per cent of the system through our interest in TC PipeLines, LP	28.3%
14	TC Offshore	958 km (595 miles)	Gathers and transports natural gas within the Gulf of Mexico with subsea pipeline and seven offshore platforms to connect in Louisiana with our ANR pipeline system.	100%
	Mexican pipelines			
15	Guadalajara	310 km (193 miles)	Transports natural gas from Manzanillo, Colima to Guadalajara, Jalisco	100%
16	Tamazunchale	365 km (227 miles)	Transports natural gas from Naranjos, Veracruz in east central Mexico to Tamazunchale, San Luis Potosi and on to to El Sauz, Queretaro	100%
	Under construction			
17	Mazatlan Pipeline	413 km (257 miles)	To deliver natural gas from El Oro to Mazatlan, Sinaloa in Mexico. Will connect to the Topolobampo Pipeline at El Oro	100%
18	Topolobampo Pipeline	530 km (329 miles)	To deliver natural gas to Topolobampo, Sinaloa, from interconnects with third-party pipelines in El Oro, Sinaloa and El Encino, Chihuahua in Mexico	100%
	In development			
19	Alaska LNG Pipeline	1,448 km* (900 miles)	To transport natural gas from Prudhoe Bay to LNG facilities in Nikiski, Alaska	25%
20	Coastal GasLink	670 km* (416 miles)	To deliver natural gas from the Montney gas producing region at an expected interconnect on NGTL near Dawson Creek, B.C. to LNG Canada's proposed LNG facility near Kitimat, B.C.	100%
21	Prince Rupert Gas Transmission	900 km* (559 miles)	To deliver natural gas from the North Montney gas producing region at an expected interconnect on NGTL near Fort St. John, B.C. to the proposed Pacific Northwest LNG facility near Prince Rupert, B.C.	100%
22	North Montney Mainline	301 km* (187 miles)	An extension of the NGTL System to receive natural gas from the North Montney gas producing region and connect to NGTL's existing Groundbirch Mainline and the proposed Prince Rupert Gas Transmission project	100%
23	Merrick Mainline	260 km* (161 miles)	To deliver natural gas from NGTL's existing Groundbirch Mainline near Dawson Creek, B.C. to its end point near the community of Summit Lake, B.C.	100%
24	Eastern Mainline	245 km* (152 miles)	Various pipeline and compression facilities expected to be added in the Eastern Triangle of the Canadian Mainline to meet the requirements of the existing shippers as well as new firm service requirements following the conversion of components of the Mainline to facilitate the Energy East project	100%
	NGTL 2016/17 Facilities**	540 km* (336 miles)	The expansion program comprised of 21 integrated projects of pipes, compression and metering to meet new incremental firm service requests on the NGTL System	100%

* Pipe lengths are estimates as final route is still under design
** Facilities are not shown on the map

RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure).

year ended December 31 (millions of $)	2014	2013	2012
Comparable EBITDA	**3,241**	2,852	2,741
Comparable depreciation and amortization	**(1,063)**	(1,013)	(933)
Comparable EBIT	**2,178**	1,839	1,808
Specific items:			
Gas Pacifico/INNERGY gain on sale	**9**	-	-
NEB 2013 Decision – 2012	**-**	42	-
Segmented earnings	**2,187**	1,881	1,808

Natural Gas Pipelines segmented earnings in 2014 increased by $306 million compared to 2013 and included $9 million related to the gain on sale of Gas Pacifico/INNERGY in November 2014 whereas the year ended December 31, 2013 included $42 million related to the 2012 impact of the NEB 2013 Decision. These amounts have been excluded in our calculation of comparable EBIT. The remainder of the Natural Gas Pipelines segmented earnings are equivalent to comparable EBIT which, along with comparable EBITDA, are discussed below.

year ended December 31 (millions of $)	2014	2013	2012
Canadian Pipelines			
Canadian Mainline	**1,334**	1,121	994
NGTL System	**856**	846	749
Foothills	**106**	114	120
Other Canadian pipelines[1]	**22**	26	29
Canadian Pipelines – comparable EBITDA	**2,318**	2,107	1,892
Comparable depreciation and amortization	**(821)**	(790)	(715)
Canadian Pipelines – comparable EBIT	**1,497**	1,317	1,177
U.S. and International Pipelines (in US$)			
ANR	**189**	188	254
TC PipeLines, LP[1,2]	**88**	72	74
Great Lakes[3]	**49**	34	62
Other U.S. pipelines (Bison[4], GTN[5], Iroquois[1], Portland[6])	**132**	183	223
Mexico (Guadalajara, Tamazunchale)	**160**	100	99
International and other[1,7]	**(10)**	(4)	5
Non-controlling interests[8]	**241**	186	161
U.S. and International Pipelines – comparable EBITDA	**849**	759	878
Comparable depreciation and amortization	**(219)**	(217)	(218)
U.S. and International Pipelines – comparable EBIT	**630**	542	660
Foreign exchange impact	**68**	15	-
U.S. and International Pipelines – comparable EBIT (Cdn$)	**698**	557	660
Business Development comparable EBITDA and comparable EBIT	**(17)**	(35)	(29)
Natural Gas Pipelines – comparable EBIT	**2,178**	1,839	1,808
Summary			
Natural Gas Pipelines – comparable EBITDA	**3,241**	2,852	2,741
Comparable depreciation and amortization	**(1,063)**	(1,013)	(933)
Natural Gas Pipelines – comparable EBIT	**2,178**	1,839	1,808

1 Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect our share of equity income from these investments. In November 2014, we sold our interest in Gas Pacifico/INNERGY.

[2] In August 2014, TC PipeLines, LP began its at-the-market equity issuance program which will decrease our ownership interest in TC PipeLines, LP going forward. Effective May 22, 2013, our ownership interest in TC PipeLines, LP decreased from 33.3 per cent to 28.9 per cent. On July 1, 2013, we sold 45 per cent of GTN and Bison to TC PipeLines, LP. On October 1, 2014, we sold our remaining 30 per cent interest in Bison to TC PipeLines, LP. The following shows our ownership interest in TC PipeLines, LP and our effective ownership of Bison, GTN, and Great Lakes through our ownership interest in TC PipeLines, LP for the periods presented.

	Ownership percentage as of			
	October 1, 2014	July 1, 2013	May 22, 2013	January 1, 2012
TC PipeLines, LP	28.3	28.9	28.9	33.3
Effective ownership through TC PipeLines, LP:				
Bison	28.3	20.2	7.2	8.3
GTN	19.8	20.2	7.2	8.3
Great Lakes	13.1	13.4	13.4	15.5

[3] Represents our 53.6 per cent direct ownership interest. The remaining 46.4 per cent is held by TC PipeLines, LP.

[4] Effective October 1, 2014 we have no direct ownership in Bison. Prior to that our direct ownership interest was 30 per cent effective July 1, 2013, 75 per cent effective May 2011 and 100 per cent prior to that date.

[5] Effective July 1, 2013, reflects our direct ownership interest of 30 per cent. Prior to that our direct ownership interest was 75 per cent.

[6] Represents our 61.7 per cent ownership interest.

[7] Includes our share of the equity income from Gas Pacifico/INNERGY and TransGas as well as general and administration costs relating to our U.S. and International Pipelines. In November 2014, we sold our interest in Gas Pacifico/INNERGY.

[8] Comparable EBITDA for the portions of TC PipeLines, LP and Portland we do not own.

Canadian Pipelines

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Net income			
Canadian Mainline – net income	**300**	361	187
Canadian Mainline – comparable earnings	**300**	277	187
NGTL System	**241**	243	208
Average investment base			
Canadian Mainline	**5,690**	5,841	5,737
NGTL System	**6,236**	5,938	5,501

Net income and comparable EBITDA for our rate-regulated Canadian Pipelines are primarily affected by our approved ROE, our investment base, the level of deemed common equity, carrying charges owed to shippers on the Canadian Mainline Tolls Stabilization Account (TSA), and incentive earnings. Changes in depreciation, financial charges and income taxes also impact comparable EBITDA but do not have a significant impact on net income as they are almost entirely recovered in revenue on a flow-through basis.

Canadian Mainline's comparable earnings this year increased by $23 million compared to 2013 because of higher incentive earnings, partially offset by higher carrying charges owed to shippers on the positive TSA balance and a lower average investment base. Among other things, the NEB 2013 Decision set out an ROE of 11.50 per cent on deemed common equity of 40 per cent for the years 2012 through 2017. Net income of $361 million recorded in 2013 included $84 million related to the 2012 impact of the NEB 2013 Decision, which was excluded from comparable earnings. Comparable earnings in 2013 were $90 million higher than 2012 because of the impact of the NEB 2013 Decision which approved incentive earnings and a higher ROE. The ROE used to record earnings in 2012 was 8.08 per cent on 40 per cent deemed common equity.

Net income for the NGTL System was $2 million lower in 2014 compared to 2013. The decrease in net income was due to increased OM&A costs at risk under the terms of the 2013-2014 NGTL Settlement approved by the NEB in November 2013, partially offset by a higher average investment base. The settlement included an ROE of 10.10 per cent on deemed common equity of 40 per cent and included annual fixed amounts for certain OM&A costs. Net income in 2013 was $35 million higher than 2012 because of a higher average investment base and a higher ROE. In 2012, the NGTL System was operating under the 2010-2012 Settlement which had

an ROE of 9.70 per cent on deemed common equity of 40 per cent and included an annual fixed amount for certain OM&A costs.

Comparable EBITDA and EBIT for the Canadian pipelines reflect the variances discussed above as well as variances in depreciation, financial charges and income tax which are substantially recovered in revenue on a flow-through basis and, therefore, do not have a significant impact on net income.

U.S. and International Pipelines

EBITDA for our U.S. operations is affected by contracted volume levels, actual volumes delivered and the rates charged, as well as by the cost of providing services, including OM&A and other costs as well as property taxes.

ANR is also affected by the level of contracting and the determination of rates driven by the market value of its storage capacity, storage related transportation services, and incidental commodity sales. ANR's pipeline and storage volumes and revenues are generally higher in the winter months because of the seasonal nature of its business.

Comparable EBITDA for the U.S. and International Pipelines was US$90 million higher in 2014 than 2013. This was due to the net effect of:

- higher earnings from the Tamazunchale Extension which was placed in service in 2014
- higher transportation revenue at Great Lakes mainly due to colder winter weather and increased demand
- lower contributions from GTN and Bison following the reductions in our effective ownership in each pipeline in July 2013 (GTN and Bison) and October 2014 (Bison)
- a stronger U.S. dollar had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. and International operations.

Comparable EBITDA for the U.S. and International Pipelines was US$119 million lower in 2013 than 2012. This was due to the net effect of:

- lower transportation and storage revenues at ANR partially offset by higher incidental commodity sales
- higher OM&A and other costs relating to services provided by other pipelines to ANR
- lower revenue at Great Lakes because of uncontracted capacity
- lower contributions from GTN and Bison due to the reduction of our effective ownership in each pipeline from 83 per cent in 2012 to 50 per cent, effective July 1, 2013
- higher contributions from Portland due to higher short term revenues
- a stronger U.S. dollar had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. and International operations.

Comparable depreciation and amortization

Comparable depreciation and amortization was $50 million higher in 2014 than in 2013 mainly because of a higher rate base for the NGTL System. Depreciation and amortization was $80 million higher in 2013 than in 2012 mainly because of a higher rate base for the NGTL System, as well as the impact of the Mainline NEB 2013 Decision discussed above.

Business development

In 2014, business development expenses were $18 million lower than 2013 due to a change in scope on the Alaska project and lower administrative costs, partially offset by higher spending on Mexican projects. Business development expenses were $6 million higher in 2013 compared to 2012 mainly due to a change in scope on the Alaska project. See page 54 for further discussion on Alaska.

OUTLOOK

Canadian Pipelines

Earnings
Earnings for Canadian Pipelines are affected most significantly by changes in investment base, ROE and regulated capital structure, and also by the terms of toll settlements or other toll proposals approved by the NEB.

For 2015, the Canadian Mainline will operate under the terms of the 2015 – 2030 Tolls and Tariff Application, the fundamentals of which were approved by the NEB in November 2014. The terms of the application decision include a lower ROE of 10.10 per cent on deemed common equity of 40 per cent, an incentive mechanism that has both upside and downside risk and a $20 million after-tax contribution through tolls from us. As a result, we expect Canadian Mainline 2015 earnings to be lower than 2014.

We expect the NGTL System investment base to continue to grow as we connect new natural gas supply in northeastern B.C. and western Alberta and respond to rising demand in the oil sands market in northeastern Alberta. We expect the growing investment base to have a positive impact on NGTL System earnings in 2015.

We also anticipate a modest level of investment in our other Canadian rate-regulated natural gas pipelines, but expect the average investment bases of these pipelines to continue to decline as annual depreciation outpaces capital investment, reducing their year-over-year earnings.

Under the current regulatory model, earnings from Canadian rate-regulated natural gas pipelines are not materially affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contracted capacity levels.

U.S. Pipelines

Earnings
U.S. Pipeline earnings are affected by the level of contracted capacity and the rates charged to customers. Our ability to recontract or sell capacity at favourable rates is influenced by prevailing market conditions and competitive factors, including alternatives available to end use customers in the form of competing natural gas pipelines and supply sources, in addition to broader macroeconomic conditions that might impact demand from certain customers or market segments. Earnings are also affected by the level of OM&A and other costs, which includes the impact of safety, environmental and other regulator's decisions.

Many of our U.S. natural gas pipelines are backed by long-term take-or-pay contracts that are expected to deliver stable and consistent financial performance. ANR and Great Lakes have had more commercial exposure from transportation and storage contract renewals in recent years, which resulted in reduced earnings in 2013 and 2014 as transportation and storage values were depressed to historically low levels.

ANR has secured new long term contracts and extended terms at maximum recourse rates for significant volumes originating from the Utica/Marcellus shale plays with contract start dates from late 2014 through late 2015. We continue to seek opportunities to expand upon this success along with those opportunities associated with continued growth in end use markets for natural gas. In addition, ANR and Great Lakes are examining commercial, regulatory and operational changes to continue to optimize their position in response to positive developments in supply fundamentals. As a result, we expect 2015 earnings from our U.S. Pipelines to increase slightly from 2014.

Mexican Pipelines
The 2015 earnings for our current operating assets in Mexico are expected to be consistent with 2014 due to the nature of the long-term contracts applicable to our Mexican pipeline systems.

Capital spending
We spent a total of $2.1 billion in 2014 for our natural gas pipelines in Canada, the U.S. and Mexico, and expect to spend $3.4 billion in 2015 primarily on the NGTL System expansion projects, the Topolobampo and

Mazatlan pipelines in Mexico and Canadian Mainline capacity projects. See page 105 for further discussion on liquidity risk.

UNDERSTANDING THE NATURAL GAS PIPELINES BUSINESS

Natural gas pipelines move natural gas from major sources of supply to locations or markets that use natural gas to meet their energy needs.

Our natural gas pipeline business builds, owns and operates a network of natural gas pipelines in North America that connects locations where gas is produced or interconnects with other pipelines to end customers such as local distribution companies, power generation facilities, industrial operations and other pipeline interconnects or end-users. The network includes pipelines that are buried underground and transport natural gas under high pressure, compressor stations that act like pumps to move the large volumes of natural gas along the pipeline and meter stations that record the amount of natural gas coming on the network at receipt locations and leaving the network at delivery locations.

Regulation of tolls and cost recovery

Our natural gas pipelines are generally regulated in Canada by the NEB, in the U.S. by the FERC and in Mexico by the CRE. The regulators approve construction of new pipeline facilities and ongoing operations of the infrastructure.

Regulators in Canada, the U.S. and Mexico allow us to recover costs to operate the network by collecting tolls, or payments, for services. Costs of operating the systems include a return on our capital invested in the assets or rate base, as well as the recovery of the rate base over time through depreciation. Other costs recovered include OM&A costs, income and property taxes, and interest on debt. The regulator reviews our costs to ensure they are prudent and approves tolls that provide us a reasonable opportunity to recover them.

Within their respective jurisdictions, the FERC and CRE approve maximum transportation rates. These rates are cost based and are designed to recover the pipeline's investment, operating expenses and a reasonable return for our investors. As the pipeline operator within these jurisdictions, we may negotiate lower rates with shippers.

Sometimes we enter into agreements or settlements with our shippers for tolls and cost recovery, which may include mutually beneficial performance incentives. The regulator must approve a settlement, including performance incentives, for it to be put into effect.

Generally, Canadian natural gas pipelines request the NEB to approve the pipeline's cost of service and tolls once a year, and recover or refund the variance between actual and expected revenues and costs in future years. The Canadian Mainline, however, operates under a fixed toll arrangement for its longer-term firm transportation services and has the flexibility to price its shorter-term and interruptible services in order to maximize its revenue.

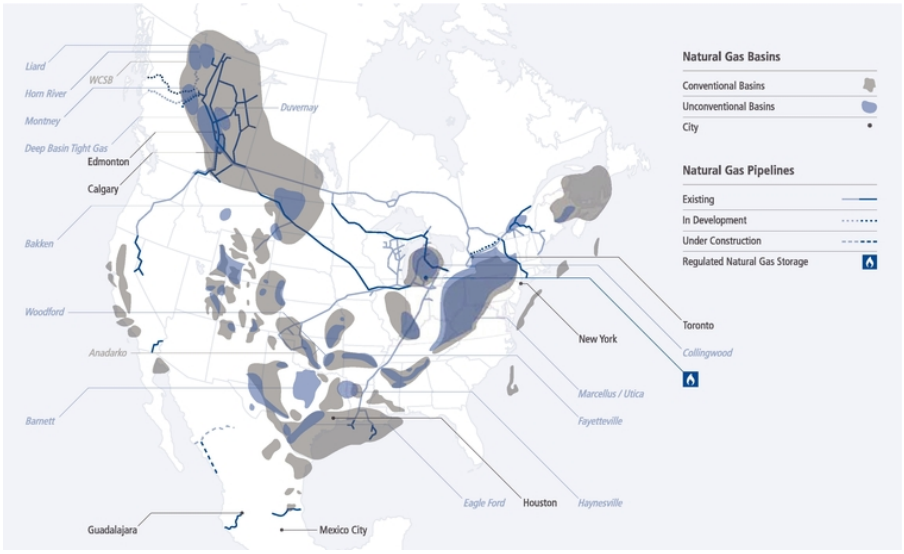
The FERC does not require U.S. interstate pipelines to calculate rates annually, nor do they allow for the collection or refund of the variance between actual and expected revenue and costs into future years. This difference in U.S. regulation puts our U.S. pipelines at risk for the difference in expected and actual costs and revenues between rate cases. If revenues no longer provide a reasonable opportunity to recover costs, we can file with the FERC for a new determination of rates, subject to any moratorium in effect. Similarly, the FERC may institute proceedings to lower tolls if they consider the return on the capital invested to be too high.

Our Mexican pipelines have approved tariffs, services and related rates. However, most of the contracts underpinning the construction and operation of the facilities in Mexico are long-term negotiated fixed-rate contracts. These rates are only subject to change under specific circumstances such as certain types of force majeure events or changes in law.

Business environment and strategic priorities

The North American natural gas pipeline network has developed to connect supply to market. Use and growth of this infrastructure is affected by changes in the location and relative cost of natural gas supplies as well as changes in the location of markets and level of demand.

We have a significant pipeline footprint in the WCSB and transport approximately 75 per cent of total WCSB production to markets within and outside of the basin. Our pipelines also source natural gas, to a lesser degree, from the other major basins including the Appalachian (Utica and Marcellus), Rockies, Williston, Haynesville, Fayetteville and Anadarko as well as the Gulf of Mexico.



Increasing supply

The WCSB spans almost all of Alberta and extends into B.C., Saskatchewan, Yukon and Northwest Territories and is Canada's primary source of natural gas supply. The WCSB is currently estimated to have 150 trillion cubic feet of remaining conventional resources and a technically accessible unconventional resource base of over 700 trillion cubic feet. The total recoverable WCSB resource base has recently more than quadrupled with the advent of technology that can economically access unconventional gas areas in the basin. Production from the WCSB increased slightly in 2014 after decreasing every year since 2007 and is expected to continue to increase over the next several years. The Montney and Horn River shale play formations and the Liard basin in northeastern B.C. are also part of the WCSB and have recently become a significant source of natural gas. We expect production from the Montney play that is currently just under 3 Bcf/d, to grow to approximately 6 Bcf/d by 2020, depending on the economics of exploration and production compared to other, mainly U.S., sources and the progress of proposed B.C. west coast LNG exports.

The primary sources of natural gas in the U.S. are the U.S. shale areas, Gulf of Mexico and the Rockies. The U.S. shales are the biggest area of growth which we estimate will meet almost 50 per cent of the overall North American gas demand by 2020. The largest shale developments for natural gas are the Utica/Marcellus basins in the northeast U.S. These basins have grown from essentially no production prior to 2008 up to 16 Bcf/d at the end of 2014. They are forecast to grow to 25 Bcf/d by 2020. Other natural gas supply from shale in the U.S. includes the Haynesville, Barnett, Eagle Ford and Fayetteville plays.

The overall supply of natural gas in North America is forecast to increase significantly over the next decade (by almost 20 Bcf/d or 22 per cent by 2020), and is expected to continue to increase over the long term for several reasons:

- continued technological progress with horizontal drilling and multi-stage hydraulic fracturing or fracking. This is increasing the technically accessible resource base of existing basins and emerging regions, such as the Marcellus and Utica in the U.S. northeast, and the Montney and Horn River areas in northeastern B.C.
- these technologies are also being applied to existing oil fields where further recovery of the resource is now possible. There is often associated gas discovered in the exploration and production of liquids-rich hydrocarbon basins, (for example, the Bakken oil fields) which also contributes to an increase in the overall gas supply for North America.

The development of shale gas basins that are located close to existing markets, particularly in the northeast U.S., has led to an increase in the number of supply choices and is expected to change historical gas pipeline flow patterns, generally from long-haul, long-term firm contracted capacity to shorter-distance, shorter-term contracts. Along with our competitors, we are restructuring our tolls and service offerings to capture this growing northeast supply and North American demand.

The Canadian Mainline is well positioned to offer optionality of supply to eastern Canadian and northeast U.S. markets, while still ensuring the opportunity to recover our costs including a return on the investment for both existing and new infrastructure as required.

Growing northeast supply has had a positive impact for both the Mainline, with new proposed facilities in eastern Canada, and our ANR U.S. pipeline assets, with significant new long-term contracts for service. The increase in supply in northeastern B.C. has created opportunities for us to plan and build, subject to regulatory approval and a positive final investment decisions (FID), new large pipeline infrastructure on the NGTL System to move the natural gas to markets, including proposed LNG exports and growing Alberta market demand.

Changing demand
The growing supply of natural gas has resulted in relatively low natural gas prices in North America, which have supported increased demand for natural gas particularly in the following areas:

- natural gas-fired power generation
- petrochemical and industrial facilities
- the production of Alberta oil sands
- exports to Mexico to fuel new power generation facilities.

Natural gas producers continue to progress opportunities to sell natural gas to global markets, which involves connecting natural gas supplies to new LNG export terminals which are proposed primarily along the west coast of B.C. and the U.S. Gulf of Mexico. Assuming the receipt of all necessary regulatory and other approvals, the proposed facilities along the west coast of B.C. are expected to become operational later in this decade. The U.S Gulf Coast also has several LNG export facilities in various stages of development or construction. LNG exports are expected to ramp up from this area, with initial deliveries beginning as early as late 2015. The demand created by the addition of these new markets creates opportunities for us to build new pipeline infrastructure and to increase throughput on our existing pipelines.

Commodity Prices
In general, the profitability of our gas pipelines business is not directly tied to commodity prices given we are a transporter of the commodity and the transportation costs are not tied to the price of natural gas. However, the cyclical supply and demand nature of commodities and its price impact can have an indirect impact on our business where our shippers may choose to accelerate or delay certain projects. This can impact the timing for the demand of transportation services and/or new gas pipeline infrastructure.

More competition
Changes in supply and demand levels and locations have resulted in increased competition for transportation services throughout North America. Development of technology for shale gas supply basins that are closer to markets historically served by long-haul pipelines has resulted in changes to flow patterns of existing natural gas pipeline infrastructure that includes reversing direction of flow and different distances of haul, particularly with the large development of U.S. northeast supply. Along with other pipelines, we are restructuring our tolls and service offerings to capture this growing northeast supply and North American demand.

Strategic priorities
We are focused on capturing opportunities resulting from growing natural gas supply, and connecting new markets, while satisfying increasing demand for natural gas within existing markets.We are also focused on adapting our existing assets to the changing gas flow dynamics.

The Canadian Mainline continued to be a focal point of our strategy in 2014. The cold 2013/14 winter coupled with the ability to price our discretionary services at market prices, resulted in a significant increase in long-haul firm transportation originating at Empress as well as increased revenue collection from the utilization of Mainline transportation services. The regulatory framework in place at the time did not allow us the opportunity to meet growing demand for new gas supplies to eastern Canada and recover the costs for those investments. As a result, an application for approval of 2015 to 2030 tolls was filed with the NEB based on the components reached in a settlement with the three major LDCs in Ontario and Québec. In November 2014, the NEB approved the application as filed (2015 – 2030 Tolls and Tariff Application). This approval sets the stage to advance capital projects in eastern Canada to meet the needs of our eastern Canada and northeast U.S. shippers seeking alternative supply sources. It also ensures a reasonable opportunity to recover the costs associated with our existing assets as well as those related to new pipeline investments.

In 2015, we will continue to advance the planned conversion of portions of the Canadian Mainline from natural gas service to crude oil service. The Energy East Pipeline is a planned project, subject to regulatory approval, to convert approximately 3,000 km (1,864 miles) of the Canadian Mainline from the Alberta border to a point in eastern Ontario, southeast of Ottawa, to crude oil service. We are committed to ensuring that our gas shipper community continues to receive transportation service to meet their firm service requirements.

The NGTL System is the major natural gas gathering and transportation system for the WCSB, connecting most of the natural gas production in western Canada to domestic and export markets. It faces competition for connection to supply, particularly in northeastern B.C., where the largest new source of natural gas has access to two other existing competing pipelines. Connections to new supply and new or growing demand continues to support new capital expansions of the NGTL System. We expect supply in the WCSB to grow from its current level of approximately 14 Bcf/d to approximately 16 Bcf/d by 2020. The NGTL System is well positioned to connect WCSB supply to meet expected demand for proposed LNG exports on the B.C. coastline. Obtaining the necessary regulatory approvals to extend and expand the NGTL System in northeastern B.C. to connect the Montney shale area was a key focus in 2014. A hearing process that examined the merits of our North Montney Pipeline project concluded in December 2014 and the NEB decision is expected by the end of April 2015.

Our U.S. pipeline assets are positioned for further connections to growth in supply and markets for the following reasons:

- Utica/Marcellus supply growth and increased demand for natural gas to supply Gulf Coast LNG export development supports additional ANR utilization, including the Lebanon Lateral project. We have attracted Utica supply to the ANR System with additional phases of further expansion expected
- expected continued growth in gas-fired generation should lead to increased load on our pipelines, including the proposed Carty lateral on the GTN system to deliver natural gas to a new power plant in Oregon
- growth in industrial load in response to robust levels of natural gas supply, including connections to the ANR System to serve a new customer in Iowa.

Management expects to drop down our remaining U.S. natural gas pipeline assets into TC PipeLines, LP as a means of funding a portion of our capital growth program, subject to the approvals of TC PipeLines, LP's board and our board as well as market conditions.

Our focus in Mexico in 2015 is to advance the construction phase for the Mazatlan and Topolobampo pipelines and to continue operating our existing facilities safely and reliably. We continue to be very interested in the further development of natural gas infrastructure in Mexico and will work to advance future projects, that align with our strategic priorities.

SIGNIFICANT EVENTS

Canadian Regulated Pipelines

NGTL System
We continue to experience significant growth on the NGTL System as a result of growing natural gas supply in northwestern Alberta and northeastern B.C. from unconventional gas plays and substantive growth in intra-basin delivery markets. This demand growth is driven primarily by oil sands development, gas-fired electric power generation and expectations of B.C. west coast LNG projects. This demand for NGTL System services is expected to result in approximately 4.0 Bcf/d of incremental firm services with approximately 3.1 Bcf/d related to firm receipt services and 0.9 Bcf/d related to firm delivery services. We will be seeking regulatory approvals in 2015 to construct new facilities to meet service requests of approximately 540 km (336 miles) of pipeline, seven compressor stations, and 40 meter stations that will be required in 2016 and 2017 (2016/17 Facilities). The estimated total capital cost for the facilities is approximately $2.7 billion.

Including the new 2016/17 Facilities, the North Montney Mainline, the Merrick Mainline, and other new supply and demand facilities, the NGTL System has approximately $6.7 billion of commercially secured projects in various stages of development.

North Montney Mainline
The $1.7 billion North Montney Pipeline is a proposed extension and expansion of the NGTL System to receive and transport natural gas from the North Montney area of B.C. The hearing for the application before the NEB to build and operate this project concluded in December 2014. We expect the NEB to issue its report and recommendations for the project by the end of April 2015.

Merrick Mainline
In June 2014, we announced the signing of agreements for approximately 1.9 Bcf/d of firm natural gas transportation services to underpin the development of a major extension of our NGTL System.

The proposed Merrick Mainline will transport natural gas sourced through the NGTL System to the inlet of the proposed Pacific Trail Pipeline that will terminate at the Kitimat LNG Terminal at Bish Cove near Kitimat, B.C. The proposed project will be an extension from the existing Groundbirch Mainline section of the NGTL System beginning near Dawson Creek, B.C. to its end point near the community of Summit Lake, B.C. The $1.9 billion project will consist of approximately 260 km (161 miles) of 48-inch diameter pipe.

Subject to the necessary approvals, which includes the regulatory approval from the NEB for us to build and operate the pipeline, and a positive final investment decision for the Kitimat LNG project, we expect the Merrick Mainline to be in service in first quarter 2020.

2015 Revenue Requirement Settlement
We received NEB approval on February 2, 2015 for our revenue requirement settlement with our shippers for 2015 on the NGTL System. The terms of the one year settlement include continuation of the 2014 ROE of 10.10 per cent on 40 per cent deemed equity, continuation of the 2014 depreciation rates and a mechanism for sharing variances above and below a fixed operating, maintenance and administrative expense amount that is based on an escalation of 2014 actual costs.

Canadian Mainline

2015 – 2030 Tolls and Tariff Application
On November 28, 2014, the NEB approved the Canadian Mainline's 2015 – 2030 Tolls and Tariff Application. The application reflected components of a settlement between the Canadian Mainline and the three major LDCs in Ontario and Québec. The approval of this application provides a long term commercial platform for both the Canadian Mainline and its shippers with a known toll design for 2015 to 2020 and certain parameters for a toll-setting methodology up to 2030. The platform balances the needs of our shippers while at the same time ensuring a reasonable opportunity to recover the capital from our existing facilities and any new facilities required to serve existing and new markets.

Highlights of the approved application include:

- our commitment to add increased pipeline capacity that allows eastern Canadian markets more access to Dawn and Niagara area supplies
- renewal provisions that will give us the tools to gain more certainty over capacity requirements
- fixed price tolls on one-year and longer firm transportation service
- continued pricing discretion for shorter term and interruptible service
- a known revenue requirement along with an incentive sharing mechanism that targets a return of 10.10 per cent on a deemed common equity of 40 per cent, with a possible range of outcomes from 8.70 per cent to 11.50 per cent
- the continued use of a deferral account that compensates for the differences between actual revenues and the fixed toll arrangement, plus an agreement that any overall variance in revenues for the 2015-2020 period is assigned to the eastern area shippers for the period beyond 2020.

Eastern Mainline Project
In October 2014, we filed an application seeking NEB approval to build, own and operate new facilities for our existing Canadian Mainline natural gas transmission system in southeastern Ontario (Eastern Mainline Project). The new facilities are a result of the proposed transfer of a portion of the Canadian Mainline capacity from natural gas service to crude oil service as part of our Energy East Pipeline and an open season that closed in January 2014. The $1.5 billion capital project will add 0.6 Bcf/d of new capacity in the Eastern Triangle segment of the Canadian Mainline and will ensure appropriate levels of capacity are available to meet the requirements of existing shippers as well as new firm service commitments. The project is contingent upon the Energy East Pipeline and is subject to regulatory approvals expected to be issued simultaneously with regulatory approvals for the Energy East Pipeline. The project is expected to be in service by second quarter 2017.

Other Canadian Mainline Expansions
In addition to the Eastern Mainline Project, we have executed new short haul arrangements in the Eastern Triangle portion of the Canadian Mainline that require new facilities, or modifications to existing facilities with a total capital cost of approximately $475 million with expected in-service dates between November 1, 2015 and November 1, 2016. These projects are subject to regulatory approval and, once constructed, will provide capacity needed to meet customer requirements in eastern Canada.

U.S. Pipelines

Sale of Bison Pipeline to TC PipeLines, LP
In October 2014, we closed the sale of our remaining 30 per cent interest in Bison Pipeline LLC to our master limited partnership, TC PipeLines, LP, for cash proceeds of US$215 million.

Sale of GTN Pipeline to TC PipeLines, LP
In November 2014, we announced an offer to sell the remaining 30 per cent interest in Gas Transmission Northwest LLC (GTN) to TC PipeLines, LP. Subject to the satisfactory negotiation of terms and TC PipeLines, LP's board approval, the transaction is expected to close in late first quarter 2015.

At December 31, 2014, we held a 28.3 per cent interest in TC PipeLines, LP for which we are the General Partner.

ANR Pipeline
We have secured nearly 2.0 Bcf/d of firm natural gas transportation commitments for existing and expanded capacity on ANR Pipeline's Southeast Main Line (SEML). The capacity sales and expansion projects include reversing the Lebanon Lateral in western Ohio, additional compression at Sulphur Springs, Indiana, expanding the Rockies Express pipeline interconnect near Shelbyville, Indiana and 600 MMcf/d of capacity as part of a reversal project on the SEML. Capital costs associated with the ANR System expansions required to bring the additional capacity to market are currently estimated to be US$150 million. The capacity was subscribed at maximum rates for an average term of 23 years with approximately 1.25 Bcf/d of new contracts beginning service in late 2014. These secured contracts on the SEML will move Utica and Marcellus shale gas to points north and south on the system.

ANR is also assessing further demand from our customers to transport natural gas from the Utica/Marcellus formation, which is expected to result in incremental opportunities to enhance and expand the system.

Mexican Pipelines

Tamazunchale Pipeline Extension
Construction of the US$600 million extension was completed November 6, 2014. Delays from the original service commencement date of March 9, 2014 were attributed primarily to archeological findings along the pipeline route. Under the terms of the Transportation Service Agreement, these delays were recognized as a force majeure with provisions allowing for collection of revenue from the original service commencement date.

Topolobampo and Mazatlan Pipelines
Permitting, engineering, and construction activities are advancing as planned for these two northwest Mexico pipelines. The Topolobampo project is a 530 km (329 miles), 30-inch pipeline with a capacity of 670 MMcf/d and a cost of US$1 billion that will deliver gas to Topolobampo, Sinaloa from interconnects with third party pipelines in El Oro, Sinaloa and El Encino, Chihuahua in Mexico. The Mazatlan project is a 413 km (257 miles), 24-inch pipeline running from El Oro to Mazatlan within the state of Sinaloa with a capacity of 200 MMcf/d and an estimated cost of US$400 million. Both projects are supported by 25-year contracts with the CFE and are expected to be in service mid to late 2016.

International Gas Pipelines

Gas Pacifico/INNERGY sale
In November 2014, we closed the sale of our 30 per cent equity interests in Gas Pacifico/INNERGY at a price of $9 million. This sale marks our exit from the Southern Cone region of South America.

LNG Pipeline Projects

Coastal GasLink
In October 2014, the B.C. Environmental Assessment Office issued an Environmental Assessment Certificate (EAC) for Coastal GasLink. In 2014, we also submitted applications to the B.C. Oil and Gas Commission (BC OGC) for the permits required under the Oil and Gas Activities Act to build and operate Coastal GasLink. Regulatory review of those applications is progressing on schedule, with permit decisions anticipated in first quarter 2015. We are currently continuing our engagement with Aboriginal groups and stakeholders along the pipeline route and are progressing detailed engineering and construction planning work to support the regulatory applications and refine the capital cost estimates. Pending the receipt of all required regulatory approvals and a positive FID from our customer, construction is anticipated in 2016, with an in-service date by the end of the decade. Should the project not proceed, our project costs (including AFUDC) are fully recoverable.

Prince Rupert Gas Transmission
On November 25, 2014, we received an EAC from the B.C. Environmental Assessment Office. We have submitted our pipeline permit applications to the BC OGC for construction of the pipeline and anticipate receiving these permits in first quarter 2015.

We have made significant changes to the project route since first announced, increasing it by 150 km (93 miles) to 900 km (559 miles), taking into account Aboriginal and stakeholder input. We continue to work closely with First Nations and stakeholders along the proposed route to create and deliver appropriate benefits to all impacted groups. In October 2014, we concluded a benefits agreement with the Nisga'a First Nation to allow 85 km (52 miles) of the proposed natural gas pipeline to run through Nisga'a Lands.

On December 3, 2014, our customer announced the deferral of an FID. We continue to work with our contractors to refine capital cost estimates for the project. Once the permitting process with the BC OGC is complete and Pacific NorthWest LNG secures the necessary regulatory approvals and proceeds with a positive FID, we will be in a position to begin construction. All costs would be fully recoverable should the project not proceed. The deferral of an FID past the end of 2014 has resulted in a deferral of the expected in-service date for the pipeline. The in-service date will depend on when our customer receives the necessary regulatory approvals and is in a position to make an FID.

Alaska
In April 2014, the State of Alaska passed new legislation to provide a framework for us, the three major Alaska North Slope producers (ANS Producers), and the Alaska Gasline Development Corp. (AGDC) to advance the development of an LNG export project, which is believed to be the best opportunity to commercialize Alaska North Slope gas resources in current market conditions. In June 2014, we executed an agreement with the State of Alaska to abandon the previous project governance and framework and executed a new precedent agreement where we will act as the transporter of the State's portion of natural gas under a long-term shipping contract in the Alaska LNG Project. We also entered into a Joint Venture Agreement with the three major ANS Producers and AGDC to commence the pre-front end engineering and design (pre-FEED) phase of Alaska LNG Project. The pre-FEED work is anticipated to take two years to complete with our share of the cost to be approximately US$100 million. The precedent agreement also provides us with full recovery of development costs in the event the project does not proceed.

In July 2014, the ANS Producers filed an export permit application with the U.S. Department of Energy for the right to export 20 million tonnes per annum of liquefied natural gas for 30 years. In September 2014, the FERC approved the National Environmental Policy Act (NEPA) pre-file request jointly made by us, the three major ANS Producers and AGDC. This approval triggers the NEPA environmental review process, which includes a series of community consultations.

BUSINESS RISKS

The following are risks specific to our natural gas pipelines business. See page 99 for information about general risks that affect the company as a whole, including other operational risks, health, safety and environment (HSE) risks, and financial risks.

WCSB supply for downstream connecting pipelines

Although we have diversified our sources of natural gas supply, many of our North American natural gas pipelines and transmission infrastructure assets depend largely on supply from the WCSB. We continue to monitor changes in the capital programs of our customers and how these changes may impact our project schedules.There is competition for this supply from several pipelines, demand within the basin and, in the future, demand for pipelines proposed for LNG exports from the west coast of B.C. An overall decrease in production and/or competing demand for supply, could impact throughput on WCSB connected pipelines that in turn could impact overall revenues generated. The WCSB has considerable reserves, but the amount actually produced depends on many variables, including the price of natural gas, basin-on-basin competition, downstream pipeline tolls, demand within the basin and the overall value of the reserves, including liquids content.

Market access

We compete for market share with other natural gas pipelines. New supply basins being developed closer to markets we have historically served may reduce the throughput and/or distance of haul on our existing pipelines that may impact revenue. The long-term competitiveness of our pipeline systems and the avoidance of bypass pipelines will depend on our ability to adapt to changing flow patterns by offering alternative transportation services at prices that are acceptable to the market.

Competition for greenfield expansion

We face competition from other pipeline companies seeking opportunities to invest in greenfield natural gas pipeline development opportunities. This competition could result in fewer projects being available that meet our investment hurdles or projects that proceed with lower overall financial returns.

Demand for pipeline capacity

Demand for pipeline capacity is ultimately the key driver that enables pipeline transportation services to be sold. 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. Renewal of expiring contracts, and the opportunity to charge and collect a toll that the market requires depends on the overall demand for transportation service. A change in the level of demand for our pipeline transportation services could impact revenues.

Commodity Prices

The cyclical supply and demand nature of commodities and related pricing can have a secondary impact on our business where our shippers may choose to accelerate or delay certain projects. This can impact the timing for the demand of transportation services and/or new gas pipeline infrastructure. As well, sustained low gas prices could impact our shippers' financial situation and their ability to meet their transportation service cost obligations.

Regulatory risk

Decisions by regulators can have an impact on the approval, timing, construction, operation and financial performance of our natural gas pipelines. There is a risk that decisions are delayed or are not favourable and therefore could impact revenues and the opportunity to further invest capital in our systems. There is also risk of a regulator disallowing a portion of our prudently incurred costs, now or at some point in the future.

The regulatory approval process for larger infrastructure projects, including the time it takes to receive a decision could be slowed or unfavorable due to the influence from the evolving role of activists and their impact on public opinion and government policy related to natural gas pipeline infrastructure development.

Increased scrutiny of operating processes by the regulator or other enforcing agencies has the potential to increase operating costs. There is a risk of an impact to income if these costs are not fully recoverable.

We continuously monitor regulatory developments and decisions to determine the possible impact on our gas pipelines business. We also work closely with our stakeholders in the development of rate, facility and tariff applications and negotiated settlements, where possible.

Operational

Keeping our pipelines operating safely and reliably is essential to the success of our business. Interruptions in our pipeline operations impact our throughput capacity and may result in reduced revenue and can affect corporate reputation as well as customer and public confidence in our operations. We manage this by investing in a highly skilled workforce, operating prudently, using risk-based preventive maintenance programs and making effective capital investments. We use internal inspection equipment to check our pipelines regularly, and repair or replace them whenever necessary. We also calibrate the meters regularly to ensure accuracy, and continuously maintain compression equipment to ensure safe and reliable operation.

Liquids Pipelines

Our existing liquids pipeline infrastructure connects Alberta and U.S. crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas, as well as connecting U.S. crude oil supplies from the Cushing, Oklahoma hub to refining markets in the U.S Gulf Coast. Our proposed future pipeline infrastructure would also connect Canadian and U.S. crude oil supplies to refining markets in eastern Canada and overseas export markets, expand Canadian and U.S. crude oil to U.S. markets and connect condensate supplies to U.S. and Canadian markets.

Strategy at a glance

With the increasing production of crude oil in Alberta and the U.S. and the growing demand for secure, reliable sources of energy, developing new liquids pipeline capacity and related infrastructure is essential.

We continue to focus on accessing and delivering growing North American liquids supply to key markets, and are planning to expand our liquids transportation infrastructure to deliver supply directly from producing regions seamlessly along a contiguous path to the market.

We see the potential for expanding transportation service offerings to other areas of the liquids pipelines value chain such as condensate transportation or ancillary services such as short and long-term storage of liquids, which complement our pipeline transportation infrastructure.

Construction of these infrastructure projects will provide North America with a key liquids transportation network to transport growing crude oil supply directly to key markets and provide opportunities for us to further expand our liquids pipelines business.


Liquids Pipelines
Existing
In Development
Under Construction
Crude Oil Terminal
35
31
30
34
29
36
37
32
33
25
26
27
28
N
500 km
200 mi

We are the operator of all of the following pipelines and properties.

		length	description	ownership
	Liquids pipelines			
25	Keystone Pipeline System	4,247 km (2,639 miles)	Transports crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka Illinois, Cushing, Oklahoma, and Port Arthur, Texas	100%
26	Cushing Marketlink		Transports crude oil from the market hub at Cushing, Oklahoma to the Port Arthur, Texas refining market on facilities that form part of the Keystone Pipeline System	100%
	Under construction			
27 28	Houston Lateral and Houston Terminal	77 km (48 miles)	To extend the Keystone Pipeline System to the Houston, Texas refining market	100%
29	Keystone Hardisty Terminal		Crude oil terminal located at Hardisty, Alberta, providing western Canadian producers with crude oil batch accumulation tankage and access to the Keystone Pipeline System	100%
30	Grand Rapids Pipeline	460 km (287 miles)	To transport crude oil and diluent between the producing area northwest of Fort McMurray, Alberta and the Edmonton/Heartland, Alberta market region	50%
31	Northern Courier Pipeline	90 km (56 miles)	To transport bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta	100%
	In development			
32	Bakken Marketlink		To transport crude oil from the Williston Basin producing region in North Dakota and Montana to Cushing, Oklahoma on facilities that form part of Keystone XL	100%
33	Keystone XL	1,897 km (1,179 miles)	To transport crude oil from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System	100%
34 35	Heartland Pipeline and TC Terminals	200 km (125 miles)	Terminal and pipeline facilities to transport crude oil from the Edmonton/Heartland, Alberta region to facilities in Hardisty, Alberta	100%
36	Energy East Pipeline	4,600 km (2,850 miles)	To transport crude oil from western Canada to eastern Canadian refineries and export markets	100%
37	Upland Pipeline	460 km (285 miles)	To transport crude oil from, and between, multiple points in North Dakota and interconnect with the Energy East Pipeline at Moosomin, Saskatchewan	100%

RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure).

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Comparable EBITDA	**1,059**	752	698
Comparable depreciation and amortization	**(216)**	(149)	(145)
Comparable EBIT	**843**	603	553
Specific items	**–**	–	–
Segmented earnings	**843**	603	553

Liquids Pipelines segmented earnings were $240 million higher in 2014 than in 2013 and $50 million higher in 2013 than in 2012. Liquids Pipelines segmented earnings are equivalent to comparable EBIT, which along with comparable EBITDA, are discussed below.

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Keystone Pipeline System	**1,073**	766	712
Liquids Pipelines Business Development	**(14)**	(14)	(14)
Liquids Pipelines – comparable EBITDA	**1,059**	752	698
Comparable depreciation and amortization	**(216)**	(149)	(145)
Liquids Pipelines – comparable EBIT	**843**	603	553
Comparable EBIT denominated as follows			
Canadian dollars	**215**	201	191
U.S. dollars	**570**	389	363
Foreign exchange impact	**58**	13	(1)
Liquids Pipelines – comparable EBIT	**843**	603	553

Comparable EBITDA

Comparable EBITDA for the Keystone Pipeline System was $307 million higher this year than in 2013. This increase was primarily due to:

- incremental earnings from the Keystone Gulf Coast extension which was placed in service in January 2014
- a stronger U.S. dollar which had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

Comparable EBITDA for the Keystone Pipeline System was $54 million higher in 2013 than in 2012. This increase reflected higher revenues primarily resulting from:

- higher volumes
- the impact of higher final fixed tolls on committed pipeline capacity to Cushing, Oklahoma, which came into effect in July 2012
- a stronger U.S. dollar which had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

Comparable depreciation and amortization

Comparable depreciation and amortization was $67 million higher in 2014 than in 2013 due to the Keystone Gulf Coast extension being placed in service.

OUTLOOK

Earnings

Our 2015 earnings are not expected to be significantly different than our 2014 earnings. We continue to seek further operational efficiencies which would, depending on market demand, improve capacity and flows on the Keystone Pipeline System.

Over time, Liquids Pipelines' earnings will increase as projects currently in development are placed in service.

Capital spending

We spent a total of $2.0 billion in 2014 on capital spending in Liquids Pipelines. We expect to spend approximately $2.3 billion on capital spending and equity investments in 2015, primarily on Grand Rapids, Northern Courier, Energy East and Heartland. See page 105 for further discussion on liquidity risk.

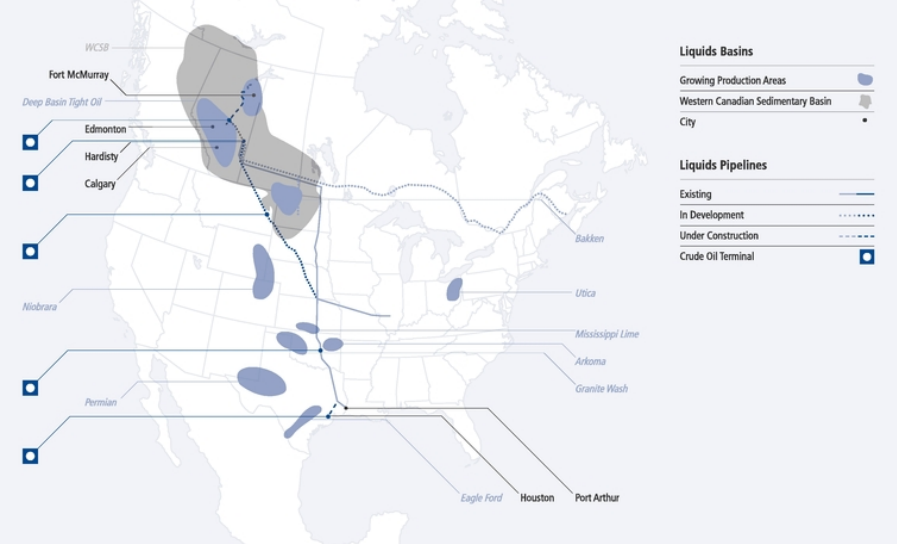
UNDERSTANDING THE LIQUIDS PIPELINES BUSINESS

In general, pipelines move crude oil from major supply sources to refinery markets so the crude oil can be refined into various petroleum products.

We generate earnings from our liquids pipelines mainly by providing pipeline capacity to shippers in exchange for fixed monthly payments that are not linked to actual throughput volumes. Uncontracted capacity is offered to the market on a spot basis which provides opportunities to generate incremental earnings.

The terms of service and fixed monthly payments are determined by transportation service arrangements negotiated with shippers. These arrangements are typically long term, and provide for the recovery of costs we incur to construct and operate the system.

Business environment and strategic priorities



Over the past decade, North American crude oil production has increased significantly in response to growth in global energy consumption and increased demand for crude oil. This growth in crude oil supply has increased the demand for new liquids pipeline infrastructure to connect these supplies to key North American and overseas markets. We have successfully secured a $25 billion portfolio of commercially secured projects to develop this infrastructure and we continue to pursue additional opportunities to expand our transportation service offerings to other areas of the value chain such as the long-term storage of liquids.

Recently, crude oil prices have declined sharply as continued growth in U.S. light oil supply, which has displaced North American imports, and growth in other global supplies has outpaced incremental demand. Although supplies from high cost production may be reduced if lower prices persist, our business is not expected to be significantly impacted by commodity price changes or supply reductions. Our existing operations and development projects are supported by long-term contracts where we have agreed to provide pipeline capacity to our customers in exchange for fixed monthly payments. The cyclical supply and demand nature of commodities and its price movements can have a secondary impact on our business where our shippers may choose to accelerate or delay certain new projects. This can impact the timing for the demand of transportation services and/or new liquids pipeline infrastructure.

Commodity price fluctuations are a normal part of the business cycle. Longer-term, we expect global demand for crude oil will continue to grow resulting in continued growth in North American crude oil supply production and demand for new pipeline infrastructure. Our growing position in the crude oil transportation business is creating a significant platform to capture these future growth opportunities.

Supply outlook

Canada
Alberta produces the majority of the crude oil in the WCSB which is the primary source of crude oil supply for the Keystone Pipeline System. In its 2014 Crude Oil Forecast, Markets and Transportation report, the Canadian Association of Petroleum Producers (CAPP) estimated 2015 WCSB crude oil production of 1.4 million Bbl/d of conventional crude oil and condensate and 2.2 million Bbl/d of oil sands crude oil, a total of approximately 3.6 million Bbl/d. The report forecasted WCSB crude oil production will increase to 4.6 million Bbl/d by 2020 and to 6.4 million Bbl/d by 2030.

In a January 2015 press release, CAPP announced estimated 2015 industry capital spending in western Canada, including oil sands development, would decline to $46 billion, $23 billion lower than forecasted in 2014. CAPP forecasts a slowing in the growth of crude oil production from the 2014 Crude Oil Forecast, Markets and Transportation report by 65,000 Bbl/d in 2015 and 120,000 Bbl/d in 2016. Although CAPP anticipates a decrease in capital spending, the revised forecast for total western Canadian crude oil production is approximately 150,000 higher in 2015 than in 2014.

According to the May 2014 *Alberta's Energy Reserves 2013 and Supply/Demand Outlook 2014-2023*, the Alberta Energy Regulator (AER) estimated there is approximately 167 billion barrels of economically and technically recoverable conventional and oil sands reserves in Alberta. Oil sands projects have a long reserve life. It is estimated that a typical oil sands mine has a 25 to 50 year lifespan, while an in-situ operation will run 10 to 15 years on average. This longevity aligns with the producer's desire to secure long-term connectivity of their reserves to market. The Keystone Pipeline System, including Keystone XL, and the proposed Energy East Pipeline are underpinned by long term contracts.

U.S.
According to the International Energy Agency World Energy Outlook 2014 Report, by 2020 the U.S. is set to surpass Saudi Arabia as the world's largest crude oil producer. The U.S. Energy Information Administration (EIA) projects over 1.0 million Bbl/d of U.S. production growth from 2014 to 2019, peaking at 9.6 million Bbl/d by 2019. Higher production volumes are mainly a result of recent advancements in shale oil production. EIA forecasts shale oil production peaking at approximately 4.8 million Bbl/d by 2020 and declining after 2022.

U.S. shale oil supply growth is mainly originating from the Bakken formation of the Williston basin in North Dakota and Montana, the Permian basin in south Texas and Woodford shale area of the Arkoma basin in Oklahoma. These shale production areas also represent some of the sources of crude oil supply for our Bakken Marketlink and Cushing Marketlink projects.

Growing U.S. production has contributed to increased crude oil supply at the Cushing, Oklahoma market hub and resulted in increased demand for additional pipeline capacity between Cushing, Oklahoma and the U.S. Gulf Coast refining market. Cushing Marketlink, which use facilities that form part of the Keystone Pipeline System, provides pipeline capacity to transport growing crude oil supply at Cushing, Oklahoma to the U.S. Gulf Coast.

Even with growth in U.S. crude oil production, the EIA report predicts the U.S. will remain a net importer of crude oil, importing 7.7 million Bbl/d into 2040. Growing production in the west Texas Permian, south Texas Eagle Ford and Williston basins is primarily light crude oil and is expected to compete with light imports from countries such as Nigeria and Saudi Arabia. Gulf Coast refiners are expected to continue to prefer Canadian heavy crude oil because these refineries are mainly configured to process heavy and medium crude oil and cannot easily switch to processing the new light shale oil in large quantities without significant capital investments. Gulf Coast refineries currently require approximately 3.5 million Bbl/d of heavy and medium crude oil, and the level of demand is not expected to change significantly in the future. The Keystone Pipeline System is well positioned to deliver Canadian crude oil to this significant market.

Strategic priorities

We are focused on advancing our current portfolio of commercially secured projects to connect growing Canadian and U.S. crude oil supply to key markets.

Securing regulatory approval for our $12 billion Energy East Pipeline is a key priority. In 2014, we filed necessary regulatory applications for approval to construct and operate this project and we are actively engaged with stakeholders as we work towards securing regulatory approval. Refineries in eastern Canada currently process primarily light crude oil imported from west Africa and the Middle East, and therefore could process North American light crude oil. According to the 2014 *Crude Oil Forecast, Markets and Transportation* report, total refining capacity in eastern Canada is approximately 1.2 million Bbl/d, and western Canada supplied only 354,000 Bbl/d to these eastern refineries. Due to insufficient pipeline capacity, many of these refineries have begun receiving domestic light crude oil in small quantities by rail at a cost significantly higher than the cost to ship by pipeline. This has created a significant demand for pipelines to connect eastern Canada with growing Bakken and WCSB light crude oil production. We anticipate that our Energy East Pipeline, once approved and constructed, will meet this demand.

We also remain fully committed to Keystone XL despite the unprecedented regulatory delays we have faced on this project. Keystone XL would expand the Keystone Pipeline System to provide more than 800,000 Bbl/d of additional capacity. This project is supported by long-term contracts and will transport crude oil from Canada as well as growing U.S. crude oil supplies to the large refining markets found in the American Midwest and along the U.S. Gulf Coast.

Within Alberta, we are leveraging our extensive natural gas pipeline footprint and experience to develop a regional liquids pipeline business. Growth in oil sands production is driving the need for new intra-Alberta pipelines, like our Grand Rapids Pipeline, that can move crude oil production from the source to market hubs at Edmonton/Heartland and Hardisty, Alberta as well as diluent from Edmonton/Heartland region to the production area in northern Alberta. The Heartland Pipeline and TC Terminals projects are intended to support these market hubs which will allow shippers the ability to connect with the Keystone Pipeline System, Energy East Pipeline and other pipelines that transport crude oil outside of Alberta to ultimately provide our customers with a contiguous seamless path from production to market.

As our liquids pipeline footprint continues to grow throughout North America, we are also pursuing other opportunities to expand our service offerings.These opportunities also include the development of rail transportation solutions, transportation of other liquids such as condensate, and the addition of terminal and liquids storage services to complement our existing infrastructure.

SIGNIFICANT EVENTS

Keystone Pipeline System

The completion of the Gulf Coast extension in January 2014 expanded the Keystone Pipeline System to a 4,247 km (2,639 miles) pipeline system that transports crude oil from Hardisty, Alberta, to markets in the U.S. Midwest and the U.S. Gulf Coast.

To date, the Keystone Pipeline System has delivered more than 830 million barrels of crude oil from Canada to the U.S.

Cushing Marketlink

Construction was completed on the Cushing Marketlink facilities at Cushing, Oklahoma in September 2014. Cushing Marketlink transports crude oil from the market hub at Cushing, Oklahoma to the U.S. Gulf Coast refining market on facilities that form part of the Keystone Pipeline System.

Houston Lateral and Terminal

Construction continues on the 77 km (48 miles) Houston Lateral pipeline and tank terminal which will extend the Keystone Pipeline System to Houston, Texas refineries. The terminal is expected to have initial storage capacity for 700,000 barrels of crude oil. The pipeline and terminal are expected to be completed in the second half of 2015.

Keystone XL

In January 2014, the DOS released its Final Supplemental Environmental Impact Statement (FSEIS) for the Keystone XL project. The results included in the report were consistent with previous environmental reviews of Keystone XL. The FSEIS concluded Keystone XL is "unlikely to significantly impact the rate of extraction in the oil sands" and that all other alternatives to Keystone XL are less efficient methods of transporting crude oil, and would result in significantly more greenhouse gas emissions, oil spills and risks to public safety. The report initiated the National Interest Determination period of up to 90 days which involves consultation with other governmental agencies and provides an opportunity for public comment. In April 2014, the DOS announced that the national interest determination period has been extended indefinitely to allow them to consider the potential impact of the case discussed below on the Nebraska portion of the pipeline route.

In February 2014, a Nebraska district court ruled that the state Public Service Commission, rather than Governor Dave Heineman, has the authority to approve an alternative route through Nebraska for Keystone XL. Nebraska's Attorney General filed an appeal which was heard by the Nebraska State Supreme Court on September 5, 2014. On January 9, 2015, the Nebraska State Supreme Court vacated the lower court's ruling that the law was unconstitutional. As a result, the Governor's January 2013 approval of the alternate route through Nebraska for Keystone XL remains valid. Landowners have filed lawsuits in two Nebraska counties seeking to enjoin Keystone XL from condemning easements on state constitutional grounds.

In September 2014, we filed a certification petition for Keystone XL with the South Dakota Public Utilities Commission (PUC). This certification confirms that the conditions under which Keystone XL's original June 2010 PUC construction permit was granted continue to be satisfied. The formal hearing for the certification is scheduled for May 2015.

On January 16, 2015, the DOS reinitiated the national interest review and requested the eight federal agencies, with a role in the review, to complete their consideration of whether Keystone XL serves the national interest and to provide their views to the DOS by February 2, 2015.

On February 2, 2015, the U.S. Environmental Protection Agency (EPA) posted a comment letter to its website suggesting that, among other things, the FSEIS issued by the DOS has not fully and completely assessed the environmental impacts of Keystone XL and that, at lower oil prices, Keystone XL may increase the rates of oil sands production and greenhouse gas emissions. On February 10, 2015, we sent a letter to the DOS refuting

these and other comments in the EPA letter but also offering to work with the DOS to ensure it has all the relevant information to allow it to reach a decision to approve Keystone XL.

The timing and ultimate approval of Keystone XL remain uncertain. In the event the project does not proceed as planned, we would reassess and reduce its carrying value to its recoverable amount if necessary and appropriate.

The estimated capital costs for Keystone XL are expected to be approximately US$8.0 billion. As of December 31, 2014, we have invested US$2.4 billion in the project and have also capitalized interest in the amount of US$0.4 billion.

Keystone Hardisty Terminal
The Keystone Hardisty Terminal will be constructed in conjunction with Keystone XL and is expected to be completed approximately two years from the date the Keystone XL permit is received.

Energy East Pipeline
In March 2014, we filed the project description for the Energy East Pipeline with the NEB. This was the first formal step in the regulatory process to receive the necessary approvals to build and operate the pipeline.

On October 30, 2014, we filed the necessary regulatory applications for approvals to construct and operate the Energy East Pipeline and terminal facilities with the NEB. The project is estimated to cost approximately $12 billion, excluding the transfer value of Canadian Mainline natural gas assets. Subject to regulatory approvals, the pipeline is anticipated to commence deliveries by the end of 2018.

The Energy East Pipeline includes a proposed marine terminal near Cacouna, Québec which would be adjacent to a beluga whale habitat. On December 8, 2014, the Committee on the Status of Endangered Wildlife in Canada recommended that beluga whales be placed on the endangered species list. As a result, we have made the decision to halt any further work at Cacouna and will be analyzing the recommendation, assessing any impacts to the project and reviewing all viable options. We intend to make a decision on how to proceed by the end of first quarter 2015.

The 1.1 million Bbl/d Energy East Pipeline received approximately one million Bbl/d of firm, long-term contracts to transport crude oil from western Canada that were secured during binding open seasons.

Northern Courier Pipeline
In July 2014, the AER issued a permit approving our application to construct and operate the Northern Courier Pipeline. Construction has started on the $900 million, 90 km (56 miles) pipeline to transport bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta. We currently expect the pipeline to be ready for service in 2017.

Heartland Pipeline and TC Terminals
The Heartland Pipeline is a 200 km (125 miles) crude oil pipeline connecting the Edmonton/Heartland, Alberta market region to facilities in Hardisty, Alberta. TC Terminals is a terminal facility in the Heartland industrial area north of Edmonton, Alberta.

The pipeline could transport up to 900,000 Bbl/d, while the terminal is expected to have initial storage capacity for up to 1.9 million barrels of crude oil. In February 2014, the application for the terminal facility was approved and construction commenced in October 2014.

These projects together have a combined estimated cost of $900 million and are expected to be placed in service in late 2017.

Grand Rapids Pipeline
On October 9, 2014, the AER issued a permit approving our application to construct and operate the Grand Rapids Pipeline. We have a partner through a joint venture, to develop Grand Rapids, a 460 km (287 miles) crude oil and diluent pipeline system connecting the producing area northwest of Fort McMurray, Alberta to

terminals in the Edmonton/Heartland, Alberta region. Each partner will own 50 per cent of the $3 billion pipeline project, and we will be the operator. Our partner has also entered into a long-term transportation service contract in support of Grand Rapids. Construction has commenced with initial crude oil transportation planned in 2016.

Upland Pipeline

In November 2014, we completed a successful binding open season for the Upland Pipeline. The $600 million pipeline would provide crude oil transportation from, and between multiple points in North Dakota and interconnect with the Energy East Pipeline System at Moosomin, Saskatchewan.

Subject to regulatory approvals, we anticipate the Upland Pipeline to be in service in 2018. The commercial contracts we have executed for Upland Pipeline are conditioned on Energy East proceeding.

BUSINESS RISKS

The following are risks specific to our liquids pipelines business. See page 99 for information about general risks that affect the company as a whole, including other operational risks, health, safety and environment (HSE) risks, and financial risks.

Operational

Optimizing and maintaining availability of our liquids pipelines is essential to the success of our liquids pipelines business. Interruptions in our pipeline operations impact our throughput capacity and may result in reduced fixed payment revenues and spot volume opportunities. We manage this by investing in a highly skilled workforce, operating prudently, using risk-based preventive maintenance programs and making effective capital investments. We use internal inspection equipment to check our pipelines regularly and repair them whenever necessary.

Regulatory

Decisions by Canadian and U.S. regulators can have a significant impact on the approval, construction, operation and financial performance of our liquids pipelines. Public opinion about crude oil development and production may also have an adverse impact on the regulatory process. There are some individuals and interest groups that are expressing their opposition to crude oil production by lobbying against the construction of liquids pipelines. We manage this risk by continuously monitoring regulatory developments and decisions to determine their possible impact on our liquids pipelines business and by working closely with our stakeholders in the development and operation of the assets.

Execution, capital costs and permitting

We make substantial capital commitments in large infrastructure projects based on the assumption that the new assets will offer an attractive return on investment in the future. Under some contracts, we share the cost of these risks with customers. While we carefully consider the expected cost of our capital projects, under some contracts we bear capital cost risk which may impact our return on these projects. Our capital projects are also subject to permitting risk which may result in construction delays, increased capital cost and, potentially, reduced investment returns.

Crude oil supply and demand for pipeline capacity

A decrease in demand for refined crude oil products could adversely impact the price that crude oil producers receive for their product. Lower prices for crude oil could mean producers may curtail their investment in the further development of crude oil supplies. Depending on their severity, these factors would negatively impact the opportunities we have to expand our crude oil pipeline infrastructure and, in the longer term, to re-contract with shippers as current agreements expire.

Competition

As we continue to develop a competitive position in the North American liquids transportation market to transport growing WCSB, Williston, Permian and Arkoma basins crude oil supplies to key North American refining markets and export markets, we face competition from other pipeline companies, and to a lesser extent, rail companies which also seek to transport these crude oil supplies to the same markets. Our success is dependent on our ability to offer and contract transportation services on terms that are market competitive.

Energy

Our Energy business includes a portfolio of power generation assets in Canada and the U.S., and unregulated natural gas storage assets in Alberta.

We own, control or are developing approximately 11,800 MW of generation capacity powered by natural gas, nuclear, coal, hydro, wind and solar assets. Our power business in Canada is mainly located in Alberta, Ontario and Québec. Our power business in the U.S. is located in New York, New England, and Arizona. The assets are largely supported by long-term contracts and some represent low-cost baseload generation, while others are critically located, essential capacity.

We conduct wholesale and retail electricity marketing and trading throughout North America from our offices in Alberta, Ontario and Massachusetts to actively manage our commodity exposure and provide higher returns.

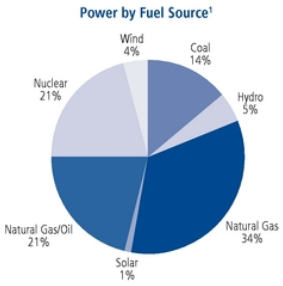
We own and operate approximately 118 Bcf of unregulated natural gas storage capacity in Alberta and hold a contract with a third party for additional storage, in total accounting for approximately one-third of all storage capacity in the province. When combined with the regulated natural gas storage in Michigan (part of the Natural Gas Pipelines segment), we provide over 350 Bcf of natural gas storage and related services.

Strategy at a glance

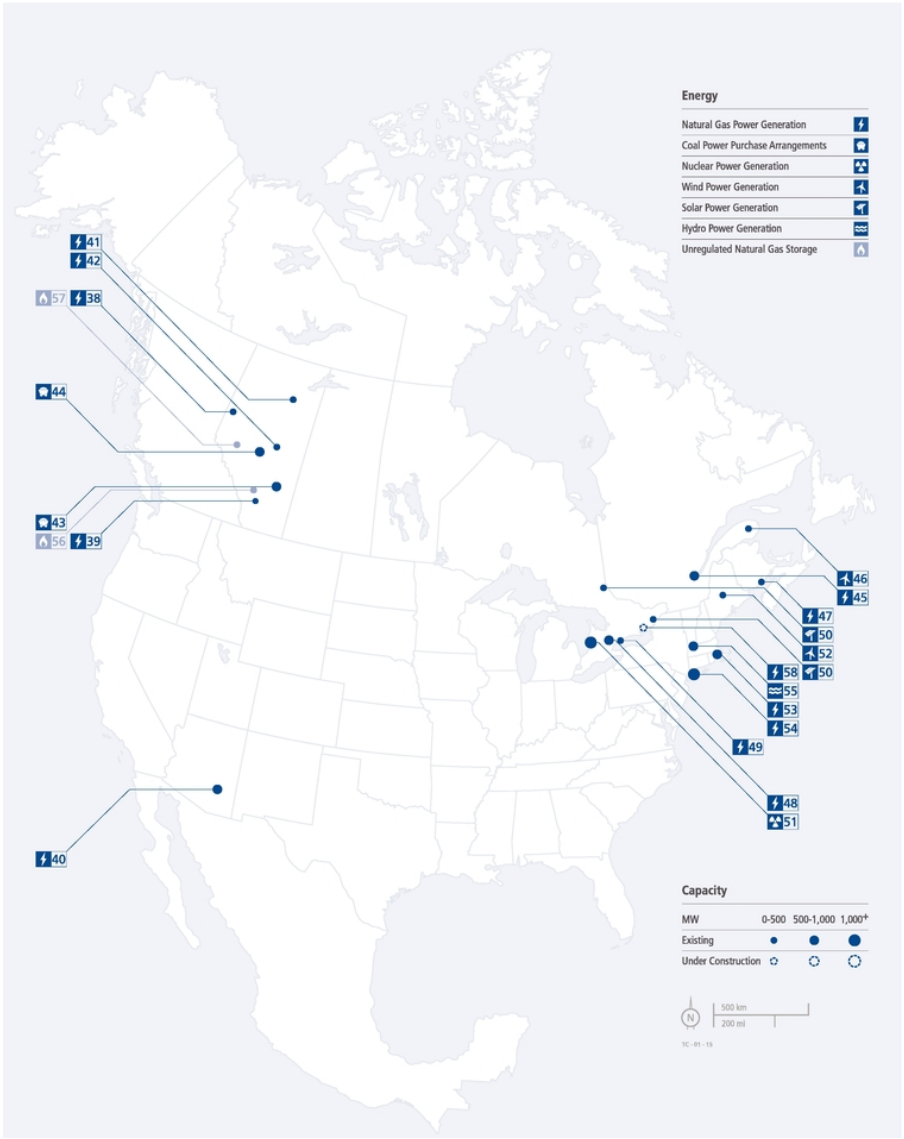
We are focusing on growing a portfolio of low-cost, long-life power generation and natural gas storage assets located in core North American markets, while maximizing the value of our existing investments through safe and reliable operations.

Growth opportunities in the North American power generation sector are arising from increasing demand for power and the need to replace aging power generation infrastructure with gas-fired and renewable generation plants as societal trends and policies continue to focus on lowering the carbon intensity of the generation fleet. We are well positioned to participate in the development of this new power generation infrastructure due to our strong presence and experience in core markets and the strategic locations of existing operations. Our recent investments in solar generation and the construction of the Napanee Generating Station in Ontario, both of which are underpinned with long-term contracts, are examples of such growth and opportunity. The potential for further nuclear refurbishment at Bruce Power is another example of the opportunities for us to further develop our diverse portfolio of generation technologies, fuel types, markets and contract structures.

Natural gas storage's role in balancing and providing reliability and flexibility to the natural gas system is expected to grow as the market expands and becomes more dynamic as a result of the electric grid's increased reliance on gas-fired capacity and from the addition of LNG export terminals. In the long-term, we expect an increased dependence on natural gas storage will drive higher returns from our gas storage operations.



[1] Includes facilities under construction.


Energy
Natural Gas Power Generation
Coal Power Purchase Arrangements
Nuclear Power Generation
Wind Power Generation
Solar Power Generation
Hydro Power Generation
Unregulated Natural Gas Storage
41
42
57
38
44
43
56
39
40
46
45
47
50
52
58
50
55
53
54
49
48
51
Capacity
MW
0-500
500-1,000
1,000+
Existing
Under Construction
N
500 km
200 mi
TC - 01 - 15

We are the operator of all of our Energy assets, except for the Sheerness, Sundance A and Sundance B PPAs, Cartier Wind, Bruce A and B and Portlands Energy.

		generating capacity (MW)	type of fuel	description	location	ownership
	Canadian Power 8,037 MW of power generation capacity (including facilities under construction)					
	Western Power 2,609 MW of power supply in Alberta and the western U.S.					
38	Bear Creek	80	natural gas	Cogeneration plant	Grande Prairie, Alberta	100%
39	Carseland	80	natural gas	Cogeneration plant	Carseland, Alberta	100%
40	Coolidge[1]	575	natural gas	Simple-cycle peaking facility	Coolidge, Arizona	100%
41	Mackay River	165	natural gas	Cogeneration plant	Fort McMurray, Alberta	100%
42	Redwater	40	natural gas	Cogeneration plant	Redwater, Alberta	100%
43	Sheerness PPA	756	coal	Output contracted under PPA	Hanna, Alberta	100%
44	Sundance A PPA	560	coal	Output contracted under PPA	Wabamun, Alberta	100%
44	Sundance B PPA (Owned by ASTC Power Partnership[2])	353[3]	coal	Output contracted under PPA	Wabamun, Alberta	50%
	Eastern Power 2,939 MW of power generation capacity (including facilities under construction)					
45	Bécancour	550	natural gas	Cogeneration plant	Trois-Rivières, Québec	100%
46	Cartier Wind	365[3]	wind	Five wind power projects	Gaspésie, Québec	62%
47	Grandview	90	natural gas	Cogeneration plant	Saint John, New Brunswick	100%
48	Halton Hills	683	natural gas	Combined-cycle plant	Halton Hills, Ontario	100%
49	Portlands Energy	275[3]	natural gas	Combined-cycle plant	Toronto, Ontario	50%
50	Ontario Solar	76	solar	Eight solar facilities	Southern Ontario and New Liskeard, Ontario	100%
	Bruce Power 2,489 MW of power generation capacity through eight nuclear power units					
51	Bruce A	1,467[3]	nuclear	Four operating reactors	Tiverton, Ontario	48.9%
51	Bruce B	1,022[3]	nuclear	Four operating reactors	Tiverton, Ontario	31.6%

		generating capacity (MW)	type of fuel	description	location	ownership
	U.S. Power 3,755 MW of power generation capacity					
52	Kibby Wind	132	wind	Wind farm	Kibby and Skinner Townships, Maine	100%
53	Ocean State Power	560	natural gas	Combined-cycle plant	Burrillville, Rhode Island	100%
54	Ravenswood	2,480	natural gas and oil	Multiple-unit generating facility using dual fuel-capable steam turbine, combined-cycle and combustion turbine technology	Queens, New York	100%
55	TC Hydro	583	hydro	13 hydroelectric facilities, including stations and associated dams and reservoirs	New Hampshire, Vermont and Massachusetts (on the Connecticut and Deerfield rivers)	100%
	Unregulated natural gas storage 118 Bcf of non-regulated natural gas storage capacity					
56	CrossAlta	68 Bcf		Underground facility connected to the NGTL System	Crossfield, Alberta	100%
57	Edson	50 Bcf		Underground facility connected to the NGTL System	Edson, Alberta	100%
	Under construction					
58	Napanee	900	natural gas	Combined-cycle plant	Greater Napanee, Ontario	100%

[1] Located in Arizona, results reported in Canadian Power – Western Power.

[2] We have a 50 per cent interest in ASTC Power Partnership, which has a PPA for production from the Sundance B power generating facilities.

[3] Our share of power generation capacity.

RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure).

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Comparable EBITDA	**1,348**	1,363	903
Comparable depreciation and amortization	**(309)**	(294)	(283)
Comparable EBIT	**1,039**	1,069	620
Specific items:			
Cancarb gain on sale	**108**	-	-
Niska contract termination	**(43)**	-	-
Sundance A PPA arbitration decision – 2011	**-**	-	(20)
Risk management activities	**(53)**	44	(21)
Segmented earnings	**1,051**	1,113	579

Energy segmented earnings were $62 million lower in 2014 than in 2013 and $534 million higher in 2013 than in 2012.

Energy segmented earnings included the following specific items:

- a gain of $108 million on the sale of Cancarb Limited and its related power generation business, which closed in April 2014
- a net loss of $43 million resulting from the contract termination payment to Niska Gas Storage effective April 30, 2014
- a net loss of $20 million resulting from the Sundance A PPA arbitration decision in July 2012 related to 2011
- unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain commodity price risks as follows:

Risk management activities (millions of $, pre-tax)	**2014**	**2013**	**2012**
Canadian Power	**(11)**	(4)	4
U.S. Power	**(55)**	50	(1)
Natural Gas Storage	**13**	(2)	(24)
Total (losses)/gains from risk management activities	**(53)**	44	(21)

The year over year variances in these unrealized gains and losses reflect the impact of changes in forward natural gas and power prices and the volume of our position for these particular derivatives over a certain period of time; however, they do not accurately reflect the gains and losses that will be realized on settlement, or the offsetting impact of other derivative and non-derivative transactions that make up our business as a whole. As a result, we do not consider them part of our underlying operations.

The specific items noted above have been excluded in our calculation of comparable EBIT. The remainder of the Energy segmented earnings are equivalent to comparable EBIT, which along with comparable EBITDA, are discussed below.

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Canadian Power			
Western Power	**252**	355	311
Eastern Power[1]	**350**	322	321
Bruce Power	**314**	310	14
Canadian Power – comparable EBITDA[2]	**916**	987	646
Comparable depreciation and amortization	**(179)**	(172)	(152)
Canadian Power – comparable EBIT[2]	**737**	815	494
U.S. Power (US$)			
U.S. Power – comparable EBITDA	**376**	323	209
Comparable depreciation and amortization	**(107)**	(107)	(121)
U.S. Power – comparable EBIT	**269**	216	88
Foreign exchange impact	**27**	7	-
U.S. Power – comparable EBIT (Cdn$)	**296**	223	88
Natural Gas Storage and other			
Natural Gas Storage and other – comparable EBITDA[2]	**44**	63	67
Comparable depreciation and amortization	**(12)**	(12)	(10)
Natural Gas Storage and other – comparable EBIT[2]	**32**	51	57
Business Development comparable EBITDA and EBIT	**(26)**	(20)	(19)
Energy – comparable EBIT[2]	**1,039**	1,069	620
Summary			
Energy – comparable EBITDA[2]	**1,348**	1,363	903
Comparable depreciation and amortization	**(309)**	(294)	(283)
Energy – comparable EBIT[2]	**1,039**	1,069	620

1 Includes four solar facilities acquired between June and December 2013, three solar facilities acquired in September 2014, one solar facility acquired in December 2014 and Cartier Wind phase two of Gros-Morne completed in November 2012.

2 Includes our share of equity income from our equity accounted for investments in ASTC Power Partnership, Portlands Energy, Bruce Power and CrossAlta up to December 2012. In December 2012, we acquired the remaining 40 per cent interest in CrossAlta, bringing our ownership interest to 100 per cent, and commenced consolidating their operations.

Comparable EBITDA for Energy was $15 million lower in 2014 than in 2013. The decrease was the effect of:

- lower earnings from Western Power due to lower realized prices
- higher earnings from U.S. Power mainly because of higher realized capacity prices in New York and higher realized power prices at our New York and New England facilities
- incremental earnings from Eastern Power primarily due to four solar facilities acquired in each of 2013 and 2014
- lower earnings from Natural Gas Storage due to lower realized natural gas storage price spreads.

Comparable EBITDA for Energy was $460 million higher in 2013 compared to 2012. This increase was the effect of:

- higher equity income from Bruce Power due to incremental earnings from Units 1 and 2 and lower planned outage days at Unit 4 as well as an insurance recovery related to the May 2012 Unit 2 electrical generation failure
- higher earnings from U.S. Power mainly because of higher realized capacity prices in New York and higher realized power prices
- higher earnings from Western Power primarily because of higher purchased volumes under the PPAs.

OUTLOOK

Earnings

We expect 2015 earnings from the Energy segment to be slightly lower than 2014, assuming the net effect of the following expectations:

- lower power prices in Alberta
- lower Bruce Power equity income due to increased planned maintenance activity and higher operating costs
- lower contributions from our Natural Gas Storage operations
- lower earnings as a result of the sale of Cancarb in April 2014
- lower realized capacity prices in New York
- higher contributions from U.S. Power assets due to increased net energy margins and production
- a full year of earnings from Ontario solar facilities acquired in 2014
- higher contributions from our power operations in Québec.

Although a significant portion of Energy's output is sold under long-term contracts, revenue from power that is sold under shorter-term forward arrangements or at spot prices will continue to be impacted by fluctuations in commodity prices and changes in seasonal natural gas storage price spreads will impact Natural Gas Storage earnings.

Weather, unplanned outages and unforeseen regulatory changes can play a role in spot markets and can drive fluctuations in our Energy results.

Western Power

2015 average spot power prices are expected to be slightly lower than 2014. The Alberta power market was relatively well supplied in 2014 and that trend is expected to be further entrenched in 2015 with the addition of a large gas-fired power plant in the Calgary area which is expected to be placed in service in first half 2015. Average spot market power prices in 2014 ($50/MWh) were much lower than 2013 ($80/MWh) primarily due to strong coal fleet availability and new wind generation capacity despite strong annual power demand growth of just over three per cent.

The Alberta Electric System Operator is forecasting healthy supply growth over the next 10 years in order to meet continued demand growth of over three per cent per year over the next 10 years. While some of this robust growth outlook in Alberta is underpinned by oil and gas activity and demand, it is also driven by the anticipated coal fleet turnover and need to replace other aging generation capacity being retired over time. We remain cautiously optimistic that the Alberta market will continue to outpace growth in other regions of North America.

Natural Gas Storage

Natural gas price spreads are expected to modestly improve from cyclical lows, however, extreme gas price volatility experienced in first quarter 2014 is not expected to repeat in first quarter 2015. As a result, the 2015 segment contribution is expected to be slightly lower compared to 2014 results.

Eastern Power

In January 2015, the OPA and the Independent Electricity System Operator (IESO) merged and now operate as one organization which is continuing under the name IESO. This merger does not impact the terms of any of our contracts with the OPA.

All of our energy assets in eastern Canada are fully contracted. The Ontario assets are contracted with the IESO and are largely sheltered from spot market pricing. Eastern Power earnings in 2015 are expected to be higher as a result of a full year of operations from the additional solar assets acquired in 2014 as well as higher contractual earnings at Bécancour.

The Ontario power market is currently well supplied despite the fact that the coal-fired fleet is now fully retired. The combination of flat system demand growth, partly due to conservation programs and increased nuclear and renewable output, is enabling Ontario to be a net exporter of electricity.

Bruce Power

We expect 2015 equity income from Bruce Power to be lower than 2014 primarily due to increased planned maintenance activity and higher costs at each of Bruce A and Bruce B. During second quarter 2015, all Bruce B units are expected to be removed from service for approximately one month to allow for inspection of the Bruce B vacuum building. The vacuum building is a key component of the site's safety systems and is required to be inspected approximately once every decade. Additional planned maintenance at Bruce B is scheduled to occur during second quarter 2015.

Planned maintenance at Bruce A is scheduled for first and third quarters of 2015.

Overall plant availability percentages in 2015 are expected to be in the mid 80s for Bruce A and Bruce B.

The Ontario government's 2013 Long-Term Energy Plan outlined their intentions on nuclear power's role in the fuel mix going forward. The potential refurbishment of six Bruce Power units was included within the plan and Bruce Power is actively considering the site's refurbishment options within this context.

U.S. Power

U.S. northeast markets experienced a colder than normal winter in 2014 with multiple polar vortex events and natural gas pipeline constraints causing high price volatility in the winter months. However, the summer months experienced below normal temperatures that reduced air conditioning power demand. In 2015, we expect to continue to experience price volatility in the winter months due to pipeline constraints; however, recent reductions in fuel oil prices are anticipated to keep peak price excursions limited compared to previous years. The New York and New England ISO forecasts growth in the demand for power of about one per cent per year in the coming years.

Our northeastern U.S. power facilities also earn significant revenues through participation in regional capacity markets. Capacity markets compensate power suppliers for being available to provide power, and as a result are intended to promote investment in new and existing power resources needed to meet customer demand and maintain a reliable power system. New York Spot capacity prices are on average expected to be lower in 2015 than 2014.

The timing of recognizing earnings from our U.S. power marketing business is impacted by different pricing profiles between the prices we charge our customers and the prices we pay for volumes purchased to fulfill our sales obligations over the term of the contracts. The costs on volumes purchased to fulfill power sales commitments to wholesale, commercial and industrial customers includes the impact of certain contracts to purchase power over multiple periods at a flat price. Because the price we charge our customers is typically shaped to the market, the impact of these two contract pricing profiles has generally resulted in higher earnings in January to March, offset by lower earnings between April and December with overall positive margins over the term of the contracts. Due to increased volatility of forward natural gas and power prices in the New England market, these timing differences will be more significant in 2015.

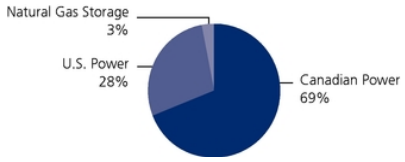
Capital spending
We spent a total of $0.2 billion in 2014, and expect to spend approximately $0.3 billion on capital spending in Energy in 2015. See page 105 for further discussion on liquidity risk.

Equity investments and acquisitions
In 2014, we also invested $0.2 billion on the acquisition of four Ontario solar facilities and $0.1 billion in Bruce Power for capital projects. We expect to spend approximately $0.2 billion on Bruce Power investments in 2015.

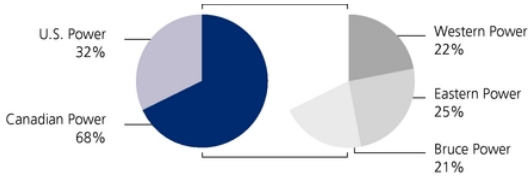
UNDERSTANDING THE ENERGY BUSINESS
Our Energy business is made up of three groups:

- Canadian Power
- U.S. Power
- Natural Gas Storage

Energy comparable EBIT – contribution by group, excluding business development expenses
year ended December 31, 2014



Power generation capacity – contribution by group
year ended December 31, 2014 (includes facilities in development)



Canadian Power

Western Power
We own or have the rights to approximately 2,600 MW of power supply in Alberta and Arizona through three long-term PPAs, five natural gas-fired cogeneration facilities, and through Coolidge, a simple-cycle, natural gas peaking facility in Arizona.

Power purchased under long-term contracts is as follows:

	Type of contract	With	Expires
Sheerness PPA	Power purchased under a 20-year PPA	ATCO Power and TransAlta Utilities Corporation	2020
Sundance A PPA	Power purchased under a 20-year PPA	TransAlta Utilities Corporation	2017
Sundance B PPA	Power purchased under a 20-year PPA (own 50 per cent through the ASTC Power Partnership)	TransAlta Utilities Corporation	2020

Power sold under long-term contracts is as follows:

	Type of contract	With	Expires
Coolidge	Power sold under a 20-year PPA	Salt River Project Agricultural Improvements & Power District	2031

Earnings in the Western Power business are maximized by maintaining and optimizing the operations of our power plants, and through various marketing activities.

A disciplined operational strategy is critical to maximizing output and revenue at our cogeneration facilities and maximizing Coolidge earnings, where revenue is based on plant availability, and is not a function of market price.

The marketing function is critical for optimizing returns and managing risk through direct sales to medium and large industrial and commercial companies and other market participants. Our marketing group sells power sourced through the PPAs, markets uncommitted volumes from the cogeneration plants, and buys and sells power and natural gas to maximize earnings from our assets. To reduce exposure associated with uncontracted volumes, we sell a portion of our power in forward sales markets when acceptable contract terms are available.

A portion of our power is retained to be sold in the spot market or under shorter-term forward arrangements. This ensures we have adequate power supply to fulfill our sales obligations if we have unexpected plant outages and provides the opportunity to increase earnings in periods of high spot prices.

The amount sold forward will vary depending on market conditions and market liquidity and has historically ranged between 25 to 75 per cent of expected future production with a higher proportion being hedged in the near term periods. Such forward sales may be completed with medium to large industrial and commercial companies as well as other market participants and will affect our average realized price (versus spot price) in future periods.

Eastern Power
We own or are developing approximately 3,000 MW of power generation capacity in eastern Canada. All of the power produced by these assets is sold under long-term contracts.

Disciplined maintenance of plant operations is critical to the results of our Eastern Power assets, where earnings are based on plant availability and performance.

Assets currently operating under long-term contracts are as follows:

	Type of contract	With	Expires
Bécancour[1]	20-year PPA Steam sold to an industrial customer	Hydro-Québec	2026
Cartier Wind	20-year PPA	Hydro-Québec	2032
Grandview	20-year tolling agreement to buy 100 per cent of heat and electricity output	Irving Oil	2025
Halton Hills	20-year Clean Energy Supply contract	IESO	2030
Portlands Energy	20-year Clean Energy Supply contract	IESO	2029
Ontario Solar[2]	20-year Feed-in Tariff (FIT) contracts	IESO	2032-2034

1 Power generation has been suspended since 2008. We continue to receive capacity payments while generation is suspended.

2 We acquired four facilities in 2013 and an additional four facilities in 2014.

Assets currently under construction are as follows:

	Type of contract	With	Expires
Napanee	20-year Clean Energy Supply contract	IESO	20 years from in-service date

Western and Eastern Power results

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 24 for more information.

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Revenue[1]			
Western Power	**736**	605	644
Eastern Power[2]	**428**	400	415
Other[3]	**85**	108	91
	1,249	1,113	1,150
Income from equity investments[4]	**45**	141	68
Commodity purchases resold	**(404)**	(283)	(286)
Plant operating costs and other	**(299)**	(298)	(266)
Sundance A PPA arbitration decision	**-**	-	(30)
Exclude risk management activities[1]	**11**	4	(4)
Comparable EBITDA	**602**	677	632
Comparable depreciation and amortization	**(179)**	(172)	(152)
Comparable EBIT	**423**	505	480
Breakdown of comparable EBITDA			
Western Power	**252**	355	311
Eastern Power	**350**	322	321
Comparable EBITDA	**602**	677	632

1 The realized and unrealized gains and losses from financial derivatives used to manage Canadian Power's assets are presented on a net basis in Western and Eastern Power revenues. The unrealized gains and losses from financial derivatives included in Revenue are excluded to arrive at Comparable EBITDA.

2 Includes four solar facilities acquired between June and December 2013, three solar facilities acquired in September 2014, one solar facility acquired in December 2014 and Cartier Wind phase two of Gros-Morne completed in November 2012.

3 Includes Revenue from the sale of unused natural gas transportation, sale of excess natural gas purchased for generation and Cancarb sales of thermal carbon black up to April 15, 2014 when it was sold.

4 Includes our share of equity income from our investments in ASTC Power Partnership, which holds the Sundance B PPA, and Portlands Energy. Equity income does not include any earnings related to our risk management activities.

Sales volumes and plant availability
Includes our share of volumes from our equity investments.

year ended December 31	2014	2013	2012
Sales volumes (GWh)			
Supply			
Generation			
Western Power	**2,517**	2,728	2,691
Eastern Power[1]	**3,080**	3,822	4,384
Purchased			
Sundance A & B and Sheerness PPAs and other[2]	**11,472**	8,223	6,906
Other purchases	**16**	13	46
	17,085	14,786	14,027
Sales			
Contracted			
Western Power	**10,484**	7,864	8,240
Eastern Power[1]	**3,080**	3,822	4,384
Spot			
Western Power	**3,521**	3,100	1,403
	17,085	14,786	14,027
Plant availability[3]			
Western Power[4]	**96%**	95%	96%
Eastern Power[1,5]	**91%**	90%	90%

1 Includes four solar facilities acquired between June and December 2013, three solar facilities acquired in September 2014, and one solar facility acquired in December 2014 and Cartier Wind phase two of Gros-Morne completed in November 2012.

2 Includes our 50 per cent ownership interest of Sundance B volumes through the ASTC Power Partnership. Sundance A Unit 1 returned to service in September 2013 and Unit 2 returned to service in October 2013.

3 The percentage of time in a period that the plant is available to generate power, regardless of whether it is running.

4 Does not include facilities that provide power to us under PPAs.

5 Does not include Bécancour because power generation has been suspended since 2008.

Western Power
Western Power's comparable EBITDA in 2014 was $103 million lower than in 2013, due to the net effect of:

- lower realized power prices
- incremental earnings from the return to service of the Sundance A PPA Unit 1 in September 2013 and Unit 2 in October 2013 which also resulted in increased volume purchases
- sale of Cancarb in April 2014.

Average spot market power prices in Alberta decreased by 38% from approximately $80/MWh in 2013 to approximately $50/MWh in 2014. Despite strong power demand growth of just over three per cent, ten of the twelve months of 2014 saw relatively soft price levels as the Alberta power market was well supplied during the year. Weather events in February 2014 and July 2014 tightened the supply demand balance resulting in strong prices during those months. Realized power prices on power sales can be higher or lower than spot market power prices in any given period as a result of contracting activities.

In 2013, Western Power's comparable EBITDA was $44 million higher than 2012. The increase was mainly due to higher purchased volumes under the PPAs following the return to service of Sundance A Units 1 and 2.

Approximately 75 per cent of Western Power sales volumes were sold under contract in 2014 compared to 72 per cent in 2013 and 85 per cent in 2012.

Eastern Power
Eastern Power's comparable EBITDA in 2014 was $28 million higher than 2013 due to the net effect of incremental earnings from the four solar facilities acquired in 2013, the additional four facilities acquired in late 2014 and higher contractual earnings at Bécancour.

In 2013, Eastern Power's comparable EBITDA was similar to 2012 due to the net effect of incremental earnings from Cartier Wind and from the four solar facilities acquired in 2013 and lower contractual earnings at Bécancour.

Bruce Power

Bruce Power is a nuclear power generation facility located near Tiverton, Ontario and is comprised of Bruce A and Bruce B. Bruce A Units 1 to 4 have a combined capacity of approximately 3,000 MW and Bruce B Units 5 to 8 have a combined capacity of approximately 3,300 MW. Bruce B leases the eight nuclear reactors from Ontario Power Generation and subleases Units 1 to 4 to Bruce A.

Results from Bruce Power fluctuate primarily due to the frequency, scope and duration of planned and unplanned outages.

Under a contract with the IESO, all of the output from Bruce A is sold at a fixed price/MWh which is adjusted annually on April 1 for inflation and other provisions under the contract. Bruce A also recovers fuel costs from the IESO.

Bruce A fixed price	Per MWh
April 1, 2014 – March 31, 2015	$71.70
April 1, 2013 – March 31, 2014	$70.99
April 1, 2012 – March 31, 2013	$68.23

Under the same contract, all output from Bruce B Units 5 to 8 is subject to a floor price adjusted annually for inflation on April 1.

Bruce B floor price	Per MWh
April 1, 2014 – March 31, 2015	$52.86
April 1, 2013 – March 31, 2014	$52.34
April 1, 2012 – March 31, 2013	$51.62

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the average spot price in a month exceeds the floor price. The first quarter 2014 average spot price exceeded the floor price; however, spot prices fell below the floor price for the remainder of 2014. As a result, Bruce B recognized annual revenues at the floor price throughout 2014 and amounts received above the floor price in first quarter 2014 were repaid to the IESO in January 2015.

Bruce B also enters into fixed-price contracts under which it receives or pays the difference between the contract price and the spot price.

The contract also provides for payment if the IESO reduces Bruce Power's generation to balance the supply of and demand for electricity and/or manage other operating conditions of the Ontario power grid. The amount of the reduction is considered "deemed generation", for which Bruce Power is paid the fixed price, floor price or spot price as applicable under the contract.

Bruce Power results
Our proportionate share

year ended December 31 (millions of $, unless otherwise indicated)	**2014**	**2013**	**2012**
Income/(loss) from equity investments[1]			
Bruce A	**209**	202	(149)
Bruce B	**105**	108	163
	314	310	14
Comprised of:			
Revenues	**1,256**	1,258	763
Operating expenses	**(623)**	(618)	(567)
Depreciation and other	**(319)**	(330)	(182)
	314	310	14
Bruce Power – other information			
Plant availability[2]			
Bruce A[3]	**82%**	82%	54%
Bruce B	**90%**	89%	95%
Combined Bruce Power	**86%**	86%	81%
Planned outage days			
Bruce A	**118**	123	336
Bruce B	**127**	140	46
Unplanned outage days			
Bruce A	**123**	63	18
Bruce B	**4**	20	25
Sales volumes (GWh)[1]			
Bruce A[3]	**10,526**	10,458	4,194
Bruce B	**8,197**	8,010	8,598
	18,723	18,468	12,792
Realized sales price per MWh[4]			
Bruce A	**$72**	$70	$68
Bruce B	**$56**	$54	$55
Combined Bruce Power	**$63**	$62	$57

1 Represents our 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B. Sales volumes include deemed generation.

2 The percentage of time in a year the plant is available to generate power, regardless of whether it is running.

3 Plant availability and sales volumes include the incremental impact of Unit 1 and Unit 2 which were returned to service in October 2012.

4 Calculation based on actual and deemed generation. Bruce B realized sales prices per MWh includes revenues under the floor price mechanism and revenues from contract settlements.

Equity income from Bruce A in 2014 was $7 million higher than 2013. The increase was mainly due to lower depreciation and operating expenses and higher volumes partially offset by recognition of an insurance recovery of approximately $40 million in the first quarter 2013. The negative impact of increased outage days in 2014 is offset by higher generation levels while operating.

Equity income from Bruce B in 2014 was $3 million lower than 2013. The decrease was mainly due to higher lease expense recognized based on the terms of the lease agreement with Ontario Power Generation, partially offset by higher volumes and lower operating costs resulting from lower outage days.

In 2013, equity income from Bruce A was $351 million higher than 2012. The increase was mainly due to:

- incremental earnings from Units 1 and 2 which returned to service in October 2012
- higher incremental earnings from Unit 3 due to the West Shift Plus planned outage during first and second quarter 2012
- recognition in first quarter 2013 of an insurance recovery of approximately $40 million related to the May 2012 Unit 2 electrical generator failure that impacted Bruce A in 2012 and 2013
- higher incremental earnings from Unit 4 due to the planned life extension outage which began in third quarter 2012 and was completed in April 2013.

In 2013, equity income from Bruce B was $55 million lower than 2012. The decrease was mainly due to lower volumes and higher operating costs resulting from higher planned outage days.

U.S. Power

We own approximately 3,800 MW of power generation capacity in New York and New England, including plants powered by natural gas, oil, hydro and wind.

We earn revenues in both New York and New England in two ways – by providing capacity and by selling energy. Capacity markets compensate power suppliers for being available to provide power, and are intended to promote investment in new and existing power resources needed to meet customer demand and maintain a reliable power system. The energy markets compensate power providers for the actual energy they supply.

Providing capacity

Capacity revenues in New York and New England are a function of two factors – capacity prices and plant availability. It is important for us to keep our plant availability high to maximize the amount of capacity for which we get paid.

Capacity prices paid to capacity suppliers in New York are determined by a series of voluntary forward auctions and a mandatory spot auction. The forward auctions are bid based while the mandatory spot auction is affected by a demand curve price setting process that is driven by a number of established parameters that are subject to periodic review by the New York ISO and FERC. The parameters are determined for each zone and include the forecasted cost of a new unit entering the market, available existing operable supply and fluctuations in the forecasted demand.

The price paid for capacity in the New England Power Pool is determined by annual competitive auctions which are held three years in advance of the applicable capacity year. Auction results are impacted by actual and projected power demand, power supply, and other factors.

Selling energy

We focus on selling power under short and long-term contracts to wholesale, commercial and industrial customers in the following power markets:

- New York, operated by the New York ISO
- New England, operated by the New England ISO
- PJM Interconnection area (PJM).

We also earn additional revenues by bundling power sales with other energy services.

We meet our power sales commitments using power we generate ourselves or with power we buy at fixed prices, reducing our exposure to changes in commodity prices.

U.S. Power results

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 24 for more information.

year ended December 31 (millions of US$)	**2014**	**2013**	**2012**
Revenue			
Power[1]	**1,794**	1,587	1,240
Capacity	**362**	295	234
	2,156	1,882	1,474
Commodity purchases resold	**(1,297)**	(1,003)	(765)
Plant operating costs and other[2]	**(529)**	(509)	(500)
Exclude risk management activities[1]	**46**	(47)	-
Comparable EBITDA	**376**	323	209
Comparable depreciation and amortization	**(107)**	(107)	(121)
Comparable EBIT	**269**	216	88

1 The realized and unrealized gains and losses from financial derivatives used to manage U.S. Power's assets are presented on a net basis in power revenues. The unrealized gains and losses from financial derivatives included in Revenue are excluded to arrive at Comparable EBITDA.

2 Includes the costs of fuel consumed in generation.

Sales volumes and plant availability

year ended December 31	**2014**	**2013**	**2012**
Physical sales volumes (GWh)			
Supply			
Generation	**7,742**	6,173	7,567
Purchased	**10,822**	9,001	9,408
	18,564	15,174	16,975
Plant availability[1]	**82%**	84%	85%

1 The percentage of time the plant was available to generate power, regardless of whether it is running.

U.S. Power – other information

year ended December 31	**2014**	**2013**	**2012**
Average Spot Power Prices (US$ per MWh)			
New England	**65**	57	36
New York	**58**	52	39
Average New York Zone J Spot Capacity Prices (US$ per KW-M)	**14**	11	8

U.S. Power's comparable EBITDA in 2014 was US$53 million higher than 2013. This reflected the net effect of:

- higher realized capacity prices primarily in New York
- higher realized power prices for the New England and New York facilities
- higher generation volumes primarily at the Ravenswood facility
- higher prices and related costs on increased volumes purchased to fulfill power sales commitments to wholesale, commercial and industrial customers.

In 2013, U.S. Power's comparable EBITDA was US$114 million higher than 2012. This reflected the net effect of:

- higher realized capacity prices in New York
- higher realized power prices partially offset by the impact of higher fuel costs
- higher revenues and certain adjustments on sales to wholesale, commercial and industrial customers.

Average New York Zone J spot capacity prices were approximately 27 per cent higher in 2014 than in 2013. The increase in spot prices and the impact of hedging activities resulted in higher realized capacity prices in New York in 2014.

Wholesale electricity prices in New York and New England were higher in 2014 compared to 2013 primarily due to colder winter temperatures and gas transmission constraints. This resulted in higher natural gas prices in the predominantly gas-fired New England and New York power markets in first quarter 2014 compared to the same period in 2013. Average spot power prices in 2014 in New England increased approximately 14 per cent and in New York spot power prices increased approximately 11 per cent compared to 2013.

Physical sales volumes in 2014 rose compared to 2013. Generation volumes increased primarily due to higher generation at the Ravenswood facility throughout 2014 compared to 2013. Purchased volumes were also higher in 2014 compared to 2013 due to increased sales to commercial and industrial customers in both the New England and PJM markets.

As at December 31, 2014, approximately 3,700 GWh or 30 per cent of U.S. Power's planned generation is contracted for 2015, and 1,600 GWh or 14 per cent for 2016. 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

We own and operate 118 Bcf of non-regulated natural gas storage capacity in Alberta. This business operates independently from our regulated natural gas transmission business and from ANR's regulated storage business, which are included in our Natural Gas Pipelines segment.

Storage capacity

year ended December 31, 2014	Working gas storage capacity (Bcf)	Maximum injection/ withdrawal capacity (MMcf/d)
Edson	50	725
CrossAlta	68	550
	118	1,275

We also hold a contract for Alberta-based storage capacity with a third party.

Our natural gas storage business 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. Market volatility creates arbitrage opportunities and our natural gas storage facilities also give customers the ability to capture value from short-term price movements. The natural gas storage business is affected by the change in seasonal natural gas price spreads which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons.

Our gas storage business contracts with third parties, typically participants in the Alberta and interconnected gas markets, for a fixed fee to provide gas storage services on a short, medium, and/or long term basis.

We also enter into proprietary natural gas storage transactions, which include a forward purchase of our own 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, we lock in future positive margins, effectively eliminating our exposure to changes in gas prices.

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 through net income based on the forward market prices for the contracted month of delivery. We record changes in the fair value of these contracts in revenues. We do not include changes in the fair value of natural gas forward purchase and sales

contracts when we calculate comparable earnings because they do not represent the amounts that will be realized on settlement.

Natural Gas Storage and other results

Comparable EBITDA in 2014 was $19 million lower than 2013, mainly due to decreased third party storage revenue as a result of lower realized natural gas storage price spreads.

In 2013, comparable EBITDA was $4 million lower than 2012, mainly due to lower realized natural gas storage price spreads, partially offset by incremental earnings from CrossAlta resulting from the acquisition of the remaining 40 per cent interest in December 2012.

SIGNIFICANT EVENTS

Canadian Power

Ontario Solar

As part of a purchase agreement with Canadian Solar Solutions Inc. signed in 2011, we completed the acquisition of three Ontario solar facilities for $181 million in September 2014 and acquired a fourth facility for $60 million in December 2014. In 2013, we completed the acquisition of four solar facilities for $216 million. Our total investment in the eight solar facilities is $457 million. All power produced by the solar facilities is sold under 20-year FIT contracts with the IESO.

Napanee

In January 2015, we began construction activities of a 900 MW natural gas-fired power plant at Ontario Power Generation's Lennox site in eastern Ontario in the town of Greater Napanee. We expect to invest approximately $1.0 billion in the Napanee facility during construction and commercial operations are expected to begin in late 2017 or early 2018. Production from the facility is fully contracted with the IESO.

Bécancour

In May 2014, Hydro-Québec exercised its option in the amended suspension agreement to extend suspension of all electricity generation to the end of 2017, and requested further suspension of generation to the end of 2018. Under the December 2013 amended suspension agreement, Hydro-Québec has the option each year to further extend the suspension by an additional year (subject to certain conditions). We continue to receive capacity payments while generation is suspended.

Cancarb Limited and Cancarb Waste Heat Facility

The sale of Cancarb Limited, a thermal carbon black facility, and its related power generation facility closed in April 2014 for gross proceeds of $190 million. We recognized a gain of $99 million, net of tax, in second quarter 2014.

Bruce Power

In March 2014, Cameco Corporation sold its 31.6 per cent limited partnership interest in Bruce B to BPC Generation Infrastructure Trust (BPC). We are considering our option to increase our Bruce B ownership percentage.

New Canadian federal legislation is expected to come into force in 2015 respecting the determination of liability and compensation for a nuclear incident in Canada resulting in personal injuries and damages. This proposed legislation will replace existing legislation which currently provides that the licensed operator of a nuclear facility has absolute and exclusive liability and limits the liability to a maximum of $75 million. The proposed new law is fundamentally consistent with the existing regime although the maximum liability will increase to $650 million and increase in increments over three years to a maximum of $1 billion. The operator will also be required to maintain financial assurances such as insurance in the amount of the maximum liability. Our indirect subsidiary owns one-third of the shares of Bruce Power Inc., the licensed operator of Bruce Power, and as such Bruce Power is subject to this liability in the event of an incident and the legislation's other requirements.

U.S. Power

Ravenswood
In late September 2014, the 972 MW Unit 30 at the Ravenswood Generating Station experienced an unplanned outage as a result of a problem with the generator associated with the high pressure turbine. Insurance is expected to cover the repair costs and lost revenues associated with the unplanned outage, which are yet to be finalized. As a result of the expected insurance recoveries, net of deductibles, the Unit 30 unplanned outage is not expected to have a significant impact on our earnings although the recording of earnings may not coincide with lost revenues due to timing of the anticipated insurance proceeds. The unit is expected to be back in service in first half 2015.

Natural Gas Storage
Effective April 30, 2014, we terminated a 38 Bcf long-term natural gas storage contract in Alberta with Niska Gas Storage. The contract contained provisions allowing for possible early termination. As a result, we recorded an after tax charge of $32 million in 2014. We have re-contracted for new natural gas storage services in Alberta with Niska Gas Storage starting May 1, 2014 for a six-year period and a reduced average volume.

BUSINESS RISKS
The following are risks specific to our energy business. See page 99 for information about general risks that affect the company as a whole,including other operational risks, health, safety and environment (HSE) risks, and financial risks.

Fluctuating power and natural gas market prices
Power and natural gas prices are affected by fluctuations in supply and demand, weather, and by general economic conditions. The power generation facilities in our Western Power operations in Alberta, and in our U.S. Power operations in New England and New York, are exposed to commodity price volatility.

Earnings from these businesses are generally correlated to the prevailing power supply and demand conditions. In New England and New York, the price of natural gas also has a significant impact on power prices, as energy prices in these markets are usually set by gas-fired power supplies. Extended periods of low gas prices will generally exert downward pressure on power prices and therefore on earnings from our New England and New York facilities.

Our Coolidge Generating Station and our portfolio of assets in eastern Canada are fully contracted, and are therefore not subject to fluctuating commodity prices. As these contracts expire in the long term, it is uncertain if we will be able to re-contract on similar terms. Bruce Power's exposure to fluctuating power prices is discussed further below.

To mitigate the impact of power price volatility in Alberta and the U.S. northeast, we sell a portion of our supply under medium to long-term sales contracts where contract terms are acceptable. A portion of our power is retained to be sold in the spot market or under shorter-term forward arrangements to ensure we have adequate power supply to fulfill sales obligations if unexpected plant outages occur. This unsold supply 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 IESO, Bruce B volumes are subject to a floor price mechanism. When the spot market price is above the floor price, Bruce B's 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 IESO.

Our natural gas storage business is subject to fluctuating seasonal natural gas price spreads which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons.

U.S. Power capacity payments

A significant portion of revenues earned by Ravenswood and a portion of revenues earned by our power facilities in New England are driven by capacity payments. Fluctuations in capacity prices can have a material impact on these businesses, particularly in New York. New York capacity prices are determined by a series of voluntary forward auctions and a mandatory spot auction. The forward auctions are bid based while the mandatory spot auction is affected by a demand curve price setting process that is driven by a number of established parameters that are subject to periodic review by the New York ISO and FERC. These parameters are determined for each capacity zone and include the forecasted cost of a new unit entering the market, available existing operable supply and fluctuations in forecasted demand. Capacity payments are also a function of plant availability which is discussed below.

Plant availability

Optimizing and maintaining plant availability is essential to the continued success of our Energy business. Unexpected outages or extended planned outages at our power plants can increase maintenance costs, lower plant output and sales revenue and lower capacity payments and margins. We may also have to buy power or natural gas on the spot market to meet our delivery obligations.

We manage this risk by investing in a highly skilled workforce, operating prudently, running comprehensive, risk-based preventive maintenance programs and making effective capital investments.

For facilities we do not operate, our purchase agreements include a financial remedy if a plant owner does not deliver as agreed. The Sundance and Sheerness PPAs, for example, require the producers to pay us market-based penalties if they cannot supply the amount of power we have agreed to purchase.

Regulatory

We operate in both regulated and deregulated power markets in both the United States and Canada. These markets are subject to various federal, state and provincial regulations in both countries. As power markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively affect us 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, cost allocations to generators and out-of-market actions taken by others to build excess generation, all of which negatively affect the price of power or capacity, or both. In addition, our development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedules and costs. We are an active participant in formal and informal regulatory proceedings and take legal action where required.

Weather

Significant changes in temperature and other weather events have many effects on our business, ranging from the impact on demand, availability and commodity prices, to efficiency and output capability. Extreme temperature and weather can affect market demand for power and natural gas and can lead to significant price volatility. Extreme weather can also restrict the availability of natural gas and power if demand is higher than supply. Seasonal changes in temperature can reduce the efficiency of our natural gas-fired power plants, and the amount of power they produce. Variable wind speeds affect earnings from our wind assets, and sun-light hours and intensity affects earnings from our solar assets.

Hydrology

Our hydroelectric power generation facilities in the northeastern U.S. are subject to hydrology risks that can impact the volume of water available for generation at these facilities including weather changes and events, local river management and potential dam failures at these plants or upstream facilities.

Competition

We face various competitive forces that impact our existing assets and prospects for growth. For instance, our existing power plants in deregulated markets will compete over time with new power capacity. New supply could come in several forms including supply that employs more efficient power generation technologies, additional supply from regional power transmission interconnections and new supply in the form of distributed generation. We also face competition from other power companies in the greenfield power plant development arena.

Corporate

OTHER INCOME STATEMENT ITEMS

The following are reconciliations and related analyses of our non-GAAP measures to the equivalent GAAP measures.

Interest expense

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Comparable interest on long-term debt			
(including interest on junior subordinated notes)			
Canadian dollar-denominated	**(443)**	(495)	(513)
U.S. dollar-denominated	**(854)**	(766)	(740)
Foreign exchange	**(90)**	(20)	-
	(1,387)	(1,281)	(1,253)
Other interest and amortization expense	**(70)**	10	(23)
Capitalized interest	**259**	287	300
Comparable interest expense	**(1,198)**	(984)	(976)
Specific item:			
NEB 2013 Decision – 2012	**-**	(1)	-
Interest expense	**(1,198)**	(985)	(976)

Comparable interest expense in 2014 was $214 million higher than in 2013 due to the net effect of:

- higher interest as a result of long term debt issues of:
  - US$1.25 billion in February 2014
  - US$1.25 billion in October 2013
  - US$500 million in July 2013
  - $750 million in July 2013
  - US$500 million in July 2013 by TC PipeLines, LP
- lower interest on account of Canadian and U.S. dollar denominated debt maturities
- higher foreign exchange on interest on U.S. dollar denominated debt
- higher carrying charges to shippers in 2014 on the positive TSA balance for Canadian Mainline
- lower capitalized interest due to the completion of the Gulf Coast extension of the Keystone Pipeline System in first quarter 2014, partially offset by higher capitalized interest primarily for Keystone XL.

Comparable interest expense in 2013 was $8 million higher than 2012 due to the net effect of:

- higher interest as a result of long term debt issues of:
  - US$1.25 billion in October 2013
  - US$500 million in July 2013
  - $750 million in July 2013
  - US$500 million in July 2013 by TC PipeLines, LP
  - US$750 million in January 2013
  - US$1.0 billion in August 2012
- lower interest on account of Canadian and U.S. dollar denominated debt maturities
- higher foreign exchange on interest on U.S. dollar denominated debt
- lower capitalized interest due to Bruce A Units 1 and 2 return to service in fourth quarter 2012, partially offset by increased capitalized interest on the Gulf Coast extension.

Interest income and other

year ended December 31 (millions of $)	2014	2013	2012
Comparable interest income and other	**112**	42	86
Specific items (pre-tax):			
NEB 2013 Decision – 2012	**-**	1	-
Risk management activities	**(21)**	(9)	(1)
Interest income and other	**91**	34	85

Comparable interest income and other in 2014 was $70 million higher than 2013. This was the net result of:

- increased AFUDC related to our rate-regulated projects, including Energy East Pipeline and our Mexico pipelines,
- offset by higher realized losses in 2014 compared to 2013 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- the impact of a fluctuating U.S. dollar on the translation of foreign currency denominated working capital.

In 2013, comparable interest income and other was $44 million lower than 2012. This decrease was mainly due to higher realized losses in 2013 compared to 2012 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and on translation of foreign denominated working capital.

Income tax expense

year ended December 31 (millions of $)	2014	2013	2012
Comparable income tax expense	**(859)**	(662)	(477)
Specific items:			
Cancarb gain on sale	**(9)**	-	-
Niska contract termination	**11**	-	-
Gas Pacifico/INNERGY gain on sale	**(1)**	-	-
NEB 2013 Decision – 2012	**-**	42	-
Part VI.I income tax adjustment	**-**	25	-
Sundance A PPA arbitration decision – 2011	**-**	-	5
Risk management activities	**27**	(16)	6
Income tax expense	**(831)**	(611)	(466)

Comparable income tax expense increased $197 million in 2014 compared to 2013 mainly because of higher pre-tax earnings in 2014, changes in the proportion of income earned between Canadian and foreign jurisdictions as well as higher flow-through taxes in 2014 on Canadian regulated pipelines.

Comparable income tax expense increased $185 million in 2013 compared to 2012 because of higher pre-tax earnings in 2013 combined with changes in the proportion of income earned between Canadian and foreign jurisdictions.

Other

year ended December 31 (millions of $)	2014	2013	2012
Net income attributable to non-controlling interests	**(153)**	(125)	(118)
Preferred share dividends	**(97)**	(74)	(55)

Net income attributable to non-controlling interests increased by $28 million in 2014 compared to 2013 primarily due to the sale of a 45 per cent interest in each of GTN and Bison to TC PipeLines, LP in July 2013 and the remaining 30 per cent of Bison in October 2014. This was partially offset by the redemption of Series U preferred shares in October 2013 and Series Y preferred shares in March 2014.

Net income attributable to non-controlling interest increased $7 million in 2013 compared to 2012 primarily due to the sale of a 45 per cent interest in each of GTN and Bison to TC PipeLines, LP in July 2013.

Preferred share dividends increased by $23 million in 2014 compared to 2013 due to the issuances of Series 7 preferred shares in March 2013 and Series 9 preferred shares in January 2014.

Preferred share dividends increased $19 million in 2013 compared to 2012 due to the issuance of Series 7 preferred shares in March 2013.

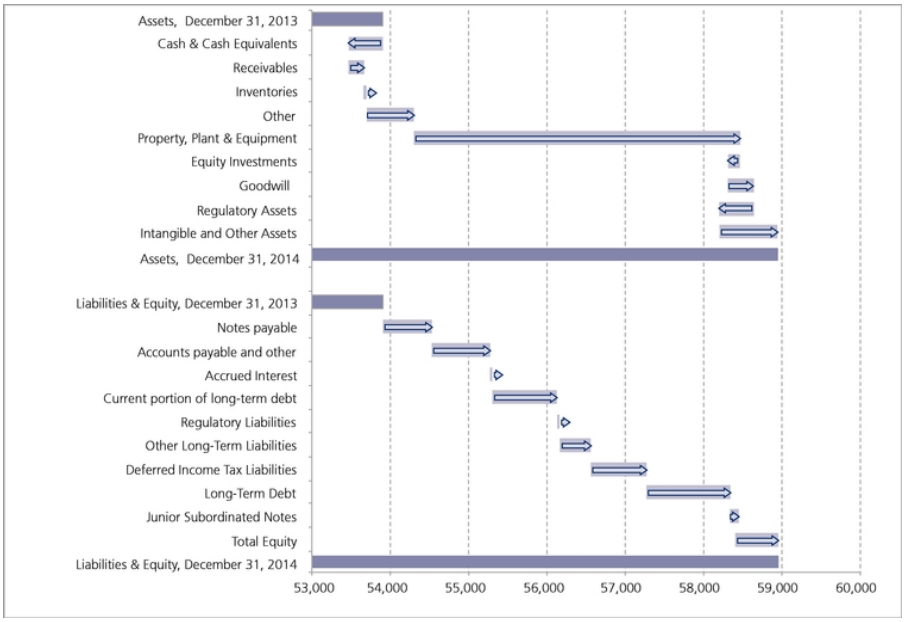
Financial condition

We strive to maintain strong financial capacity and flexibility in all parts of the economic cycle. We rely on our operating cash flow to sustain our business, pay dividends and fund a portion of our growth. In addition, we access capital markets to meet our financing needs, manage our capital structure and to preserve our credit ratings.

We believe we have the financial capacity to fund our existing capital program through our predictable cash flow from our operations, access to capital markets, proceeds from the sale of natural gas pipeline assets to TC PipeLines, LP, cash on hand and substantial committed credit facilities.

Balance sheet analysis

As of December 31, 2014, assets increased by $5.0 billion, liabilities increased by $4.5 billion and equity rose by $0.5 billion compared to December 31, 2013.



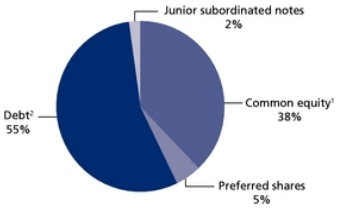
The increase in assets was primarily due to increases in property, plant and equipment and intangible and other assets. Property, plant and equipment increased by $4.2 billion primarily due to the completion of the Gulf Coast Extension of the Keystone Pipeline System, further investment in the NGTL System, investment in our Mexican pipelines projects, construction of the Houston Lateral and Tank Terminal and the expansion of our ANR pipeline. Intangible and other assets rose by $0.7 billion primarily due to spending on our capital projects under development.

The increase in liabilities was primarily due to an increase in long-term debt and notes payable used to fund our growth. In 2014, we issued $1.4 billion and repaid $1.1 billion of long term debt. The strengthening of the U.S. dollar also contributed a $1.6 billion increase on translation of our U.S. dollar-denominated debt. In 2014, notes payable increased by $0.6 billion.

Total equity increased $0.5 billion in 2014 mainly due to a $450 million preferred share issuance in January 2014.

Consolidated capital structure

at December 31, 2014



[1] Includes non-controlling interests in TC PipeLines, LP and Portland

[2] Net of cash and excluding junior subordinated notes

As at December 31, 2014, we had unused capacity of $1.55 billion, $2.0 billion and US$2.75 billion under our equity, Canadian debt and U.S. debt shelf prospectuses, respectively, to facilitate future access to the North American debt and equity markets.

As at December 31, 2014, we were in compliance with all of our financial covenants. Provisions of various trust indentures and credit arrangements with certain of our subsidiaries can restrict those subsidiaries' ability to declare and pay dividends or make distributions under certain circumstances. If such restrictions apply, they may, in turn, have an impact on our ability to declare and pay dividends on our common and preferred shares. In the opinion of management, these provisions do not currently restrict or alter our ability to declare or pay dividends. These trust indentures and credit arrangements also require us to comply with various affirmative and negative covenants and maintain certain financial ratios.

Cash flows

The following tables summarize the cash flows of our business.

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Net cash provided by operations	**4,079**	3,674	3,571
Net cash used in investing activities	**(4,144)**	(5,120)	(3,256)
(Deficiency)/surplus	**(65)**	(1,446)	315
Net cash (used in)/provided by financing activities	**(373)**	1,794	(403)
	(438)	348	(88)
Effect of foreign exchange rate changes on Cash and Cash Equivalents	**-**	28	(15)
Net change in Cash and Cash Equivalents	**(438)**	376	(103)

We continue to fund our extensive capital program through cash flow from operations supplemented by capital market financing activities and the sale of our U.S. natural gas pipeline assets to TC PipeLines, LP.

Liquidity will continue to be comprised of predictable cash flow generated from operations, committed credit facilities, our ability to access debt and equity markets in both Canada and the U.S., additional drop downs of our U.S. natural gas pipeline assets into TC PipeLines, LP and cash on hand.

Net cash provided by operations

year ended December 31 (millions of $)	2014	2013	2012
Funds generated from operations	**4,268**	4,000	3,284
(Increase)/decrease in operating working capital	**(189)**	(326)	287
Net cash provided by operations	**4,079**	3,674	3,571

Funds generated from operations, a non-GAAP measure, helps us assess the cash generating ability of our operations excluding the timing effects of working capital changes. See page 24 for more information about non-GAAP measures. The increase in 2014 compared to 2013 was driven by the increase in comparable earnings adjusted for the following non-cash items: increased deferred income tax expense and depreciation, higher equity AFUDC income and lower equity earnings. Funds generated from operations also reflected lower distributed earnings from equity investments.

At December 31, 2014, our current liabilities were higher than our current assets, leaving us with a working capital deficit of $4.0 billion. This short-term deficiency was mainly due to the use of accounts payable, notes payable and the current portion of our long-term debt to fund our capital program.

This short-term deficiency is considered to be in the normal course of a growing business and is managed through:

- our ability to generate cash flow from operations
- our access to capital markets
- approximately $5 billion of unutilized committed revolving bank lines.

Net cash used in investing activities

year ended December 31 (millions of $)	2014	2013	2012
Capital expenditures	**(3,550)**	(4,264)	(2,595)
Capital projects under development	**(807)**	(488)	(3)
Equity investments	**(256)**	(163)	(652)
Acquisitions, net of cash acquired	**(241)**	(216)	(214)
Proceeds from sale of assets, net of transaction costs	**196**	-	-
Deferred amounts and other	**514**	11	208
Net cash used in investing activities	**(4,144)**	(5,120)	(3,256)

Our 2014 capital spending was incurred primarily for expanding our NGTL System, construction of our Mexican pipelines, construction of the Houston Lateral and Tank Terminal, development of our Energy East Pipeline and expansion of the ANR pipeline. Also included in investing activities in 2014 was the acquisition of an additional four solar facilities in Ontario, proceeds from the sale of Cancarb and its related power generation facilities and our contribution for the construction of Grand Rapids Pipeline.

Net cash (used in)/provided by financing activities

year ended December 31 (millions of $)	2014	2013	2012
Long-term debt issued, net of issue costs	**1,403**	4,253	1,491
Long-term debt repaid	**(1,069)**	(1,286)	(980)
Notes payable issued/(repaid), net	**544**	(492)	449
Dividends and distributions paid	**(1,617)**	(1,522)	(1,416)
Common shares issued	**47**	72	53
Preferred shares issued, net of issue costs	**440**	585	-
Partnership units of subsidiary issued, net of issue costs	**79**	384	-
Preferred shares of subsidiary redeemed	**(200)**	(200)	-
Net cash (used in)/provided by financing activities	**(373)**	1,794	(403)

Long-term debt issued

(millions of $) Company	Issue date	Type	Maturity date	Amount	Interest Rate
TCPL	January 2015	Senior Unsecured Notes	January 2018	US$500	1.88%
	January 2015	Senior Unsecured Notes	January 2018	US$250	Floating
	February 2014	Senior Unsecured Notes	March 2034	US$1,250	4.63%
	October 2013	Senior Unsecured Notes	October 2023	US$625	3.75%
	October 2013	Senior Unsecured Notes	October 2043	US$625	5.00%
	July 2013	Senior Unsecured Notes	June 2016	US$500	Floating
	July 2013	Medium-Term Notes	July 2023	$450	3.69%
	July 2013	Medium-Term Notes	November 2041	$300	4.55%
	January 2013	Senior Unsecured Notes	January 2016	US$750	0.75%
	August 2012	Senior Unsecured Notes	August 2022	US$1,000	2.50%
	March 2012	Senior Unsecured Notes	March 2015	US$500	0.88%
TC PipeLines, LP	July 2013	Unsecured Term Loan Facility	July 2018	US$500	Floating

Long-term debt retired

(millions of $) Company	Retirement date	Type	Amount	Interest Rate
TCPL	January 2015	Senior Unsecured Notes	US$300	4.88%
	June 2014	Debentures	$125	11.10%
	February 2014	Medium-Term Notes	$300	5.05%
	January 2014	Medium-Term Notes	$450	5.65%
	August 2013	Senior Unsecured Notes	US$500	5.05%
	June 2013	Senior Unsecured Notes	US$350	4.00%
	May 2012	Senior Unsecured Notes	US$200	8.63%
Nova Gas Transmission Ltd.	June 2014	Debentures	$53	11.20%
	December 2012	Debentures	US$175	8.50%

Preferred share issuance, redemption and conversion

In January 2014, we completed a public offering of 18 million Series 9 cumulative redeemable first preferred shares at $25 per share resulting in gross proceeds of $450 million. Investors are entitled to receive fixed cumulative dividends at an annual rate of $1.0625 per share, payable quarterly. The dividend rate will reset on October 30, 2019 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 2.35 per cent. The preferred shares are redeemable by us on or after October 30, 2019 and on October 30 of every fifth year thereafter at a price of $25 per share plus accrued and unpaid dividends. Investors will have the right to convert their shares into Series 10 cumulative redeemable first preferred shares on October 30, 2019 and on October 30 of every fifth year thereafter. The holders of Series 10 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at an annualized rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 2.35 per cent.

In March 2014, we redeemed all four million Series Y preferred shares of TCPL at a price of $50 per share plus $0.2455 representing accrued and unpaid dividends. The total face value of the outstanding Series Y shares was $200 million and they carried an aggregate of $11 million in annualized dividends.

In December 2014, Series 1 shareholders elected to convert 12.5 million of our 22 million outstanding Series 1 cumulative redeemable first preferred shares, on a one-for-one basis into Series 2 floating-rate cumulative redeemable first preferred shares. The Series 1 shares will yield an annual fixed dividend rate of 3.266 per cent, paid on a quarterly basis, for the five-year period which began on December 31, 2014. The Series 2 shares will pay a floating quarterly dividend at an annualized rate equal to the sum of the 90-day Government of Canada treasury bill rate and 1.92 per cent for the five-year period which began on December 31, 2014. The floating quarterly dividend rate for the Series 2 shares for the first quarterly floating

rate period, commencing December 31, 2014, is 2.815 per cent per annum and will be reset each quarter going forward.

The net proceeds of the above debt and preferred share offerings were used for general corporate purposes and to reduce short-term indebtedness.

TC PipeLines, LP at-the-market (ATM) equity issuance program

In August 2014, TC PipeLines, LP initiated its at-the-market equity issuance program (ATM program) under which it is authorized to offer and sell common units having an aggregate offering price of up to US$200 million.

From August until December 31, 2014, 1.3 million common units were issued under the ATM program generating net proceeds of approximately US$73 million. Our ownership interest in TC PipeLines, LP will decrease as a result of equity issuances under the ATM program.

Credit facilities

We have committed, revolving credit facilities to primarily support our commercial paper programs. The commercial paper programs, along with additional demand credit facilities, are used for general corporate purposes, including issuing letters of credit and providing additional liquidity.

At December 31, 2014, we had $6.7 billion (2013 – $6.2 billion) in unsecured credit facilities, including:

Amount	Unused capacity	Subsidiary	For	Matures
$3 billion	$3 billion	TCPL	Committed, syndicated, revolving, extendible credit facility that supports TCPL's Canadian commercial paper program	December 2019
US$1 billion	US$1 billion	TransCanada PipeLine USA Ltd. (TCPL USA)	Committed, syndicated, revolving extendible, credit facility that is used for TCPL USA general corporate purposes	November 2015
US$1 billion	US$1 billion	TransCanada American Investments Ltd. (TAIL)	Committed, syndicated, revolving, extendible credit facility that supports the TAIL U.S. dollar commercial paper program in the U.S.	November 2015
$1.4 billion	$0.6 billion	TCPL/TCPL USA	Demand lines for issuing letters of credit and as a source of additional liquidity. At December 31, 2014, we had outstanding $0.8 billion in letters of credit under these lines.	Demand

At December 31, 2014, our operated affiliates had $0.4 billion of undrawn capacity on committed credit facilities.

Contractual obligations

Payments due (by period)

at December 31, 2014 (millions of $)	Total	less than 12 months	12 - 36 months	37 - 60 months	more than 60 months
Notes payable	2,467	2,467	-	-	-
Long-term debt (includes junior subordinated notes)	25,961	1,797	3,071	2,773	18,320
Operating leases (future payments for various premises, services and equipment, less sub-lease receipts)	1,694	300	575	432	387
Purchase obligations	4,221	2,201	1,251	453	316
Other long-term liabilities reflected on the balance sheet	416	8	17	19	372
	34,759	6,773	4,914	3,677	19,395

Our contractual obligations include our long-term debt, operating leases, purchase obligations and other liabilities incurred in our business such as environmental liability funds and employee retirement and post-retirement benefit plans.

Long-term debt

At the end of 2014, we had $25 billion of long-term debt and $1.2 billion of junior subordinated notes, compared to $22.9 billion of long-term debt and $1.1 billion of junior subordinated notes at December 31, 2013.

Total notes payable were $2.5 billion at the end of 2014 compared to $1.8 billion at the end of 2013.

We attempt to spread out the maturity profile of our debt. The majority of our debt obligations mature beyond five years with an average term of 12 years.

At December 31, 2014, scheduled principal repayments and interest payments related to our long-term debt were as follows:

Principal repayments

Payments due (by period)

at December 31, 2014 (millions of $)	Total	less than 12 months	12 - 36 months	37 - 60 months	more than 60 months
Notes payable	2,467	2,467	-	-	-
Long-term debt	24,801	1,797	3,071	2,773	17,160
Junior subordinated notes	1,160	-	-	-	1,160
	28,428	4,264	3,071	2,773	18,320

Interest payments

Payments due (by period)

at December 31, 2014 (millions of $)	Total	less than 12 months	12 - 36 months	37 - 60 months	more than 60 months
Long-term debt	17,878	1,328	2,467	2,226	11,857
Junior subordinated notes	3,867	74	147	147	3,499
	21,745	1,402	2,614	2,373	15,356

Operating leases

Our operating leases for premises, services and equipment expire at different times between now and 2052. Some of our operating leases include the option to renew the agreement for one to five years.

Our commitments under the Alberta PPAs are considered operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Fixed payments under these PPAs have been included in our summary of future obligations. Variable payments have been excluded as these payments are dependent upon plant availability and other factors. Our share of power purchased under the PPAs in 2014 was $391 million (2013 – $242 million; 2012 – $238 million).

Purchase obligations

We have purchase obligations that are transacted at market prices and in the normal course of business, including long-term natural gas transportation and purchase arrangements.

Capital expenditure commitments include obligations related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts.

Payments due (by period)[1]

at December 31, 2014 (millions of $)	Total	less than 12 months	12 - 36 months	37 - 60 months	more than 60 months
Natural Gas Pipelines					
Transportation by others[2]	346	94	171	64	17
Capital spending[3]	912	841	71	-	-
Other	6	2	4	-	-
Liquids Pipelines					
Capital spending[3]	1,784	908	651	225	-
Other	70	7	14	14	35
Energy					
Commodity purchases	308	163	125	20	-
Capital spending[3]	205	127	78	-	-
Other[4]	570	48	129	130	263
Corporate					
Information technology and other	20	11	8	-	1
	4,221	2,201	1,251	453	316

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

2 Demand rates are subject to change. The contractual obligations in the table are based on demand volumes only and exclude commodity charges incurred when volumes flow.

3 Amounts include capital expenditures and capital projects under development, are estimates and are subject to variability based on timing of construction and project enhancements.

4 Includes estimates of certain amounts which are subject to change depending on plant-fired hours, use of natural gas storage facilities, the consumer price index, actual plant maintenance costs, plant salaries as well as changes in regulated rates for transportation.

Outlook

We are developing quality projects under our long-term $46 billion capital program. These long-life infrastructure assets are supported by long-term commercial arrangements, and once completed, are expected to generate significant growth in earnings and cash flow.

Our $46 billion capital program is comprised of $12 billion of small to medium-sized, shorter-term projects and $34 billion of commercially secured large-scale, medium – and longer-term projects each of which are subject to key commercial or regulatory approvals. The portfolio is expected to be financed through our growing internally generated cash flow and a combination of funding options including:

- senior debt
- project financing
- preferred shares
- hybrid securities
- additional drop downs of our U.S. natural gas pipeline assets to TC PipeLines, LP
- asset sales
- potential involvement of strategic or financial partners
- portfolio management.

Additional financing alternatives available include common equity through DRP or, lastly, discrete equity issuances.

GUARANTEES

Bruce Power

We and our partner, BPC, have each severally guaranteed some of Bruce B's contingent financial obligations related to power sales agreements, a lease agreement and contractor services. The Bruce B guarantees have terms to 2018 except for one guarantee with no termination date that has no exposure associated with it.

We and BPC have each severally guaranteed half of certain contingent financial obligations of Bruce A related to a sublease agreement, an agreement with the IESO to restart the Bruce A power generation units, and certain other financial obligations. The Bruce A guarantees have terms to 2019.

At December 31, 2014, our share of the potential exposure under the Bruce A and B guarantees was estimated to be $634 million. The carrying amount of these guarantees was estimated to be $6 million. Our exposure under certain of these guarantees is unlimited.

Other jointly owned entities

We and our partners in certain other jointly owned entities have also guaranteed (jointly, severally, or jointly and severally) the financial performance of these entities relating mainly to redelivery of natural gas, PPA payments and the payment of liabilities. The guarantees have terms ranging to 2040.

Our share of the potential exposure under these assurances was estimated at December 31, 2014 to be a maximum of $104 million. The carrying amount of these guarantees was $14 million, and is included in other long-term liabilities. In some cases, if we make a payment that exceeds our ownership interest, the additional amount must be reimbursed by our partners.

OBLIGATIONS – PENSION AND OTHER POST-RETIREMENT PLANS

In 2015, we expect to make funding contributions of approximately $70 million for the defined benefit pension plans, approximately $7 million for the other post-retirement benefit plans and approximately $36 million for the savings plan and defined contribution pension plans. In addition, the Company expects to provide a $35 million letter of credit to the Canadian DB Plan for the funding of solvency requirements.

In 2014, we made funding contributions of $73 million to our defined benefit pension plans, $6 million for the other post-retirement benefit plans and $37 million for the savings plan and defined contribution pension plans. We also provided a $47 million letter of credit to a defined benefit plan in lieu of cash funding.

Outlook

The next actuarial valuation for our pension and other post-retirement benefit plans will be carried out as at January 1, 2015. Based on current market conditions, we expect funding requirements for these plans to approximate 2014 levels for several years. This will allow us to amortize solvency deficiencies in the plans, in addition to normal funding costs.

Our net benefit cost for our defined benefit and other post-retirement plans decreased to $115 million in 2014 from $134 million, mainly due to a higher discount rate used to measure the benefit obligation.

Future net benefit costs and the amount we will need to contribute to fund our plans will depend on a range of factors, including:

- interest rates
- actual returns on plan assets
- changes to actuarial assumptions and plan design
- actual plan experience versus projections
- amendments to pension plan regulations and legislation.

We do not expect future increases in the level of funding needed to maintain our plans to have a material impact on our liquidity.

Other information

RISKS AND RISK MANAGEMENT

The following is a summary of general risks that affect our company. You can find risks specific to each operating business segment in the business segment discussions.

Risk management is integral to the successful operation of our business. Our strategy is to ensure that our risks and related exposures are in line with our business objectives and risk tolerance.

We build risk assessment into our decision-making processes at all levels.

The Board's Governance Committee oversees our risk management activities, which includes ensuring that there are appropriate management systems in place to manage our risks, and adequate Board oversight of our risk management policies, programs and practices. Other Board committees oversee specific types of risk: the Audit Committee oversees management's role in monitoring financial risk, the Human Resources Committee oversees executive resourcing and compensation, organizational capabilities and compensation risk, and the Health, Safety and Environment Committee oversees operational, safety and environmental risk through regular reporting from management.

Our executive leadership team is accountable for developing and implementing risk management plans and actions, and effective risk management is reflected in their compensation.

Operational risks

Risk and Description	Impact	Monitoring and Mitigation
Business interruption		
Operational risks, including labour disputes, equipment malfunctions or breakdowns, acts of terror, or natural disasters and other catastrophic events.	Decrease in revenues, increase in operating costs or legal proceedings or other expenses all of which could reduce our earnings. Losses not covered by insurance could have an adverse effect on operations, cash flow and financial position.	We have incident, emergency and crisis management systems to ensure an effective response to minimize further loss or injuries and to enhance our ability to resume operations. We also have a Business Continuity Program that determines critical business processes and develops resumption plans to ensure process continuity. We have comprehensive insurance to mitigate certain of these risks, but insurance does not cover all events in all circumstances.
Reputation and relationships		
Our reputation and relationship with our stakeholders, such as Aboriginal communities, other communities, landowners, governments and government agencies, and environmental non-governmental organizations is very important.	These stakeholders can have a significant impact on our operations, infrastructure development and overall reputation.	Our Stakeholder Engagement Framework is our formal commitment to stakeholder engagement. Our four core values – integrity, collaboration, responsibility and innovation – are at the heart of our commitment to stakeholder engagement, and guide us in our interactions with stakeholders.
Execution and capital costs		
Investing in large infrastructure projects involves substantial capital commitments and associated execution risks based on the assumption that these assets will deliver an attractive return on investment in the future.	While we carefully consider the expected cost of our capital projects, under some contracts we bear capital cost overrun risk which may decrease our return on these projects.	Under some contracts, we share the cost of execution risks with customers, in exchange for the potential benefit they will realize when the project is finished.

Risk and Description	Impact	Monitoring and Mitigation
Cyber security		
We rely on our information technology to process, transmit and store electronic information, including information we use to safely operate our assets.	A breach in the security of our information technology could expose our business to a risk of loss, misuse or interruption of critical information and functions. This could affect our operations, damage our assets, result in safety incidents, damage to the environment, reputational harm, competitive disadvantage, regulatory enforcement actions and potential litigation, which could have a material adverse effect on our operations, financial position and results of operations.	We have a comprehensive cyber security strategy which aligns with industry and recognized standards for cyber security. This strategy includes cyber security risk assessments, continuous monitoring of networks and other information sources for threats to the organization, comprehensive incident response plans/processes and a cyber security awareness program for employees.

Pipeline abandonment costs
The NEB's Land Matters Consultation Initiative (LMCI) is an initiative that requires all Canadian pipeline companies regulated by the NEB to set aside funds to cover future pipeline abandonment costs.

The NEB provided several key guiding principles under this initiative, including the position that abandonment costs are a legitimate cost of providing pipeline service and are recoverable, upon NEB approval, from users of the individual pipeline systems. Pipeline companies are responsible for managing the collection and investment of funds to cover future abandonment costs.

All hearings have been completed and Board decisions have been received, with the final decision in December 2014, providing approval to begin collection through an abandonment surcharge in January 2015. Collection of funds will be held in trusts which will serve to hold and invest funds collected to cover future abandonment costs.

Health, safety and environment
The Health, Safety and Environment committee of TransCanada's Board of Directors (the Board) monitors compliance with our HSE corporate commitment statement through regular reporting from management. We have an integrated HSE Management System that is used to capture, organize and document our related policies, programs and procedures.

The HSE Management System is modeled after international standards, conforms to external industry consensus standards and voluntary programs, and complies with applicable legislative requirements and various other internal management systems. It follows a continuous improvement cycle.

The committee reviews HSE performance and operational risk management on a quarterly basis. It receives detailed reports on:

- overall HSE corporate governance
- operational performance and preventive maintenance metrics
- asset integrity programs
- emergency preparedness, incident response and evaluation
- people and process safety performance metrics
- developments in and compliance with applicable legislation and regulations.

The committee also receives updates on any specific areas of operational and construction risk management review being conducted by management and the results and corrective action plans emanating from internal and third party audits.

The safety and integrity of our existing and newly-developed infrastructure is a top priority. All 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. In 2014, we spent $550 million for pipeline integrity on the natural gas and liquids pipelines we operate, an increase of $174 million over 2013 primarily

due to increased levels of in-line pipeline inspections and related maintenance projects on all systems as well an increased amount of pipe replacement required due to population encroachment on the pipelines. Under the approved regulatory models in Canada, non-capital pipeline integrity expenditures on NEB-regulated pipelines are generally treated on a flow-through basis and, as a result, these expenditures have minimal impact on our earnings. Under the Keystone contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, these expenditures generally have no impact on our earnings. Our safety record in 2014 continued to meet or exceed industry benchmarks.

Our Energy operations spending associated with process safety and our various integrity programs is used to minimize risk to employees and the public, process equipment, the surrounding environment, and to prevent disruptions to serving the electrical needs of our customers, within the footprint of each facility.

Spending associated with public safety on Energy assets is focused primarily on our hydro dams and associated equipment.

Our main environmental risks are:

- air and GHG emissions
- product releases, including crude oil and natural gas, into the environment (land, water and air)
- use, storage and disposal of chemicals and hazardous materials
- compliance with corporate and regulatory policies and requirements and new regulations.

As described in the Business interruption section, above, we have a set of procedures in place to manage our response to natural disasters which include catastrophic events such as forest fires, tornadoes, earthquakes, floods, volcanic eruptions and hurricanes. The procedures, which are included in our Incident Management Program, are designed to help protect the health and safety of our employees, minimize risk to the public and limit any operational impacts caused by a natural disaster on the environment.

Environmental compliance and liabilities
Our facilities are subject to federal, state, provincial and local environmental statutes and regulations governing environmental protection, including air and GHG emissions, water quality, wastewater discharges and waste management. Our facilities are required to obtain and comply with a wide variety of environmental registrations, licenses, permits and other approvals and requirements. Failure to comply could result in administrative, civil or criminal penalties, remedial requirements or orders affecting future operations.

We continually monitor our facilities to ensure compliance with all environmental requirements. We routinely monitor proposed changes in environmental policy, legislation and regulation, and where the risks are potentially large or uncertain, we comment on proposals independently or through industry associations.

We are not aware of any material outstanding orders, claims or lawsuits against us related to releasing or discharging any material into the environment or in connection with environmental protection.

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 to estimate the amount and timing of all our future expenditures related to environmental matters because:

- environmental laws and regulations (and interpretation and enforcement of them) can change
- new claims can be brought against our existing or discontinued assets
- our pollution control and clean up cost estimates may change, especially when our current estimates are based on preliminary site investigation or agreements
- we may find new contaminated sites, or what we know about existing sites could change

- where there is potentially more than one responsible party involved in litigation, we cannot estimate our joint and several liability with certainty.

At December 31, 2014, we had accrued approximately $30 million related to these obligations ($32 million at the end of 2013). This represents the amount that we have estimated that we will need to manage our currently known environmental liabilities. We believe that we have 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. We adjust this reserve quarterly to account for changes in liabilities.

Greenhouse gas emissions regulation risk
We own assets and have business interests in a number of regions where there are regulations to address industrial GHG emissions. We have procedures in place to comply with these regulations, including:

- under the Specified Gas Emitters Regulation in Alberta, established industrial facilities with GHG emissions above a certain threshold have had to reduce their emissions by 12 per cent below an average intensity baseline since 2007. Our NGTL System facilities, Sundance and Sheerness are subject to this regulation. We recover compliance costs on the NGTL System through the tolls our customers pay. A portion of the compliance costs for Sundance and Sheerness are recovered through market pricing and contract flow through provisions. We recorded $38 million for the Alberta Specified Gas Emitters Regulation in 2014 (2013 – $25 million)
- B.C. has imposed a tax on carbon dioxide (CO_2) emissions from fossil fuel combustion since 2008. We recover the compliance costs for our compressor and meter stations through the tolls our customers pay. In 2014, we recorded $6 million (2013 – $6 million) for the B.C. carbon tax
- northeastern U.S. states that are members of the Regional Greenhouse Gas Initiative (RGGI) implemented a CO_2 cap-and-trade program for electricity generators beginning January 2009. This program applies to both the Ravenswood and Ocean State Power generation facilities. We recorded $9 million in 2014 (2013 – $6 million) to participate in quarterly auctions of allowances under RGGI
- Québec's *Regulation Respecting a Cap-and-Trade System for Greenhouse Gas Emission Allowances* came into force in December 2011 with significant amendments finalized in December 2012. Beginning in January 2013, Bécancour was required to cover its GHG emissions. As per the regulations, the government awarded free emission units for the majority of Bécancour's compliance requirements for 2013 and 2014. The remaining requirements were purchased through auctions. The cost of these emissions units is recovered through commercial contracts.The pipeline facilities in Québec are also covered under this regulation and have purchased compliance instruments. We recorded approximately $1 million for compliance with this regulation in 2014 (2013 – less than $1 million)
- in 2013, California implemented a cap and trade program that impacts electricity importers as well as a number of industrial emitters of GHG emissions. Our costs associated with the program were less than $1 million in 2014 (2013 – less than $1 million).

There are federal, regional, state and provincial initiatives currently in development. While economic events may continue to affect the scope and timing of new regulations, we anticipate that most of our facilities will be subject to future regulations to manage industrial GHG emissions.

Financial risks
We are exposed to market risk, counterparty credit risk and liquidity risk, and have strategies, policies and limits in place to mitigate their impact on our earnings, cash flow and, ultimately, shareholder value.

These strategies, policies and limits are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance. We manage market risk and counterparty credit risk within limits that are ultimately established by the Board, implemented by senior management and monitored by our risk management and internal audit groups. Management monitors compliance with market and counterparty risk management policies and procedures, and reviews the adequacy of the risk management framework, overseen by the Audit Committee. Our internal audit group assists the Audit Committee by carrying out regular and ad-hoc reviews of risk management controls and procedures, and reporting up to the Audit Committee.

Market risk
We build and invest in energy infrastructure projects, buy and sell energy commodities, issue short-term and long-term debt (including amounts in foreign currencies) and invest in foreign operations. Certain of these activities expose us to market risk from changes in commodity prices and foreign exchange and interest rates which may affect our earnings and the value of the financial instruments we hold.

We use derivative contracts to assist in managing our exposure to market risk, including:

- forwards and futures contracts – agreements to buy or sell a financial instrument or commodity at a specified price and date in the future. We use foreign exchange and commodity forwards and futures to manage the impact of changes in foreign exchange rates and commodity prices
- swaps – agreements between two parties to exchange streams of payments over time according to specified terms. We use interest rate, cross-currency and commodity swaps to manage the impact of changes in interest rates, foreign exchange rates and commodity prices
- options – agreements that give the purchaser the right (but not the obligation) 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. We use option agreements to manage the impact of changes in interest rates, foreign exchange rates and commodity prices.

We assess contracts we use to manage market risk to determine whether all, or a portion of it, meets the definition of a derivative.

Commodity price risk
We are exposed to changes in commodity prices, especially electricity and natural gas, which may affect our earnings. We use several strategies to reduce this exposure, including:

- committing a portion of expected power supply to fixed price sales contracts of varying terms while reserving a portion of our unsold power supply to mitigate operational and price risk in our asset portfolio
- purchasing a portion of the natural gas we need to fuel our natural gas-fired power plants in advance or entering into contracts that base the sale price of our electricity on the cost of the natural gas, effectively locking in a margin
- meeting our power sales commitments using power we generate ourselves or with power we buy at fixed prices, reducing our exposure to changes in commodity prices
- using derivative instruments to enter into offsetting or back-to-back positions to manage commodity price risk created by certain fixed and variable prices in arrangements for different pricing indices and delivery points.

Foreign exchange and interest rate risk
Certain of our businesses generate income in U.S. dollars, but since we report in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect our net income. As our U.S. dollar-denominated operations continue to grow, this exposure increases. The majority of this risk is offset by interest expense on U.S. dollar-denominated debt and by using foreign exchange derivatives.

We have floating interest rate debt which subjects us to interest rate cash flow risk. We manage this using a combination of interest rate swaps and options.

Average exchange rate – U.S. to Canadian dollars

2014	**1.10**
2013	1.03
2012	1.00

The impact of changes in the value of the U.S. dollar on our U.S. operations is significantly offset by other U.S. dollar-denominated items, as set out in the table below. Comparable EBIT is a non-GAAP measure. See page 24 for more information.

Significant U.S. dollar-denominated amounts

year ended December 31 (millions of US$)	**2014**	**2013**	**2012**
U.S. and International Natural Gas Pipelines comparable EBIT	**630**	542	660
U.S. Liquids Pipelines comparable EBIT	**570**	389	363
U.S. Power comparable EBIT	**269**	216	88
Interest on U.S. dollar-denominated long-term debt	**(854)**	(766)	(740)
Capitalized interest on U.S. dollar-denominated capital expenditures	**154**	219	124
U.S. non-controlling interests and other	**(234)**	(196)	(192)
	535	404	303

We hedge our net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, foreign exchange forward contracts and foreign exchange options.

Derivatives designated as a net investment hedge

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

	2014		2013	
at December 31 (millions of $)	**Fair value[1]**	**Notional or principal amount**	**Fair value[1]**	**Notional or principal amount**
U.S. dollar cross-currency interest rate swaps (maturing 2015 to 2019)[2]	**(431)**	**US 2,900**	(201)	US 3,800
U.S. dollar foreign exchange forward contracts (maturing 2015)	**(28)**	**US 1,400**	(11)	US 850
	(459)	**US 4,300**	(212)	US 4,650

1 Fair values equal carrying values.

2 Consolidated net income in 2014 included net realized gains of $21 million (2013 – gains of $29 million) related to the interest component of cross-currency swap settlements.

U.S. dollar-denominated debt designated as a net investment hedge

at December 31 (millions of $)	**2014**	**2013**
Carrying value	**17,000 (US 14,700)**	14,200 (US 13,400)
Fair value	**19,000 (US 16,400)**	16,000 (US 15,000)

The balance sheet classification of the fair value of derivatives used to hedge our U.S. dollar net investment in foreign operations is as follows:

at December 31 (millions of $)	**2014**	**2013**
Other current assets	**5**	5
Intangible and other assets	**1**	-
Accounts payable and other	**(155)**	(50)
Other long-term liabilities	**(310)**	(167)
	(459)	(212)

Counterparty credit risk

We have exposure to counterparty credit risk in the following areas:

- accounts receivable

- portfolio investments
- the fair value of derivative assets
- cash and notes receivable.

If a counterparty fails to meet its financial obligations to us according to the terms and conditions of the financial instrument, we could experience a financial loss. We manage our exposure to this potential loss using recognized credit management techniques, including:

- dealing with creditworthy counterparties – a significant amount of our credit exposure is with investment grade counterparties or, if not, is generally partially supported by financial assurances from investment grade parties
- setting limits on the amount we can transact with any one counterparty – we monitor and manage the concentration of risk exposure with any one counterparty, and reduce our exposure when we feel we need to and when it is allowed under the terms of our contracts
- using contract netting arrangements and obtaining financial assurances, such as guarantees and letters of credit or cash, when we believe it is necessary.

There is no guarantee that these techniques will protect us from material losses.

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. We had no significant credit losses in 2014 and no significant amounts past due or impaired at year end. We had a credit risk concentration of $258 million (US$222 million) at December 31, 2014 with one counterparty (2013 – $240 million (US$225 million)). This amount is secured by a guarantee from the counterparty's parent company and we anticipate collecting the full amount.

We have significant credit and performance exposure to financial institutions because they hold cash deposits and provide committed credit lines and letters of credit that help manage our exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

Liquidity risk
Liquidity risk is the risk that we will not be able to meet our financial obligations as they come due. We manage our liquidity by continuously forecasting our cash flow for a 12 month period and making sure we have adequate cash balances, cash flow from operations, committed and demand credit facilities and access to capital markets to meet our operating, financing and capital expenditure obligations under both normal and stressed economic conditions.

See page 90 Financial condition for more information about our liquidity.

Dealing with legal proceedings
Legal proceedings, arbitrations and actions are part of doing business. While we cannot predict the final outcomes of proceedings and actions with certainty, management does not expect any current proceeding or action to have a material impact on our consolidated financial position, results of operations or liquidity. We are not aware of any potential legal proceeding or action that would have a material impact on our consolidated financial position, results of operations or liquidity.

CONTROLS AND PROCEDURES

We meet Canadian and U.S. regulatory requirements for disclosure controls and procedures, internal control over financial reporting and related CEO and CFO certifications.

Disclosure controls and procedures

We carried out an evaluation under the supervision and with the participation of management, including our President and CEO and our CFO, of the effectiveness of our disclosure controls and procedures as at December 31, 2014 as required by the Canadian securities regulatory authorities and by the SEC. Based on this evaluation, our President and CEO and our CFO have concluded that the disclosure controls and procedures are effective in that they are designed to ensure that the information we are required to disclose in

reports we file with or send to securities regulatory authorities 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

We are responsible for establishing and maintaining adequate internal control over financial reporting, which is a process designed by, or under the supervision of, our President and CEO and our CFO, and effected by our board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Under the supervision and with the participation of management, including our President and CEO and our CFO, an evaluation of the effectiveness of the internal control over financial reporting was conducted as of December 31, 2014 based on the criteria described in "Internal Control – Integrated Framework" issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2014, the internal control over financial reporting was effective.

Our internal control over financial reporting as of December 31, 2014 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included herein.

Changes in internal control over financial reporting

Effective January 1, 2014, management successfully implemented an Enterprise Resource Planning (ERP) system, and made changes to certain related processes. As a result of the ERP system, certain processes supporting our internal control over financial reporting changed in 2014.

Other than this ERP system implementation there has been no change in our internal control over financial reporting that occurred during the year covered by this annual report that has materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Although this implementation changed certain specific activities within the accounting function, it did not significantly affect the overall controls and procedures we follow in establishing internal controls over financial reporting.

CEO AND CFO CERTIFICATIONS

Our President and CEO and our CFO have attested to the quality of the public disclosure in our fiscal 2014 reports filed with Canadian securities regulators and the SEC, and have filed certifications with them.

CRITICAL ACCOUNTING ESTIMATES

When we prepare financial statements that conform with GAAP, we are required to make certain estimates and assumptions that affect the timing and amount we record for our assets, liabilities, revenues and expenses because these items may be affected by future events. We base the estimates and assumptions on the most current information available, using our best judgment. We also regularly assess the assets and liabilities themselves.

The following accounting estimates require us to make the most significant assumptions when preparing our financial statements and changes in these assumptions could have a material impact on the financial statements from those estimates.

Rate-regulated accounting

Under GAAP, an asset qualifies to use rate-regulated accounting (RRA) when it meets three criteria:

- a regulator must establish or approve the rates for the regulated services or activities
- the regulated rates must be designed to recover the cost of providing the services or products
- it is reasonable to assume that rates set at levels to recover the cost can be charged to (and collected from) customers because of the demand for services or products and the level of direct and indirect competition.

We believe that the regulated natural gas pipelines and certain liquids pipelines projects we account for using RRA meet these criteria. The most significant impact of using these principles is the timing of when we recognize certain expenses and revenues, which is based on the economic impact of the regulators' decisions about our revenues and tolls, and may be different from what would otherwise be expected under GAAP. Regulatory assets represent costs that are expected to be recovered in customer rates in future periods. Regulatory liabilities are amounts that are expected to be refunded through customer rates in future periods.

Regulatory assets and liabilities

at December 31 (millions of $)	**2014**	**2013**
Regulatory assets		
Long-term assets	**1,297**	1,735
Short-term assets (included in other current assets)	**16**	42
Regulatory liabilities		
Long-term liabilities	**263**	229
Short-term liabilities (included in accounts payable and other)	**30**	7

Impairment of long-lived assets and goodwill

We review long-lived assets (such as plant, property and equipment) and intangible assets for impairment whenever events or changes in circumstances lead us to believe we might not be able to recover an asset's carrying value. If the total of the undiscounted future cash flows we estimate for an asset is less than its carrying value, we consider its fair value to be less than its carrying value and we calculate and record an impairment loss to recognize this.

Goodwill

We test goodwill for impairment annually or more frequently if events or changes in circumstances lead us to believe it might be impaired. We first assess qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired, and if we conclude that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, we use a two-step process to test for impairment:

1. First, we compare the fair value of the reporting unit to its book value, including its goodwill. If fair value is less than book value, we consider our goodwill to be impaired.

2. Next, we measure the amount of the impairment by calculating the implied fair value of the reporting unit's goodwill. We do this by deducting the fair value of the tangible and intangible net assets of the reporting unit from the fair value we calculated in the first step. If the goodwill's carrying value exceeds its implied fair value, we record an impairment charge.

We base these valuations on our projections of future cash flows, which involves making estimates and assumptions about:

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

If our assumptions change significantly, our requirement to record an impairment charge could also change. There is a risk that adverse changes in key assumptions could result in a future impairment of a portion of the goodwill balance relating to Great Lakes. These assumptions could be negatively impacted by factors including changes in customer demand at Great Lakes for pipeline capacity and services, weather, North American natural gas production and prices as well as natural gas storage market conditions. Our share of the goodwill related to Great Lakes, net of non-controlling interests, was US$243 million at December 31, 2014 (2013 – US$246 million).

Asset retirement obligations

When there is a legal obligation to set aside funds to cover future abandonment costs, and we can reasonably estimate them, we recognize the fair value of the asset retirement obligation (ARO) in our financial statements.

We cannot determine when we will retire many of our hydro-electric power plants, oil pipelines, natural gas pipelines and transportation facilities and regulated natural gas storage systems because we intend to operate them as long as there is supply and demand, and so we have not recorded obligations for them.

For those we do record, we use the following assumptions:

- when we expect to retire the asset
- the scope of abandonment and reclamation activities that are required
- inflation and discount rates.

The ARO is initially recorded when the obligation exists and is subsequently accreted through charges to operating expenses.

We continue to evaluate our future abandonment obligations and costs and monitor developments that could affect the amounts we record.

FINANCIAL INSTRUMENTS

All financial instruments, including both derivative and non-derivative instruments, are recorded on the balance sheet at fair value unless they were entered into and continue to be held for the purpose of receipt or delivery in accordance with our normal purchase and normal sales exemptions and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain accounting exemptions.

Non-derivative financial instruments

Fair value of non-derivative financial instruments

The fair value of our notes receivable is calculated by discounting future payments of interest and principal using forward interest rates. The fair value of long-term debt has been estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data providers. The fair value of available for sale assets has been calculated using quoted market prices where available. Credit risk has been taken into consideration when calculating the fair value of non-derivative financial instruments.

Certain non-derivative financial instruments including cash and cash equivalents, accounts receivable, intangibles and other assets, notes payable, accounts payable and other, accrued interest and other long-term liabilities have carrying amounts that equal their fair value due to the nature of the item or the short time to maturity.

Derivative instruments

We use derivative instruments to reduce volatility associated with fluctuations in commodity prices, interest rates and foreign exchange rates. We apply hedge accounting to derivative instruments that qualify and are designated for hedge accounting treatment. The effective portion of the change in the fair value of hedging derivatives for cash flow hedges and hedges of our net investment in foreign operations are recorded in other comprehensive income (OCI) in the period of change. Any ineffective portion is recognized in net income in the same financial category as the underlying transaction. The change in the fair value of derivative instruments that have been designated as fair value hedges are recorded in net income in interest income and other and interest expense.

The majority of derivative instruments that are not designated or do not qualify for hedge accounting treatment have been entered into as economic hedges to manage our exposure to market risk (held for trading). Changes in the fair value of held for trading derivative instruments are recorded in net income in the

period of change. This may expose us to increased variability in reported operating results since the fair value of the held for trading derivative instruments can fluctuate significantly from period to period.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipelines exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, can be recovered or refunded through the tolls charged by us. As a result, these gains and losses are deferred as regulatory assets or regulatory liabilities and are refunded to or collected from the ratepayers in subsequent years when the derivative settles.

Fair value of derivative instruments
The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses year-end market rates and applies a discounted cash flow valuation model. The fair value of power and natural gas derivatives 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. Credit risk has been taken into consideration when calculating the fair value of derivative instruments.

Balance sheet presentation of derivative instruments
The balance sheet classification of the fair value of derivative instruments is as follows:

at December 31 (millions of $)	**2014**	**2013**
Other current assets	**409**	395
Intangible and other assets	**93**	112
Accounts payable and other	**(749)**	(357)
Other long-term liabilities	**(411)**	(255)
	(658)	(105)

Anticipated timing of settlement – derivative instruments
The anticipated timing of settlement for derivative instruments assumes constant commodity prices, interest rates and foreign exchange rates. Settlements will vary based on the actual value of these factors at the date of settlement.

at December 31, 2014 (millions of $)	**Total fair value**	**2015**	**2016 and 2017**	**2018 and 2019**	**2020 and thereafter**
Derivative instruments held for trading					
Assets	436	363	62	7	4
Liabilities	(530)	(457)	(61)	(12)	-
Derivative instruments in hedging relationships					
Assets	66	47	17	2	-
Liabilities	(630)	(293)	(246)	(91)	-
	(658)	(340)	(228)	(94)	4

The effect of derivative instruments on the consolidated statement of income

The following summary does not include hedges of our net investment in foreign operations.

year ended December 31 (millions of $)	2014	2013
Derivative instruments held for trading [1]		
Amount of unrealized (losses)/gains in the year		
Power	**(5)**	19
Natural Gas	**(35)**	17
Foreign Exchange	**(20)**	(10)
Amount of realized (losses)/gains in the year		
Power	**(39)**	(49)
Natural Gas	**11**	(13)
Foreign Exchange	**(28)**	(9)
Derivative instruments in hedging relationships [2,3]		
Amount of realized gains/(losses) in the year		
Power	**130**	(19)
Natural Gas	**-**	(2)
Interest	**4**	5

1 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell power and natural gas are included net in energy revenues. Realized and unrealized gains and losses on interest rate and foreign exchange held for trading derivative instruments are included net in interest expense and interest income and other, respectively.

2 At December 31, 2014, all hedging relationships were designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $3 million (2013 – $5 million) and a notional amount of US$400 million (2013 – US$200 million). In 2014, net realized gains on fair value hedges were $7 million (2013 – $6 million) and were included in interest expense. In 2014 and 2013, we did not record any amounts in net income related to ineffectiveness for fair value hedges.

3 The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to energy revenues, interest expense and interest income and other, as appropriate, as the original hedged item settles. In 2014 and 2013, 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.

Derivatives in cash flow hedging relationships

The components of the consolidated statement of OCI related to derivatives in cash flow hedging relationships is as follows:

year ended December 31 (millions of $, pre-tax)	2014	2013
Change in fair value of derivative instruments recognized in OCI (effective portion)		
Power	**(126)**	117
Natural Gas	**(2)**	(1)
Foreign Exchange	**10**	5
	(118)	121
Reclassification of (losses)/gains on derivative instruments from AOCI to net income (effective portion) [1]		
Power	**(114)**	40
Natural Gas	**3**	4
Interest	**16**	16
	(95)	60
(Losses)/gains on derivative instruments recognized in earnings (ineffective portion)		
Power	**(13)**	8
	(13)	8

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI.

Credit risk related contingent features of derivative instruments

Derivatives often contain financial assurance provisions that may require us to provide collateral if a credit risk-related contingent event occurs (for example, if our credit rating is downgraded to non-investment grade). We may also need to provide collateral if the fair value of our derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at December 31, 2014, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $15 million (2013 – $16 million), with collateral provided in the normal course of business of nil (2013 – nil).

If the credit-risk-related contingent features in these agreements were triggered on December 31, 2014, we would have been required to provide additional collateral of $15 million (2013 – $16 million) to our counterparties. We have sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

ACCOUNTING CHANGES

Changes in accounting policies for 2014

Obligations resulting from joint and several liability arrangements

In February 2013, the FASB issued guidance for recognizing, measuring, and disclosing obligations resulting from joint and several liability arrangements when the total amount of the obligation is fixed at the reporting date. Debt arrangements, other contractual obligations, and settled litigation and judicial rulings are examples of these obligations. This new guidance was effective January 1, 2014 and there was no material impact on our consolidated financial statements as a result of applying this new standard.

Foreign currency matters – cumulative translation adjustment

In March 2013, the FASB issued amended guidance related to the release of the cumulative translation adjustment into net income when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets that is a business. This new guidance was applied prospectively from January 1, 2014.

Unrecognized tax benefit

In July 2013, the FASB issued amended guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. This new guidance was effective January 1, 2014 and there was no material impact on our consolidated financial statements as a result of applying this new standard.

Future accounting changes

Reporting discontinued operations

In April 2014, the FASB issued amended guidance on the reporting of discontinued operations. The criteria of what will qualify as a discontinued operation has changed and there are expanded disclosures required. This new guidance is effective from January 1, 2015 and will be applied prospectively. We do not expect the adoption of this new standard to have a material impact on our consolidated financial statements.

Revenue from contracts with customers

In May 2014, the FASB issued new guidance on Revenue from Contracts with Customers. This guidance supersedes the current revenue recognition requirements and most industry-specific guidance. This new guidance requires that an entity recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. This new guidance is effective from January 1, 2017 with two methods in which the amendment can be applied: (1) retrospectively to each prior reporting period presented, or (2) retrospectively with the cumulative effect recognized at the date of initial application. Early application is not permitted. We are currently evaluating the impact of the adoption of this ASU and have not yet determined the effect on our consolidated financial statements.

Reconciliation of Non-GAAP measures

year ended December 31 (millions of $, except per share amounts)	2014	2013	2012
EBITDA	**5,542**	4,958	4,204
Cancarb gain on sale	**(108)**	-	-
Niska contract termination	**43**	-	-
Gas Pacifico/INNERGY gain on sale	**(9)**	-	-
NEB 2013 Decision – 2012	**-**	(55)	-
Sundance A PPA arbitration decision – 2011	**-**	-	20
Non-comparable risk management activities	**53**	(44)	21
Comparable EBITDA	**5,521**	4,859	4,245
Comparable depreciation and amortization	**(1,611)**	(1,472)	(1,375)
Comparable EBIT	**3,910**	3,387	2,870
Other income statement items			
Comparable interest expense	**(1,198)**	(984)	(976)
Comparable interest income and other	**112**	42	86
Comparable income taxes	**(859)**	(662)	(477)
Net income attributable to non-controlling interests	**(153)**	(125)	(118)
Preferred share dividends	**(97)**	(74)	(55)
Comparable earnings	**1,715**	1,584	1,330
Specific items (net of tax)			
Cancarb gain on sale	**99**	-	-
Niska contract termination	**(32)**	-	-
Gas Pacifico/INNERGY gain on sale	**8**	-	-
NEB 2013 Decision – 2012	**-**	84	-
Part VI.I income tax adjustment	**-**	25	-
Sundance A PPA arbitration decision – 2011	**-**	-	(15)
Risk management activities[1]	**(47)**	19	(16)
Net income attributable to common shares	**1,743**	1,712	1,299
Comparable depreciation and amortization	**(1,611)**	(1,472)	(1,375)
Specific item:			
NEB 2013 Decision – 2012	**-**	(13)	-
Depreciation and amortization	**(1,611)**	(1,485)	(1,375)
Comparable interest expense	**(1,198)**	(984)	(976)
Specific items:			
NEB 2013 Decision – 2012	**-**	(1)	-
Interest expense	**(1,198)**	(985)	(976)
Comparable interest income and other	**112**	42	86
Specific items:			
NEB 2013 Decision – 2012	**-**	1	-
Risk management activities[1]	**(21)**	(9)	(1)
Interest income and other	**91**	34	85
Comparable income tax expense	**(859)**	(662)	(477)
Specific items:			
Cancarb gain on sale	**(9)**	-	-
Niska contract termination	**11**	-	-
Gas Pacifico/INNERGY gain on sale	**(1)**	-	-
NEB 2013 Decision – 2012	**-**	42	-
Part VI.I income tax adjustment	**-**	25	-
Sundance A PPA arbitration decision – 2011	**-**	-	5
Risk management activities[1]	**27**	(16)	6
Income tax expense	**(831)**	(611)	(466)

year ended December 31 ($ per share)	2014	2013	2012
Comparable earnings per common share	**$2.42**	$2.24	$1.89
Specific items (net of tax):			
Cancarb gain on sale	**0.14**	-	-
Niska contract termination	**(0.04)**	-	-
Gas Pacifico/INNERGY gain on sale	**0.01**	-	-
NEB 2013 Decision – 2012	**-**	0.12	-
Part VI.I Income tax adjustment	**-**	0.04	-
Sundance A PPA arbitration decision – 2011	**-**	-	(0.02)
Risk management activities[1]	**(0.07)**	0.02	(0.03)
Net income per common share	**$2.46**	$2.42	$1.84

1

year ended December 31 (millions of $)	2014	2013	2012
Canadian Power	**(11)**	(4)	4
U.S. Power	**(55)**	50	(1)
Natural Gas Storage	**13**	(2)	(24)
Foreign exchange	**(21)**	(9)	(1)
Income taxes attributable to risk management activities	**27**	(16)	6
Total (losses)/gains from risk management activities	**(47)**	19	(16)

Comparable EBITDA and comparable EBIT by business segment

year ended December 31, 2014 (millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	**3,250**	**1,059**	**1,360**	**(127)**	**5,542**
Cancarb gain on sale	**-**	**-**	**(108)**	**-**	**(108)**
Niska contract termination	**-**	**-**	**43**	**-**	**43**
Gas Pacifico/INNERGY gain on sale	**(9)**	**-**	**-**	**-**	**(9)**
Non-comparable risk management activities	**-**	**-**	**53**	**-**	**53**
Comparable EBITDA	**3,241**	**1,059**	**1,348**	**(127)**	**5,521**
Comparable depreciation and amortization	**(1,063)**	**(216)**	**(309)**	**(23)**	**(1,611)**
Comparable EBIT	**2,178**	**843**	**1,039**	**(150)**	**3,910**

year ended December 31, 2013 (millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	2,907	752	1,407	(108)	4,958
NEB 2013 Decision – 2012	(55)	-	-	-	(55)
Non-comparable risk management activities	-	-	(44)	-	(44)
Comparable EBITDA	2,852	752	1,363	(108)	4,859
Comparable depreciation and amortization	(1,013)	(149)	(294)	(16)	(1,472)
Comparable EBIT	1,839	603	1,069	(124)	3,387

year ended December 31, 2012 (millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	2,741	698	862	(97)	4,204
Sundance A PPA arbitration decision – 2011	-	-	20	-	20
Non-comparable risk management activities	-	-	21	-	21
Comparable EBITDA	2,741	698	903	(97)	4,245
Comparable depreciation and amortization	(933)	(145)	(283)	(14)	(1,375)
Comparable EBIT	1,808	553	620	(111)	2,870

QUARTERLY RESULTS

Selected quarterly consolidated financial data

(unaudited, millions of $, except per share amounts)

2014	Fourth	Third	Second	First
Revenues	**2,616**	**2,451**	**2,234**	**2,884**
Net income attributable to common shares	**458**	**457**	**416**	**412**
Comparable earnings	**511**	**450**	**332**	**422**
Comparable earnings per share	**$0.72**	**$0.63**	**$0.47**	**$0.60**
Share statistics				
Net income per share – basic and diluted	**$0.65**	**$0.64**	**$0.59**	**$0.58**
Dividends declared per common share	**$0.48**	**$0.48**	**$0.48**	**$0.48**

2013	Fourth	Third	Second	First
Revenues	2,332	2,204	2,009	2,252
Net income attributable to common shares	420	481	365	446
Comparable earnings	410	447	357	370
Comparable earnings per share	$0.58	$0.63	$0.51	$0.52
Share statistics				
Net income per share – basic and diluted	$0.59	$0.68	$0.52	$0.63
Dividends declared per common share	$0.46	$0.46	$0.46	$0.46

Factors affecting quarterly financial information by business segment

Quarter-over-quarter revenues and net income fluctuate for reasons that vary across our business segments.

In Natural Gas Pipelines, except for seasonal fluctuations in short-term throughput volumes on U.S. pipelines, quarter-over-quarter revenues and net income generally remain relatively stable during any fiscal year. Over the long term, however, they fluctuate because of:

- regulators' decisions
- negotiated settlements with shippers
- acquisitions and divestitures
- developments outside of the normal course of operations
- newly constructed assets being placed in service.

In Liquids Pipelines, annual revenues and net income are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income are affected by:

- developments outside of the normal course of operations
- newly constructed assets being placed in service
- regulatory decisions.

In Energy, quarter-over-quarter revenues and net income are affected by:

- weather
- customer demand
- market prices for natural gas and power
- capacity prices and payments
- planned and unplanned plant outages
- acquisitions and divestitures
- certain fair value adjustments
- developments outside of the normal course of operations
- newly constructed assets being placed in service.

Factors affecting financial information by quarter

We calculate comparable measures by adjusting certain GAAP and non-GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period.

Comparable earnings exclude the unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives provide effective economic hedges, but do not meet the criteria for hedge accounting. As a result, the changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them part of our underlying operations.

In fourth quarter 2014, comparable earnings excluded an $8 million after-tax gain on the sale of Gas Pacifico/INNERGY.

In second quarter 2014, comparable earnings excluded a $99 million after-tax gain on the sale of Cancarb Limited and a $32 million after-tax loss related to the termination of the Niska Gas Storage contract.

In second quarter 2013, comparable earnings excluded a $25 million favourable income tax adjustment due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax in June 2013.

In first quarter 2013, comparable earnings excluded $84 million of net income in 2013 related to 2012 from the NEB 2013 Decision.

FOURTH QUARTER 2014 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	2014	2013
Natural gas pipelines	**621**	498
Liquids pipelines	**230**	160
Energy	**219**	301
Corporate	**(43)**	(35)
Total segmented earnings	**1,027**	924
Interest expense	**(323)**	(240)
Interest income and other	**28**	1
Income before income taxes	**732**	685
Income tax expense	**(206)**	(208)
Net income	**526**	477
Net income attributable to non-controlling interests	**(43)**	(38)
Net income attributable to controlling interests	**483**	439
Preferred share dividends	**(25)**	(19)
Net income attributable to common shares	**458**	420
Net income per common share – basic and diluted	**$0.65**	$0.59

Net income attributable to common shares increased by $38 million for the three months ended December 31, 2014 compared to the same period in 2013. Net income included a gain on the sale of Gas Pacifico/INNERGY of $8 million after tax and unrealized gains and losses from changes in certain risk management activities. Excluding the impact of these items, comparable earnings in the three months ended December 31, 2014 increased over the same period in 2013 as discussed below in Comparable earnings.

The items discussed above were excluded from comparable earnings for the relevant periods. Certain unrealized fair value adjustments relating to certain risk management activities are also excluded from comparable earnings. The remainder of net income is equivalent to comparable earnings. A reconciliation of net income attributable to common shares to comparable earnings is shown in the following table.

Reconciliation of net income to comparable earnings

three months ended December 31 (millions of $, except per share amounts)	2014	2013
Net income attributable to common shares	**458**	420
Specific items (net of tax):		
Risk management activities[1]	**61**	(10)
Gas Pacifico/INNERGY gain on sale	**(8)**	-
Comparable earnings	**511**	410
Net income per common share	**$0.65**	$0.59
Specific items (net of tax):		
Risk management activities[1]	**0.08**	(0.01)
Gas Pacifico/INNERGY gain on sale	**(0.01)**	-
Comparable earnings per share	**$0.72**	$0.58

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three months ended December 31 (millions of $)	2014	2013
Canadian Power	**(11)**	(2)
U.S. Power	**(85)**	36
Natural Gas Storage	**9**	(5)
Foreign exchange	**(12)**	(9)
Income tax attributable to risk management activities	**38**	(10)
Total (losses)/gains from risk management activities	**(61)**	10

Comparable EBITDA and comparable EBIT by business segment

three months ended December 31, 2014 (millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Comparable EBITDA	**884**	**288**	**385**	**(36)**	**1,521**
Comparable depreciation and amortization	**(272)**	**(58)**	**(79)**	**(7)**	**(416)**
Comparable EBIT	**612**	**230**	**306**	**(43)**	**1,105**

three months ended December 31, 2013 (millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Comparable EBITDA	778	198	346	(31)	1,291
Comparable depreciation and amortization	(280)	(38)	(74)	(4)	(396)
Comparable EBIT	498	160	272	(35)	895

Comparable earnings
Comparable earnings in fourth quarter 2014 increased by $101 million or $0.14 per share compared to the same period in 2013. This was primarily the net effect of:

- incremental earnings from the Gulf Coast extension of the Keystone Pipeline System
- higher earnings from Canadian Mainline due to higher incentive earnings recorded in fourth quarter
- higher earnings from the Tamazunchale Extension which was placed in service in 2014
- higher earnings from Eastern Power due to higher contractual earnings at Bécancour and incremental earnings from solar facilities acquired in December 2013 and the second half of 2014
- higher earnings from U.S. Power due to higher generation, higher sales to wholesale, commercial and industrial customers and the impact of higher realized power and capacity prices
- higher interest expense from debt issuances and lower capitalized interest on projects placed in service.

The stronger U.S. dollar this quarter compared to the same period in 2013 positively impacted the translated results of our U.S. businesses, however, this impact was mostly offset by a corresponding increase in interest

expense on U.S. dollar-denominated debt as well as realized losses on foreign exchange hedges used to manage our net exposure through our hedging program.

Highlights by business segment

Natural Gas Pipelines
Natural Gas Pipelines segmented earnings increased by $123 million for the three months ended December 31, 2014 compared to the same period in 2013 and included a $9 million pre-tax gain related to the sale of Gas Pacifico/INNERGY in November 2014. This amount has been excluded in our calculation of comparable EBIT. The remainder of the Natural Gas Pipelines segmented earnings are equivalent to comparable EBIT and comparable EBITDA.

Comparable depreciation and amortization decreased by $8 million for the three months ended December 31, 2014 compared to the same period in 2013 as fourth quarter 2013 included the annual impact of the 2013-2014 NGTL Settlement approved by the NEB in November 2013. This settlement increased depreciation for 2013 and 2014. This decrease compared to 2013 was partially offset by depreciation on the Tamazunchale Extension for the period in 2014.

Canadian Pipelines
Net income and comparable earnings for the Canadian Mainline increased by $39 million for the three months ended December 31, 2014 compared to the same period in 2013 because of higher incentive earnings recorded in fourth quarter partially offset by higher carrying charges owed to shippers on the positive TSA balance. Results for both periods reflect an ROE of 11.50 per cent on deemed common equity of 40 per cent.

Net income for the NGTL System decreased by $13 million for the three months ended December 31, 2014 compared to the same period in 2013. The decrease was due to increased OM&A costs at risk under the terms of the 2013-2014 NGTL Settlement approved by the NEB in November 2013, partially offset by a higher average investment base in 2014. Additionally, results for the three months ended December 31, 2013 reflect the annual impact of the 2013-2014 NGTL Settlement, which included an ROE of 10.10 per cent on deemed common equity of 40 per cent and annual fixed amounts for certain OM&A costs.

U.S. and International Pipelines
Comparable EBITDA for the U.S. and international pipelines increased by US$35 million for the three months ended December 31, 2014 compared to the same period in 2013. This was due to:

- higher earnings from the Tamazunchale Extension which was placed in service in 2014
- higher transportation revenues on ANR and Great Lakes.

A stronger U.S. dollar had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. and International operations.

Liquids Pipelines
Liquids Pipelines segmented earnings increased by $70 million for the three months ended December 31, 2014 compared to the same period in 2013, and are equivalent to comparable EBIT, which along with comparable EBITDA are discussed below.

Comparable EBITDA for the Keystone Pipeline System increased by $94 million for the three months ended December 31, 2014 compared to the same period in 2013. This increase was primarily due to:

- incremental earnings from the Keystone Gulf Coast extension which was placed in service in January 2014
- a stronger U.S. dollar which had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

Comparable depreciation and amortization increased by $20 million for the three months ended December 31, 2014 compared to the same period in 2013 due to the Keystone Gulf Coast extension being placed in service.

Energy
Energy segmented earnings decreased by $82 million for the three months ended December 31, 2014 compared to the same period in 2013.

Energy segmented earnings for the three months ended December 31, 2014 and 2013 included unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain commodity price risks as follows:

	three months ended December 31	
Risk management activities (millions of $, pre-tax)	**2014**	**2013**
Canadian Power	**(11)**	(2)
U.S. Power	**(85)**	36
Natural Gas Storage	**9**	(5)
Total (losses)/gains from risk management activities	**(87)**	29

The quarterly variances in these unrealized gains and losses reflect the impact of changes in forward natural gas and power prices and the volume of our position for these particular derivatives over a certain period of time however; they do not accurately reflect the gains and losses that will be realized on settlement, or the offsetting impact of other derivative and non-derivative transactions that make up our business as a whole. As a result, we do not consider them part of our underlying operations and exclude them in our calculation of comparable EBIT.

Comparable EBITDA for Energy increased by $39 million for the three months ended December 31, 2014 compared to the same period in 2013 due to the net effect of:

- higher earnings from Eastern Power due to higher contractual earnings at Bécancour and incremental earnings from solar facilities acquired in the second half of 2014
- higher earnings from U.S. Power due to increased generation, higher sales to wholesale, commercial and industrial customers and the impact of higher realized power and capacity prices
- lower earnings from Natural Gas Storage due to weaker realized natural gas storage spreads and lower volumes of third party sales.

A stronger U.S. dollar had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

Comparable EBITDA for Eastern Power increased by $20 million for the three months ended December 31, 2014 compared to the same period in 2013 because of higher Bécancour contractual earnings and incremental earnings from solar facilities acquired in December 2013 and in the second half of 2014.

Equity income from Bruce A increased by $30 million for the three months ended December 31, 2014 compared to the same period in 2013 mainly due to higher generation levels and lower operating expenses. Fourth quarter 2014 results also include the impact of a deemed generation adjustment related to a prior quarter.

Equity income from Bruce B decreased $30 million for the three months ended December 31, 2014 compared to the same period in 2013 mainly due to lower volumes and higher operating costs resulting from higher planned outage days.

Comparable EBITDA for U.S. Power increased US$20 million for the three months ended December 31, 2014 compared to the same period in 2013. The increase was the net effect of:

- higher margins and higher sales volumes to wholesale, commercial and industrial customers
- higher realized capacity prices primarily in New York
- higher generation at our hydro and Ravenswood facility offset by lower realized power prices in New York and New England.

Comparable EBITDA for Natural Gas Storage and Other decreased $15 million for the three months ended December 31, 2014 compared to the same period in 2013 mainly due to lower realized natural gas storage spreads and lower volumes of third party sales.

Glossary

Units of measure

Bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
GWh	Gigawatt hours
KW-M	Kilowatt month
MMcf/d	Million cubic feet per day
MW	Megawatt(s)
MWh	Megawatt hours

General terms and terms related to our operations

bitumen	A thick, heavy oil that must be diluted to flow (also see: diluent). One of the components of the oil sands, along with sand, water and clay
Canadian Restructuring Proposal	Canadian Mainline business and services restructuring proposal and 2012 and 2013 Mainline final tolls application
cogeneration facilities	Facilities that produce both electricity and useful heat at the same time
diluent	A thinning agent made up of organic compounds. Used to dilute bitumen so it can be transported through pipelines
Eastern Triangle	Canadian Mainline region between North Bay, Toronto and Montréal
FIT	Feed-in tariff
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it
fracking	Hydraulic fracturing. A method of extracting natural gas from shale rock
GHG	Greenhouse gas
HSE	Health, safety and environment
investment base	Includes annual average assets in rate base as well as assets under construction
LNG	Liquefied natural gas
OM&A	Operating, maintenance and administration
PJM Interconnection area (PJM)	A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia
PPA	Power purchase arrangement
rate base	Our investment in assets used to provide transportation services on our natural gas pipelines
WCSB	Western Canada Sedimentary Basin

Accounting terms

AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive (loss)/income
ARO	Asset retirement obligations
ASU	Accounting Standards Update
DRP	Dividend reinvestment plan
EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes, depreciation and amortization
FASB	Financial Accounting Standards Board (U.S.)
OCI	Other comprehensive (loss)/income
RRA	Rate-regulated accounting
ROE	Rate of return on common equity
GAAP	U.S. generally accepted accounting principles

Government and regulatory bodies terms

CFE	Comisión Federal de Electricidad (Mexico)
CRE	Comisión Reguladora de Energia, or Energy Regulatory Commission (Mexico)
DOS	Department of State (U.S.)
EPA	Environmental Protection Agency (U.S.)
FERC	Federal Energy Regulatory Commission (U.S.)
IEA	International Energy Agency
IESO	Independent Electricity System Operator
ISO	Independent System Operator
LMCI	Land Matters Consultation Initiative (Canada)
NEB	National Energy Board (Canada)
OPA	Ontario Power Authority (Canada)
RGGI	Regional Greenhouse Gas Initiative (northeastern U.S.)
SEC	U.S. Securities and Exchange Commission

Management's report on Internal Control over Financial Reporting

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 United States generally accepted accounting principles (GAAP) and include amounts that are based on estimates and judgments. The MD&A is based on the Company's financial results. It compares the Company's financial and operating performance in 2014 to that in 2013, and highlights significant changes between 2013 and 2012. 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 control over financial reporting based on the framework in Internal Control – Integrated Framework 2013 issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded, based on its evaluation, that internal control over financial reporting was effective as of December 31, 2014, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

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

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

The shareholders have appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with GAAP. The reports of KPMG LLP outline the scope of its examinations and its opinions on the consolidated financial statements and the effectiveness of the Company's internal control over financial reporting.



Russell K. Girling
President and
Chief Executive Officer



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

February 12, 2015

Independent Auditors' Report of Registered Public Accounting Firm

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, 2014 and December 31, 2013, the consolidated statements of income, cash flows, comprehensive income, and equity for each of the years in the three-year period ended December 31, 2014, 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 U.S. 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 December 31, 2014 and December 31, 2013, and its consolidated results of operations and its consolidated cash flows for each of the years in the three-year period ended December 31, 2014 in accordance with U.S. generally accepted accounting principles.

OTHER MATTER

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), TransCanada Corporation's internal control over financial reporting as of December 31, 2014, based on the criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 12, 2015 expressed an unmodified (unqualified) opinion on the effectiveness of TransCanada Corporation's internal control over financial reporting.

KPMG LLP

Chartered Accountants
Calgary, Canada

February 12, 2015

Report of Independent Registered Public Accounting Firm

TO THE SHAREHOLDERS OF TRANSCANADA CORPORATION

We have audited TransCanada Corporation's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). TransCanada Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, TransCanada Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of TransCanada Corporation as of December 31, 2014 and December 31, 2013, and the related consolidated statements of income, comprehensive income, cash flows, and equity for each of the years in the three-year period ended December 31, 2014, and our report dated February 12, 2015 expressed an unmodified (unqualified) opinion on those consolidated financial statements.



Chartered Accountants
Calgary, Canada

February 12, 2015

Consolidated statement of income

year ended December 31 (millions of Canadian dollars, except per share amounts)	2014	2013	2012
Revenues			
Natural Gas Pipelines	**4,913**	4,497	4,264
Liquids Pipelines	**1,547**	1,124	1,039
Energy	**3,725**	3,176	2,704
	10,185	8,797	8,007
Income from Equity Investments (Note 8)	**522**	597	257
Operating and Other Expenses			
Plant operating costs and other	**2,973**	2,674	2,577
Commodity purchases resold	**1,836**	1,317	1,049
Property taxes	**473**	445	434
Depreciation and amortization	**1,611**	1,485	1,375
	6,893	5,921	5,435
Gain on Sale of Assets (Note 25)	**117**	–	–
Financial Charges/(Income)			
Interest expense (Note 15)	**1,198**	985	976
Interest income and other	**(91)**	(34)	(85)
	1,107	951	891
Income before Income Taxes	**2,824**	2,522	1,938
Income Tax Expense (Note 16)			
Current	**145**	43	181
Deferred	**686**	568	285
	831	611	466
Net Income	**1,993**	1,911	1,472
Net Income Attributable to Non-Controlling Interests (Note 18)	**153**	125	118
Net Income Attributable to Controlling Interests	**1,840**	1,786	1,354
Preferred Share Dividends (Note 20)	**97**	74	55
Net Income Attributable to Common Shares	**1,743**	1,712	1,299
Net Income per Common Share (Note 19)			
Basic and Diluted	**$2.46**	$2.42	$1.84
Dividends Declared per Common Share	**$1.92**	$1.84	$1.76
Weighted Average Number of Common Shares (millions)			
Basic	**708**	707	705
Diluted	**710**	708	706

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

Consolidated statement of comprehensive income

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Net Income	**1,993**	1,911	1,472
Other Comprehensive Income/(Loss), Net of Income Taxes			
Foreign currency translation gains and losses on net investments in foreign operations	**517**	383	(129)
Change in fair value of net investment hedges	**(276)**	(239)	44
Change in fair value of cash flow hedges	**(69)**	71	48
Reclassification to Net Income of gains and losses on cash flow hedges	**(55)**	41	138
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**(102)**	67	(73)
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**18**	23	22
Other Comprehensive Income/(Loss) on equity investments	**(204)**	234	(70)
Other Comprehensive Income/(Loss) (Note 21)	**(171)**	580	(20)
Comprehensive Income	**1,822**	2,491	1,452
Comprehensive Income Attributable to Non-Controlling Interests	**283**	191	97
Comprehensive Income Attributable to Controlling Interests	**1,539**	2,300	1,355
Preferred Share Dividends	**97**	74	55
Comprehensive Income Attributable to Common Shares	**1,442**	2,226	1,300

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

Consolidated statement of cash flows

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Cash Generated from Operations			
Net income	**1,993**	1,911	1,472
Depreciation and amortization	**1,611**	1,485	1,375
Deferred income taxes (Note 16)	**686**	568	285
Income from equity investments (Note 8)	**(522)**	(597)	(257)
Distributed earnings received from equity investments (Note 8)	**579**	605	376
Employee post-retirement benefits expense, net of funding (Note 22)	**37**	50	9
Gain on sale of assets (Note 25)	**(117)**	–	–
Equity AFUDC (Note 9)	**(95)**	(19)	(15)
Unrealized losses/(gains) on financial instruments	**74**	(35)	22
Other	**22**	32	17
(Increase)/decrease in operating working capital (Note 24)	**(189)**	(326)	287
Net cash provided by operations	**4,079**	3,674	3,571
Investing Activities			
Capital expenditures (Note 4)	**(3,550)**	(4,264)	(2,595)
Capital projects under development (Note 4)	**(807)**	(488)	(3)
Equity investments	**(256)**	(163)	(652)
Acquisitions, net of cash acquired (Note 25)	**(241)**	(216)	(214)
Proceeds from sale of assets, net of transaction costs (Note 25)	**196**	–	–
Deferred amounts and other	**514**	11	208
Net cash used in investing activities	**(4,144)**	(5,120)	(3,256)
Financing Activities			
Dividends on common shares (Note 19)	**(1,345)**	(1,285)	(1,226)
Dividends on preferred shares (Note 20)	**(94)**	(71)	(55)
Distributions paid to non-controlling interests	**(178)**	(166)	(135)
Notes payable issued/(repaid), net	**544**	(492)	449
Long-term debt issued, net of issue costs	**1,403**	4,253	1,491
Repayment of long-term debt	**(1,069)**	(1,286)	(980)
Common shares issued	**47**	72	53
Preferred shares issued, net of issue costs	**440**	585	–
Partnership units of subsidiary issued, net of issue costs	**79**	384	–
Preferred shares of subsidiary redeemed (Note 18)	**(200)**	(200)	–
Net cash (used in)/provided by financing activities	**(373)**	1,794	(403)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**–**	28	(15)
(Decrease)/Increase in Cash and Cash Equivalents	**(438)**	376	(103)
Cash and Cash Equivalents Beginning of year	**927**	551	654
Cash and Cash Equivalents End of year	**489**	927	551

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

Consolidated balance sheet

at December 31 (millions of Canadian dollars)	2014	2013
ASSETS		
Current Assets		
Cash and cash equivalents	**489**	927
Accounts receivable	**1,313**	1,122
Inventories	**292**	251
Other (Note 5)	**1,446**	847
	3,540	3,147
Plant, Property and Equipment (Note 7)	**41,774**	37,606
Equity Investments (Note 8)	**5,598**	5,759
Regulatory Assets (Note 9)	**1,297**	1,735
Goodwill (Note 10)	**4,034**	3,696
Intangible and Other Assets (Note 11)	**2,704**	1,955
	58,947	53,898
LIABILITIES		
Current Liabilities		
Notes payable (Note 12)	**2,467**	1,842
Accounts payable and other (Note 13)	**2,896**	2,155
Accrued interest	**424**	388
Current portion of long-term debt (Note 15)	**1,797**	973
	7,584	5,358
Regulatory Liabilities (Note 9)	**263**	229
Other Long-Term Liabilities (Note 14)	**1,052**	656
Deferred Income Tax Liabilities (Note 16)	**5,275**	4,564
Long-Term Debt (Note 15)	**22,960**	21,892
Junior Subordinated Notes (Note 17)	**1,160**	1,063
	38,294	33,762
EQUITY		
Common shares, no par value (Note 19) Issued and outstanding: December 31, 2014 – 709 million shares December 31, 2013 – 707 million shares	**12,202**	12,149
Preferred shares (Note 20)	**2,255**	1,813
Additional paid-in capital	**370**	401
Retained earnings	**5,478**	5,096
Accumulated other comprehensive loss (Note 21)	**(1,235)**	(934)
Controlling interests	**19,070**	18,525
Non-controlling interests (Note 18)	**1,583**	1,611
	20,653	20,136
	58,947	53,898

Commitments, Contingencies and Guarantees (Note 26)

Subsequent Events (Note 27)

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

Consolidated statement of equity

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Common Shares			
Balance at beginning of year	**12,149**	12,069	12,011
Shares issued on exercise of stock options (Note 19)	**53**	80	58
Balance at end of year	**12,202**	12,149	12,069
Preferred Shares			
Balance at beginning of year	**1,813**	1,224	1,224
Shares issued under public offering, net of issue costs	**442**	589	–
Balance at end of year	**2,255**	1,813	1,224
Additional Paid-In Capital			
Balance at beginning of year	**401**	379	380
Issuance of stock options, net of exercises	**3**	(2)	(1)
Dilution impact from TC PipeLines, LP units issued (Note 25)	**9**	29	–
Redemption of subsidiary's preferred shares	**(6)**	(5)	–
Impact of asset drop downs to TC Pipelines, LP (Note 25)	**(37)**	–	–
Balance at end of year	**370**	401	379
Retained Earnings			
Balance at beginning of year	**5,096**	4,687	4,628
Net income attributable to controlling interests	**1,840**	1,786	1,354
Common share dividends	**(1,360)**	(1,301)	(1,240)
Preferred share dividends	**(98)**	(76)	(55)
Balance at end of year	**5,478**	5,096	4,687
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(934)**	(1,448)	(1,449)
Other comprehensive (loss)/income	**(301)**	514	1
Balance at end of year	**(1,235)**	(934)	(1,448)
Equity Attributable to Controlling Interests	**19,070**	18,525	16,911
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,611**	1,425	1,465
Net income attributable to non-controlling interests			
TC PipeLines, LP	**136**	93	91
Preferred share dividends of TCPL	**2**	20	22
Portland	**15**	12	5
Other comprehensive income/(loss) attributable to non-controlling interests	**130**	66	(21)
Issuance of TC PipeLines, LP units			
Proceeds, net of issue costs	**79**	384	–
Decrease in TransCanada's ownership of TC PipeLines, LP	**(14)**	(47)	–
Distributions declared to non-controlling interests	**(182)**	(166)	(135)
Redemption of subsidiary's preferred shares	**(194)**	(195)	–
Foreign exchange and other	**–**	19	(2)
Balance at end of year	**1,583**	1,611	1,425
Total Equity	**20,653**	20,136	18,336

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

Notes to consolidated financial statements

1. DESCRIPTION OF TRANSCANADA'S BUSINESS

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

Natural Gas Pipelines
The Natural Gas Pipelines segment consists of the Company's investments in 68,000 km (42,000 miles) of regulated natural gas pipelines and 400 Bcf of regulated natural gas storage facilities. These assets are located in Canada, the United States and Mexico.

Liquids Pipelines
The Liquids Pipelines segment consists of 4,250 km (2,600 miles) of wholly owned and operated crude oil pipeline systems which connect Alberta and U.S. crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas.

Energy
The Energy segment primarily consists of the Company's investments in 19 electrical power generation plants and 2 non-regulated natural gas storage facilities. These include Canadian plants in Alberta, Ontario, Québec and New Brunswick and U.S. plants in New York, New England and Arizona.

2. ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with United States generally accepted accounting principles (GAAP). Amounts are stated in Canadian dollars unless otherwise indicated.

Basis of Presentation
The consolidated financial statements include the accounts of TransCanada and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control. To the extent there are interests owned by other parties, these interests are included in Non-Controlling Interests. TransCanada uses the equity method of accounting for joint ventures in which the Company is able to exercise joint control and for investments in which the Company is able to exercise significant influence. TransCanada records its proportionate share of undivided interests in certain assets. Certain prior year amounts have been reclassified to conform to current year presentation.

Use of Estimates and Judgments
In preparing these financial statements, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgment in making these estimates and assumptions. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to:

- carrying values and depreciation rates of plant, property and equipment (Note 7);
- carrying value of equity investments (Note 8);
- carrying value of regulatory assets and liabilities (Note 9);
- carrying value of goodwill (Note 10);
- amortization rates and carrying values of intangible assets (Note 11);

- carrying value of asset retirement obligations (Note 14);
- provisions for income taxes (Note 16);
- assumptions used to measure retirement and other postretirement obligations (Note 22);
- fair value of financial instruments (Note 23); and
- provision for commitments, contingencies and guarantees (Note 26).

Actual results could differ from those estimates.

Regulation

In Canada, regulated natural gas pipelines and liquids pipelines are subject to the authority of the National Energy Board (NEB) of Canada. In the U.S., natural gas pipelines, liquids pipelines and regulated natural gas storage assets are subject to the authority of the U.S. Federal Energy Regulatory Commission (FERC). In Mexico, natural gas pipelines are subject to the authority of the Energy Regulatory Commission of Mexico (CRE). The Company's Canadian, U.S. and Mexican natural gas transmission operations are regulated with respect to construction, operations and the determination of tolls. Rate-regulated accounting (RRA) standards may impact the timing of the recognition of certain revenues and expenses in TransCanada's rate-regulated businesses which may differ from that otherwise expected in non-rate-regulated businesses to appropriately reflect the economic impact of the regulators' decisions regarding revenues and tolls. TransCanada's businesses that apply RRA currently include Canadian, U.S. and Mexican natural gas pipelines, regulated U.S. natural gas storage and certain of our liquids pipelines projects. RRA is not applicable to the Keystone Pipeline System and, as a result, the regulators' decisions regarding operations and tolls on that system generally do not have an impact on timing of recognition of revenues and expenses.

Revenue Recognition

Natural Gas and Liquids Pipelines

Revenues from the Company's natural gas and liquids pipelines, with the exception of Canadian natural gas pipelines which are subject to RRA, are generated from contractual arrangements for committed capacity and from the transportation of natural gas or crude oil. Revenues earned from firm contracted capacity arrangements are recognized ratably over the contract period regardless of the amount of natural gas or crude oil that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when physical deliveries of natural gas or crude oil are made. The U.S. natural gas pipelines are subject to FERC regulations and, as a result, revenues collected may be subject to refund during a rate proceeding. Allowances for these potential refunds are recognized at the time of the regulatory decision.

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

Revenues from the Company's regulated natural gas storage services are recognized ratably over the contract period for firm committed capacity regardless of the amount of natural gas that is stored and when gas is injected or withdrawn for interruptible or volumetric-based services. The Company does not take ownership of the gas or oil that it transports or stores for others.

Energy

Power
Revenues from the Company's Energy business are primarily derived from the sale of electricity and from the sale of unutilized natural gas fuel, which are recorded at the time of delivery. Revenues also include capacity payments and ancillary services, as well as gains and losses resulting from the use of commodity derivative contracts. The accounting for derivative contracts is described in the Derivative Instruments and Hedging Activities section of this note.

Natural Gas Storage
Revenues earned from providing non-regulated natural gas storage services are recognized in accordance with the terms of the natural gas storage contracts, which is generally over the term of the contract. Revenues earned on the sale of proprietary natural gas are recorded in the month of delivery. Derivative contracts for the purchase or sale of natural gas are recorded at fair value with changes in fair value recorded in Revenues.

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

Inventories
Inventories primarily consist of materials and supplies, including spare parts and fuel, and natural gas inventory in storage, and are carried at the lower of weighted average cost or market.

Plant, Property and Equipment

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

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

Liquids Pipelines
Plant, property and equipment for liquids pipelines are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and pumping equipment are depreciated at annual rates ranging from two per cent to 2.5 per cent, and other plant and equipment are depreciated at various rates. The cost of these assets includes interest capitalized during construction for non-regulated liquids pipelines and AFUDC for regulated pipelines. When liquids pipelines retire plant, property and equipment from service, the original book cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in earnings.

Energy
Power generation and natural gas storage plant, equipment and structures are recorded at cost and, once the assets are ready for their intended use, depreciated by major component on a straight-line basis over their estimated service lives at average annual rates ranging from two per cent to 20 per cent. Other equipment is

depreciated at various rates. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. Interest is capitalized on facilities under construction. When these assets are retired from plant, property and equipment, the original book cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in earnings.

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

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

Acquisitions and Goodwill
The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Goodwill is not amortized and is tested for impairment on an annual basis or more frequently if events or changes in circumstances indicate that the asset might be impaired. The annual review for goodwill impairment is performed at the reporting unit level which is one level below the Company's operating segments. The Company initially assesses qualitative factors to determine whether events or changes in circumstances indicate that the goodwill might be impaired. If TransCanada concludes that it is not more likely than not that fair value of the reporting unit is greater than its carrying value, the first step of the two-step impairment test is performed by comparing the fair value of the reporting unit to its book value, which includes goodwill. If the fair value is less than book value, an impairment is indicated and a second step is performed to measure the amount of the impairment. In the second step, the implied fair value of goodwill is calculated by deducting the recognized amounts of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of goodwill exceeds the calculated implied fair value of goodwill, an impairment charge is recorded in an amount equal to the difference.

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

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

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

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

Recorded ARO relates to the non-regulated natural gas storage operations and certain power generation facilities. The scope and timing of asset retirements related to natural gas pipelines, liquids pipelines and hydroelectric power plants is indeterminable. As a result, the Company has not recorded an amount for ARO related to these assets, with the exception of certain abandoned facilities.

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

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

Stock Options and Other Compensation Programs
TransCanada's Stock Option Plan permits options for the purchase of common shares to be awarded to certain employees, including officers. Stock options granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated using a binomial model and is recognized on a straight-line basis over the vesting period, with an offset to Additional Paid-In Capital. Upon exercise of stock options, amounts originally recorded against Additional Paid-In Capital are reclassified to Common Shares.

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

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

The DB Plans' assets are measured at fair value at December 31 of each year. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service life of employees active at the date of amendment. The Company recognizes the overfunded or underfunded status of its DB Plans as an asset or liability, respectively, on its Balance Sheet and

recognizes changes in that funded status through Other Comprehensive Income (OCI) in the year in which the change occurs. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized out of Accumulated Other Comprehensive Loss (AOCI) over the average remaining service life of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

For certain regulated operations, post-retirement benefit amounts are recoverable through tolls as benefits are funded. The Company records any unrecognized gains or losses or changes in actuarial assumptions related to these post-retirement benefit plans as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the expected average remaining service life of active employees.

Foreign Currency Transactions and Translation

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the company or reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are recorded in income except for exchange gains and losses of the foreign currency debt related to Canadian regulated natural gas pipelines, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar reporting currency are reflected in OCI. Asset and liability accounts are translated at the period-end exchange rates while revenues, expenses, gains and losses are translated at the exchange rates in effect at the time of the transaction. The Company's U.S. dollar-denominated debt has been designated as a hedge of the net investment in foreign subsidiaries and, as a result, the unrealized foreign exchange gains and losses on the U.S. dollar denominated debt are also reflected in OCI.

Derivative Instruments and Hedging Activities

All derivative instruments are recorded on the balance sheet at fair value, unless they qualify for and are designated under a normal purchase and normal sales exemption, or are considered to meet other permitted exemptions.

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

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

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is initially recognized in OCI, while any ineffective portion is recognized in Net Income in the same financial statement category as the underlying transaction. When hedge accounting is discontinued, the

amounts recognized previously in AOCI are reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, during the periods when the variability in cash flows of the hedged item affects Net Income or as the original hedged item settles. Gains and losses on derivatives are reclassified immediately to Net Income from AOCI when the hedged item is sold or terminated early, or when it becomes probable that the anticipated transaction will not occur.

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

In some cases, derivatives do not meet the specific criteria for hedge accounting treatment. In these instances, the changes in fair value are recorded in Net Income in the period of change.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipelines exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, 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 and are refunded to or collected from the ratepayers, in subsequent years when the derivative settles.

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

Long-Term Debt Transaction Costs

The Company records Long-Term Debt transaction costs as other assets and amortizes these costs using the effective interest method for all costs except those related to the Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of regulatory tolling mechanisms.

Guarantees

Upon issuance, the Company records the fair value of certain guarantees entered into by the Company or partially owned entities for which contingent payments may be made. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees as appropriate in the circumstances. Guarantees are recorded as an increase to Equity Investments, Plant, Property and Equipment, or a charge to Net Income, and a corresponding liability is recorded in Other Long-Term Liabilities.

3. ACCOUNTING CHANGES

Changes in Accounting Policies for 2014

Obligations resulting from joint and several liability arrangements
In February 2013, the FASB issued guidance for recognizing, measuring, and disclosing obligations resulting from joint and several liability arrangements when the total amount of the obligation is fixed at the reporting date. Debt arrangements, other contractual obligations, and settled litigation and judicial rulings are examples of these obligations. This new guidance was effective January 1, 2014 and there was no material impact on the Company's consolidated financial statements as a result of applying this new standard.

Foreign currency matters – cumulative translation adjustment
In March 2013, the FASB issued amended guidance related to the release of the cumulative translation adjustment into net income when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets that is a business. This new guidance was applied prospectively from January 1, 2014 and there was no material impact on the Company's consolidated financial statements as a result of applying this new standard.

Unrecognized tax benefit
In July 2013, the FASB issued amended guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. This new guidance was effective January 1, 2014. There was no material impact on the Company's consolidated financial statements as a result of applying this new standard.

Future Accounting Changes

Reporting discontinued operations
In April 2014, the FASB issued amended guidance on the reporting of discontinued operations. The criteria of what will qualify as a discontinued operation has changed and there are expanded disclosures required. This new guidance is effective from January 1, 2015 and will be applied prospectively. The Company does not expect the adoption of this new standard to have a material impact on its consolidated financial statements.

Revenue from contracts with customers
In May 2014, the FASB issued new guidance on revenue from contracts with customers. This guidance supersedes the current revenue recognition requirements and most industry-specific guidance. This new guidance requires that an entity recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. This new guidance is effective from January 1, 2017 with two methods in which the amendment can be applied: (1) retrospectively to each prior reporting period presented, or (2) retrospectively with the cumulative effect recognized at the date of initial application. Early application is not permitted. The Company is currently evaluating the impact of the adoption of this ASU and has not yet determined the effect on its consolidated financial statements.

4. SEGMENTED INFORMATION

year ended December 31, 2014 (millions of Canadian dollars)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Revenues	4,913	1,547	3,725	–	10,185
Income from Equity Investments	163	–	359	–	522
Plant Operating Costs and Other	(1,501)	(426)	(919)	(127)	(2,973)
Commodity Purchases Resold	–	–	(1,836)	–	(1,836)
Property Taxes	(334)	(62)	(77)	–	(473)
Depreciation and Amortization	(1,063)	(216)	(309)	(23)	(1,611)
Gain on Sale of Assets	9	–	108	–	117
Segment earnings	2,187	843	1,051	(150)	3,931
Interest Expense					(1,198)
Interest Income and Other					91
Income before Income Taxes					2,824
Income Tax Expense					(831)
Net Income					1,993
Net Income Attributable to Non-Controlling Interests					(153)
Net Income Attributable to Controlling Interests					1,840
Preferred Share Dividends					(97)
Net Income Attributable to Common Shares					1,743
Capital Spending					
Capital Expenditures	1,768	1,530	206	46	3,550
Projects Under Development	368	439	–	–	807
	2,136	1,969	206	46	4,357
at December 31, 2014 (millions of Canadian dollars)					
Total Assets	27,103	16,116	14,197	1,531	58,947

year ended December 31, 2013 (millions of Canadian dollars)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Revenues	4,497	1,124	3,176	–	8,797
Income from Equity Investments	145	–	452	–	597
Plant Operating Costs and Other	(1,405)	(328)	(833)	(108)	(2,674)
Commodity Purchases Resold	–	–	(1,317)	–	(1,317)
Property Taxes	(329)	(44)	(72)	–	(445)
Depreciation and Amortization	(1,027)	(149)	(293)	(16)	(1,485)
Segment earnings	1,881	603	1,113	(124)	3,473
Interest Expense					(985)
Interest Income and Other					34
Income before Income Taxes					2,522
Income Tax Expense					(611)
Net Income					1,911
Net Income Attributable to Non-Controlling Interests					(125)
Net Income Attributable to Controlling Interests					1,786
Preferred Share Dividends					(74)
Net Income Attributable to Common Shares					1,712
Capital Spending					
Capital Expenditures	1,776	2,286	152	50	4,264
Projects Under Development	245	243	–	–	488
	2,021	2,529	152	50	4,752
at December 31, 2013 (millions of Canadian dollars)					
Total Assets	25,165	13,253	13,747	1,733	53,898

year ended December 31, 2012 (millions of Canadian dollars)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Revenues	4,264	1,039	2,704	–	8,007
Income from Equity Investments	157	–	100	–	257
Plant Operating Costs and Other	(1,365)	(296)	(819)	(97)	(2,577)
Commodity Purchases Resold	–	–	(1,049)	–	(1,049)
Property Taxes	(315)	(45)	(74)	–	(434)
Depreciation and Amortization	(933)	(145)	(283)	(14)	(1,375)
Segment earnings	1,808	553	579	(111)	2,829
Interest Expense					(976)
Interest Income and Other					85
Income before Income Taxes					1,938
Income Tax Expense					(466)
Net Income					1,472
Net Income Attributable to Non-Controlling Interests					(118)
Net Income Attributable to Controlling Interests					1,354
Preferred Share Dividends					(55)
Net Income Attributable to Common Shares					1,299
Capital Spending					
Capital Expenditures	1,389	1,145	24	37	2,595
Projects Under Development	–	3	–	–	3
	1,389	1,148	24	37	2,598
at December 31, 2012 (millions of Canadian dollars)					
Total Assets	23,210	10,485	13,157	1,481	48,333

Geographic Information

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Revenues			
Canada – domestic	**4,021**	4,659	3,527
Canada – export	**1,314**	997	1,121
United States	**4,653**	3,029	3,252
Mexico	**197**	112	107
	10,185	8,797	8,007

at December 31 (millions of Canadian dollars)	2014	2013
Plant, Property and Equipment		
Canada	**19,191**	18,462
United States	**20,098**	17,570
Mexico	**2,485**	1,574
	41,774	37,606

5. OTHER CURRENT ASSETS

at December 31 (millions of Canadian dollars)	2014	2013
Deferred income tax assets (Note 16)	**427**	119
Cash held as collateral	**423**	42
Fair value of derivative contracts (Note 23)	**409**	395
Other	**171**	164
Regulatory Assets (Note 9)	**16**	42
Assets held for sale (Note 6)	**–**	85
	1,446	847

6. ASSETS HELD FOR SALE

at December 31 (millions of Canadian dollars)	2013
Assets Held for Sale	
Cash and Cash Equivalents	1
Accounts Receivable	12
Inventories	11
Plant, Property and Equipment	61
Total Assets Held for Sale (included in Other Current Assets, Note 5)	85
Liabilities Related to Assets Held for Sale	
Accounts Payable and Other	4
Other Long-Term Liabilities	1
Total Liabilities Related to Assets Held for Sale (included in Accounts Payable and Other, Note 13)	5

The Company classifies assets as held for sale when management approves and commits to a formal plan to actively market an asset for sale and expects the sale to close within the next twelve months. Upon classifying an asset as held for sale, an asset is recorded at the lower of its carrying amount or its estimated fair value, reduced for selling costs, and depreciation expense is no longer recorded for that asset.

At December 31, 2013, the Company classified Cancarb Limited and its related power generation facility as assets held for sale in the Energy segment. The assets were recorded at their carrying amount at December 31, 2013.

On April 15, 2014, the Company sold these assets for aggregate gross proceeds of $190 million and recognized a gain of $108 million ($99 million after tax).

7. PLANT, PROPERTY AND EQUIPMENT

at December 31 (millions of Canadian dollars)	2014 Cost	2014 Accumulated Depreciation	2014 Net Book Value	2013 Cost	2013 Accumulated Depreciation	2013 Net Book Value
Natural Gas Pipelines						
Canadian Mainline						
Pipeline	**9,045**	**5,712**	**3,333**	8,970	5,457	3,513
Compression	**3,423**	**2,100**	**1,323**	3,392	1,961	1,431
Metering and other	**458**	**180**	**278**	409	174	235
	12,926	**7,992**	**4,934**	12,771	7,592	5,179
Under construction	**135**	**–**	**135**	85	–	85
	13,061	**7,992**	**5,069**	12,856	7,592	5,264
NGTL System						
Pipeline	**8,185**	**3,619**	**4,566**	7,813	3,410	4,403
Compression	**2,055**	**1,318**	**737**	2,038	1,253	785
Metering and other	**1,032**	**446**	**586**	947	418	529
	11,272	**5,383**	**5,889**	10,798	5,081	5,717
Under construction	**413**	**–**	**413**	290	–	290
	11,685	**5,383**	**6,302**	11,088	5,081	6,007
ANR						
Pipeline	**1,087**	**85**	**1,002**	922	59	863
Compression	**741**	**102**	**639**	635	81	554
Metering and other	**617**	**110**	**507**	535	91	444
	2,445	**297**	**2,148**	2,092	231	1,861
Under construction	**115**	**–**	**115**	67	–	67
	2,560	**297**	**2,263**	2,159	231	1,928
Other Natural Gas Pipelines						
GTN	**1,842**	**588**	**1,254**	1,685	488	1,197
Great Lakes	**1,807**	**939**	**868**	1,650	833	817
Foothills	**1,671**	**1,180**	**491**	1,649	1,120	529
Mexico	**1,518**	**130**	**1,388**	641	90	551
Other[1]	**1,800**	**363**	**1,437**	1,652	288	1,364
	8,638	**3,200**	**5,438**	7,277	2,819	4,458
Under construction	**1,132**	**–**	**1,132**	1,047	–	1,047
	9,770	**3,200**	**6,570**	8,324	2,819	5,505
	37,076	**16,872**	**20,204**	34,427	15,723	18,704
Liquids Pipelines						
Keystone						
Pipeline	**7,931**	**463**	**7,468**	5,079	286	4,793
Pumping equipment	**964**	**80**	**884**	1,118	82	1,036
Tanks and other	**2,282**	**144**	**2,138**	962	71	891
	11,177	**687**	**10,490**	7,159	439	6,720
Under construction[2]	**4,438**	**–**	**4,438**	6,020	–	6,020
	15,615	**687**	**14,928**	13,179	439	12,740
Energy						
Natural Gas – Ravenswood	**2,140**	**476**	**1,664**	1,966	377	1,589
Natural Gas – Other[3,4]	**3,214**	**971**	**2,243**	3,061	846	2,215
Hydro	**736**	**156**	**580**	673	126	547
Wind	**970**	**190**	**780**	946	155	791
Natural Gas Storage	**653**	**99**	**554**	677	92	585
Solar[5]	**488**	**13**	**475**	226	2	224
Other	**64**	**19**	**45**	57	30	27
	8,265	**1,924**	**6,341**	7,606	1,628	5,978
Under construction	**149**	**–**	**149**	54	–	54
	8,414	**1,924**	**6,490**	7,660	1,628	6,032
Corporate	**232**	**80**	**152**	191	61	130
	61,337	**19,563**	**41,774**	55,457	17,851	37,606

[1] Includes Bison, Portland, North Baja, Tuscarora and Ventures LP.

[2] Includes $3.2 billion for Keystone XL at December 31, 2014 (2013 – $2.6 billion). Keystone XL remains subject to regulatory approvals.

[3] Includes facilities with long-term PPAs that are accounted for as operating leases. The cost and accumulated depreciation of these facilities were $695 million and $103 million, respectively, at December 31, 2014 (2013 – $640 million and $78 million, respectively). Revenues of $81 million were recognized in 2014 (2013 – $78 million; 2012 – $73 million) through the sale of electricity under the related PPAs.

[4] Includes Halton Hills, Coolidge, Bécancour, Ocean State Power, Mackay River and other natural gas-fired facilities.

[5] Includes the acquisitions of four solar power facilities in each of 2014 and 2013.

8. EQUITY INVESTMENTS

		Income/(Loss) from Equity Investments			Equity Investments	
	Ownership Interest at	year ended December 31			at December 31	
(millions of Canadian dollars)	December 31, 2014	2014	2013	2012	2014	2013
Natural Gas Pipelines						
Northern Border[1,2]		**76**	66	72	**587**	557
Iroquois	44.5%	**43**	41	41	**210**	188
TQM	50.0%	**12**	13	16	**73**	76
Other	Various	**32**	25	28	**68**	62
Energy						
Bruce A[3]	48.9%	**209**	202	(149)	**3,944**	3,988
Bruce B[3]	31.6%	**105**	108	163	**51**	377
ASTC Power Partnership	50.0%	**8**	110	40	**29**	41
Portlands Energy	50.0%	**36**	31	28	**335**	343
Other[4]	Various	**1**	1	18	**61**	57
Liquids Pipelines						
Grand Rapids	50.0%	**–**	–	–	**240**	70
		522	597	257	**5,598**	5,759

[1] The results reflect a 50 per cent interest in Northern Border as a result of the Company fully consolidating TC PipeLines, LP. At December 31, 2014, TransCanada had an ownership interest in TC PipeLines, LP of 28.3 per cent (2013 – 28.9 and 2012 – 33.3 per cent) and its effective ownership of Northern Border, net of non-controlling interests, was 14.2 per cent (2013 – 14.5 and 2012 – 16.7 per cent).

[2] At December 31, 2014, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Border Pipeline Company is US$117 million (2013 – US$118 million) due to the fair value assessment of assets at the time of acquisition.

[3] At December 31, 2014, the difference between the carrying value of the investment and the underlying equity in the net assets of Bruce Power is $776 million (2013 – $820 million) due to the fair value assessment of assets at the time of acquisition.

[4] In December 2012, TransCanada acquired the remaining 40 per cent interest in CrossAlta to bring the Company's ownership interest to 100 per cent. The results reflect the Company's 60 per cent share of equity income up to that date.

Distributions received from equity investments for the year ended December 31, 2014 were $726 million (2013 – $725 million; 2012 – $436 million) of which $147 million (2013 – $120 million; 2012 – $60 million) were returns of capital and are included in Deferred Amounts and Other in the Consolidated Statement of Cash Flows. The undistributed earnings from equity investments as at December 31, 2014 were $551 million (2013 – $754 million; 2012 – $883 million).

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Income			
Revenues	**4,814**	4,989	3,860
Operating and Other Expenses	**(3,489)**	(3,536)	(3,090)
Net Income	**1,264**	1,390	717
Net Income attributable to TransCanada	**522**	597	257

at December 31 (millions of Canadian dollars)	2014	2013
Balance Sheet		
Current assets	**1,412**	1,500
Non current assets	**12,260**	12,158
Current liabilities	**(1,067)**	(1,117)
Non current liabilities	**(3,255)**	(2,507)

9. RATE-REGULATED BUSINESSES

TransCanada's businesses that apply RRA currently include Canadian, U.S. and Mexican natural gas pipelines, regulated U.S. natural gas storage and certain Canadian liquids pipelines currently under development. Regulatory assets and liabilities represent future revenues that are expected to be recovered from or refunded to customers based on decisions and approvals by the applicable regulatory authorities.

Canadian Regulated Operations

The Canadian Mainline, NGTL System, Foothills and TQM pipelines are regulated by the NEB under the *National Energy Board Act* (Canada). The NEB regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's Canadian regulated natural gas transmission systems.

TransCanada's Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and return on capital as approved by the NEB. Rates charged for these services are typically set through a process that involves filing an application with the regulator wherein forecasted operating costs, including a return of and on capital, determine the revenue requirement for the upcoming year or multiple years. To the extent that actual costs and revenues are more or less than the forecasted costs and revenues, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Differences between actual and forecasted costs that the regulator does not allow to be deferred are included in the determination of net income in the year they occur.

Canadian Mainline

On November 28, 2014, the NEB released its decision on TransCanada's 2015-2030 Tolls Application (the NEB 2014 Decision). The NEB 2014 Decision acknowledged that an off-ramp had been reached on the NEB 2013 Decision (discussed below) and approved fixed tolls for 2015 to 2020 as well as certain parameters for a toll setting methodology to 2030. Features of the settlement reached with shippers as approved in the NEB 2014 Decision include an ROE of 10.1 per cent on a deemed common equity of 40 per cent, an incentive mechanism that has both upside and downside risk and a $20 million after-tax annual TransCanada contribution to reduce the revenue requirement. Toll stabilization is achieved through the continued use of deferral accounts, namely the Long Term Adjustment Account (LTAA) and the Bridging Amortization Account, to capture the surplus or the shortfall between the Company's revenues and cost of service for each year over

the six-year fixed toll term of the NEB 2014 Decision. TransCanada is required to file a compliance filing with the NEB in first quarter 2015 and a toll review for the 2018 to 2020 period prior to December 31, 2017.

In March 2013, TransCanada received a decision from the NEB which set tolls for 2013 through 2017 at competitive levels, fixing tolls for some services and providing unlimited pricing discretion for others (the NEB 2013 Decision). The decision established an ROE of 11.5 per cent on a deemed common equity of 40 per cent and included mechanisms to achieve the fixed tolls through the use of a LTAA as well as the establishment of a Tolls Stabilization Account (TSA) to capture the surplus or the shortfall between our revenues and our cost of service for each year over the five-year term of the decision. In addition, the decision provided an opportunity to generate incentive earnings by increasing revenues and reducing costs. The NEB also identified certain circumstances that would require a new tolls application prior to the end of the five-year term. One of those circumstances occurred in 2013 when the TSA balance became positive. In December 2013, TransCanada filed the 2015-2030 Tolls Application with the NEB that addressed tolls moving forward including tolls for 2014.

The Canadian Mainline's 2012 results reflect an ROE of 8.08 per cent on a deemed common equity of 40 per cent and excluded incentive earnings.

NGTL System
In November 2013, the NEB approved the NGTL System's 2013-2014 Revenue Requirement Settlement Application. This settlement is structured similar to the previous multi-year settlement with fixed annual operating, maintenance and administration (OM&A) costs and a 10.1 per cent ROE on a deemed common equity of 40 per cent. Any variance between fixed OM&A costs in the settlement and actual costs accrue to TransCanada. The Settlement also establishes an increase in the composite depreciation rates to 3.05 per cent in 2013 and 3.12 per cent in 2014.

The NGTL System's 2012 results reflected a 9.70 per cent ROE on a deemed common equity of 40 per cent and fixed certain annual OM&A costs. Any variances between actual costs and those agreed to in the settlement then in effect accrued to TransCanada. All other costs were treated on a flow-through basis.

Energy East
Energy East is currently in the development stage, awaiting regulatory approval from the NEB. Tolls will be designed to provide for cost recovery including return of and on capital as approved by the NEB.

Other Canadian Pipelines
The Foothills operating model for 2012 through 2014 provides for recovery of all revenue requirement components on a flow-through basis. TQM operates under a model consisting of fixed and flow-through revenue requirement components for 2012 through 2016. Any variances between actual costs and those included in the fixed component accrue to TQM.

U.S. Regulated Operations
TransCanada's U.S. natural gas pipelines are "natural gas companies" operating under the provisions of the *Natural Gas Act of 1938,* the *Natural Gas Policy Act of 1978* (NGA) and the *Energy Policy Act of 2005*, and are subject to the jurisdiction of the FERC. The NGA grants the FERC authority over the construction and operation of pipelines and related facilities. The FERC also has authority to regulate rates for natural gas transportation in interstate commerce. The Company's significant regulated U.S. natural gas pipelines are described below.

ANR
ANR's natural gas transportation and storage services are provided 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 for all periods presented, 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 rates were established pursuant to a settlement approved by the FERC in August 2012. ANR Storage Company is required to file a NGA Section 4 general rate case no later than July 1, 2016.

TC Offshore LLC, another ANR-related regulated entity, began operating under FERC approved tariff rates on November 1, 2012. TC Offshore LLC is required to file a cost and revenue study to justify its existing approved cost-based rates after its first three years of operation.

Great Lakes
Great Lakes is regulated by the FERC and operates in accordance with a FERC-approved tariff that establishes maximum and minimum rates for its various services and permits Great Lakes to discount or negotiate rates on a non-discriminatory basis. Great Lakes operated under a July 2010 FERC approved rate settlement through October 2013. Effective November 1, 2013, Great Lakes operates under rates established pursuant to a settlement approved by the FERC in November 2013. The settlement provides for a moratorium between November 2013 and March 2015 during which Great Lakes and the settling parties are prohibited from taking certain actions under the NGA, including filing to adjust rates. Great Lakes is required to file for new rates to be effective no later than January 2018.

Other U.S. Pipelines
GTN and Bison are regulated by the FERC and operate in accordance with FERC-approved tariffs that establish maximum and minimum rates for various services. Both pipelines are permitted to discount or negotiate these rates on a non-discriminatory basis. GTN's rates were established pursuant to a settlement approved by the FERC in January 2012. GTN is required to file for new rates to be effective no later than January 2016.

Bison's rates were established pursuant to its initial certificate to construct and operate the pipeline that initiated service in January 2011. Bison filed a cost and revenue study as required by FERC to justify its existing approved cost-based rates after its first three years of operations. This study was filed by Bison on April 10, 2014 and accepted by FERC on May 20, 2014. At this time Bison 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.

Mexico Regulated Operations
TransCanada's Mexican operations are regulated by the CRE and operate in accordance with CRE-approved tariffs. In 2014, TransCanada began using RRA for all natural gas pipelines in Mexico. The rates were established based on CRE approved negotiated contracts.

Regulatory Assets and Liabilities

at December 31 (millions of Canadian dollars)	2014	2013	Remaining Recovery/ Settlement Period (years)
Regulatory Assets			
Deferred income taxes[1]	**1,001**	1,149	n/a
Operating and debt-service regulatory assets[2]	**4**	16	1
Pensions and other post retirement benefits[3]	**236**	190	n/a
Long Term Adjustment Account[4]	**–**	354	31
Other[5]	**72**	68	n/a
	1,313	1,777	
Less: Current portion included in Other Current Assets (Note 5)	**16**	42	
	1,297	1,735	
Regulatory Liabilities			
Foreign exchange on long-term debt[6]	**42**	84	1-15
Operating and debt-service regulatory liabilities[2]	**21**	5	1
ANR-related post-employment and retirement benefits other than pension[7]	**117**	104	n/a
Long Term Adjustment Account[4]	**64**	–	44
Other[5]	**49**	43	n/a
	293	236	
Less: Current portion included in Accounts Payable and Other (Note 13)	**30**	7	
	263	229	

1 These regulatory assets are underpinned by non-cash transactions or are recovered without an allowance for return as approved by the regulator. Accordingly, these regulatory assets are not included in rate base and do not yield a return on investment during the recovery period.

2 Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determining tolls for the following calendar year. Pre-tax operating results in 2014 would have been $28 million higher (2013 – $76 million higher; 2012 – $50 million lower) had these amounts not been recorded as regulatory assets and liabilities.

3 These balances represent the regulatory offset to pension plan and other post retirement obligations to the extent the amounts are expected to be collected from customers in future rates. The balances are excluded from the rate base and do not earn a return on investment. Pre-tax operating results in 2014 would have been $46 million lower (2013 – $171 million higher; 2012 – $61 million lower) had these amounts not been recorded as regulatory assets and liabilities.

4 The LTAA was established in compliance with the NEB 2013 Decision which is comprised of amounts that were deferred and recoverable in future years. The TSA, also established in the NEB 2013 Decision, includes the variances between revenue and costs. A positive balance in the TSA was realized in 2013 and 2014 and, as specified in the NEB 2013 Decision and the NEB 2014 Decision, the TSA, net of incentive earnings, was combined with the LTAA on December 31, 2013 and 2014.

5 Pre-tax operating results in 2014 would have been $2 million higher (2013 – $2 million higher; 2012 – $66 million higher) had these amounts not been recorded as regulatory assets and liabilities.

6 Foreign exchange on long-term debt of the NGTL System and Foothills represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate at the time of issue. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls. In the absence of RRA, GAAP would have required the inclusion of these unrealized gains or losses in Net Income.

7 Under the terms of the settlement of ANR's last rate settlement, ANR will be required to make refunds to its customers, pursuant to a refund plan to be approved by FERC in a future rate proceeding, of those amounts in the postretirement benefit trust fund that have not been used to pay benefits to its employees. This regulatory liability represents the difference between the amount collected in rates and the amount of postretirement benefits expense. ANR can but is not required to file for new rates. Therefore, the settlement/recovery period is not determinable. Pre-tax operating results in 2014 would have been $13 million higher (2013 – $16 million higher; 2012 – $8 million higher) had these amounts not been recorded as regulatory assets and liabilities.

Allowance for Funds Used During Construction

The total amount of AFUDC included in the Consolidated Statement of Income was $95 million in 2014, $19 million in 2013 and $15 million in 2012.

10. GOODWILL

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

(millions of Canadian dollars)	Natural Gas Pipelines	Energy	Total
Balance at January 1, 2013	2,635	823	3,458
Foreign exchange rate changes	181	57	238
Balance at December 31, 2013	2,816	880	3,696
Foreign exchange rate changes	**258**	**80**	**338**
Balance at December 31, 2014	**3,074**	**960**	**4,034**

11. INTANGIBLE AND OTHER ASSETS

at December 31 (millions of Canadian dollars)	**2014**	**2013**
Capital projects under development	**1,286**	571
PPAs	**272**	324
Deferred income tax assets and charges (Note 16)	**180**	225
Loans and advances[1]	**167**	183
Fair value of derivative contracts (Note 23)	**93**	112
Employee post-retirement benefits (Note 22)	**14**	16
Other	**692**	524
	2,704	1,955

1 TransCanada held a note receivable from the seller of Ravenswood of $213 million (US$184 million) and $226 million (US$212 million) as at December 31, 2014 and at December 31, 2013, respectively which bears interest at 6.75 per cent and matures in 2040. The current portion included in Other Current Assets was $46 million (US$40 million) at December 31, 2014, and $43 million (US$40 million) at December 31, 2013.

The following amounts related to PPAs are included in Intangible and Other Assets:

at December 31 (millions of Canadian dollars)	2014 Cost	2014 Accumulated Amortization	2014 Net Book Value	2013 Cost	2013 Accumulated Amortization	2013 Net Book Value
Sheerness	**585**	**351**	**234**	585	312	273
Sundance A	**225**	**187**	**38**	225	174	51
	810	**538**	**272**	810	486	324

Amortization expense for these PPAs was $52 million for the year ended December 31, 2014 (2013 and 2012 – $52 million). The expected annual amortization expense for 2015 to 2017 is $52 million, and $39 million for 2018 and 2019.

12. NOTES PAYABLE

(millions of Canadian dollars)	2014 Outstanding December 31	2014 Weighted Average Interest Rate per Annum at December 31	2013 Outstanding December 31	2013 Weighted Average Interest Rate per Annum at December 31
Canadian dollars	**1,540**	**1.2%**	751	1.2%
U.S. dollars (2014 – US$800; 2013 – US$1,025)	**927**	**0.7%**	1,091	0.3%
	2,467		1,842	

Notes Payable consists of commercial paper issued by TransCanada PipeLines Limited (TCPL), TransCanada PipeLine USA Ltd. (TCPL USA), TransCanada American Investments Ltd. (TAIL), and TransCanada Keystone Pipeline, LP (TC Keystone) and drawings on credit facilities. The TC Keystone commercial paper program and facility were terminated in November 2013. The TAIL commercial paper program was initiated in November 2013, replacing the TCPL USA program which was terminated in April 2014.

Notes Payable also includes a US$170 million short-term loan, which was issued on October 1, 2014, by TC Pipelines LP.

At December 31, 2014, total committed revolving and demand credit facilities of $6.7 billion (2013 – $6.2 billion) were available. When drawn, interest on these lines of credit is charged at prime rates of

Canadian and U.S. banks, and at other negotiated financial bases. These unsecured credit facilities included the following:

at December 31, 2014					year ended December 31		
					2014	2013	2012
Amount	**Unused Capacity**	**Borrower**	**For**	**Matures**	**Cost to maintain**		
					(millions of Canadian dollars)		
$3 billion	$3 billion	TCPL	Committed, syndicated, revolving, extendible TCPL credit facility	December 2019	6	4	4
US$1 billion	US$1 billion	TCPL USA	Committed, syndicated, revolving, extendible TCPL USA credit facility, guaranteed by TCPL	November 2015	2	1	1
US$1 billion	US$1 billion	TAIL	Committed, syndicated, revolving, extendible TAIL credit facility, guaranteed by TCPL	November 2015	1	–	–
$1.4 billion	$0.6 billion	TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity	Demand	–	–	–

13. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian dollars)	2014	2013
Trade payables	**1,624**	866
Fair value of derivative contracts (Note 23)	**749**	357
Dividends payable	**359**	338
Deferred Income Tax Liabilities (Note 16)	**4**	26
Regulatory Liabilities (Note 9)	**30**	7
Liabilities related to assets held for sale (Note 6)	**–**	5
Other	**130**	556
	2,896	2,155

14. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian dollars)	2014	2013
Employee post-retirement benefit (Note 22)	**444**	244
Fair value of derivative contracts (Note 23)	**411**	255
Asset retirement obligations	**98**	83
Guarantees (Note 26)	**15**	18
Other	**84**	56
	1,052	656

15. LONG-TERM DEBT

Outstanding loan amounts (millions of Canadian dollars)	Maturity Dates	2014 Outstanding December 31	2014 Interest Rate[1]	2013 Outstanding December 31	2013 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian dollars	2015 to 2020	**749**	**10.9%**	874	10.9%
U.S. dollars (2014 and 2013 US$400)	2021	**464**	**9.9%**	425	9.9%
Medium-Term Notes					
Canadian dollars	2016 to 2041	**4,048**	**5.7%**	4,799	5.7%
Senior Unsecured Notes					
U.S. dollars (2014 – US$13,526; 2013 – US$12,276)	2015 to 2043	**15,655**	**5.0%**	13,027	5.0%
		20,916		19,125	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian dollars[2]	2016 to 2024	**325**	**11.5%**	378	11.5%
U.S. dollars (2014 and 2013 – US$200)	2023	**232**	**7.9%**	213	7.9%
Medium-Term Notes					
Canadian dollars	2025 to 2030	**504**	**7.4%**	504	7.4%
U.S. dollars (2014 and 2013 – US$33)	2026	**38**	**7.5%**	34	7.5%
		1,099		1,129	
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. dollars (2014 and 2013 – US$432)	2021 to 2025	**502**	**8.9%**	459	8.9%
GAS TRANSMISSION NORTHWEST CORPORATION					
Senior Unsecured Notes					
U.S. dollars (2014 and 2013 – US$325)	2015 to 2035	**377**	**5.5%**	346	5.5%
TC PIPELINES, LP					
Unsecured Loan					
U.S. dollars (2014 – US$330; 2013 – US$380)	2017	**383**	**1.4%**	404	1.4%
Unsecured Term Loan Facility					
U.S. dollars (2014 – US$500; 2013 – US$500)	2015 to 2018	**580**	**1.4%**	532	1.4%
Senior Unsecured Notes					
U.S. dollars (2014 and 2013 – US$350)	2021	**405**	**4.7%**	372	4.7%
		1,368		1,308	
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. dollars (2014 – US$316; 2013 – US$335)	2018 to 2030	**367**	**7.8%**	356	7.8%
TUSCARORA GAS TRANSMISSION COMPANY					
Senior Secured Notes					
U.S. dollars (2014 – US$20; 2013 – US$24)	2017	**23**	**4.0%**	25	4.0%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes[3]					
U.S. dollars (2014 – US$90; 2013 – US$110)	2018	**105**	**6.1%**	117	6.1%
		24,757		22,865	
Less: Current Portion of Long-Term Debt		**1,797**		973	
		22,960		21,892	

1 Interest rates are the effective interest rates except for those pertaining to Long-Term Debt issued for the Company's Canadian regulated natural gas operations, in which case the weighted average interest rate is presented as approved by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates.

2 Debentures issued by NGTL in the amount of $225 million have retraction provisions that entitle the holders to require redemption of up to eight per cent of the then outstanding principal plus accrued and unpaid interest on specified repayment dates. No redemptions were made in 2014 or 2013.

3 Secured by shipper transportation contracts, existing and new guarantees, letters of credit and collateral requirements.

Principal Repayments

Principal repayments on the Long-Term Debt of the Company for the next five years are approximately as follows:

(millions of Canadian dollars)	2015	2016	2017	2018	2019
Principal repayments on Long-Term Debt	1,797	2,225	846	1,766	1,007

Long-Term Debt Issued

The Company issued Long-Term Debt over the last three years ended December 31 as follows:

(millions of Canadian dollars, unless otherwise noted)

Company	Issue date	Type	Maturity date	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED					
	February 2014	Senior Unsecured Notes	March 2034	US 1,250	4.63%
	October 2013	Senior Unsecured Notes	October 2023	US 625	3.75%
	October 2013	Senior Unsecured Notes	October 2043	US 625	5.00%
	July 2013	Senior Unsecured Notes	June 2016	US 500	Floating
	July 2013	Medium-Term Notes	July 2023	450	3.69%
	July 2013	Medium-Term Notes	November 2041	300	4.55%
	January 2013	Senior Unsecured Notes	January 2016	US 750	0.75%
	August 2012	Senior Unsecured Notes	August 2022	US 1,000	2.50%
	March 2012	Senior Unsecured Notes	March 2015	US 500	0.88%
TC PIPELINES, LP					
	July 2013	Unsecured Term Loan Facility	July 2018	US 500	Floating

Long-Term Debt Retired

The Company retired Long-Term Debt over the last three years ended December 31 as follows:

(millions of Canadian dollars, unless otherwise noted)

Company	Retirement date	Type	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED				
	June 2014	Debentures	125	11.10%
	February 2014	Medium-Term Notes	300	5.05%
	January 2014	Medium-Term Notes	450	5.65%
	August 2013	Senior Unsecured Notes	US 500	5.05%
	June 2013	Senior Unsecured Notes	US 350	4.00%
	May 2012	Senior Unsecured Notes	US 200	8.63%
NOVA GAS TRANSMISSION LTD.				
	June 2014	Debentures	53	11.20%
	December 2012	Debentures	US 175	8.50%

Interest Expense

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Interest on Long-Term Debt	**1,317**	1,216	1,190
Interest on Junior Subordinated Notes (Note 17)	**70**	65	63
Interest on short-term debt	**15**	12	16
Capitalized interest	**(259)**	(287)	(300)
Amortization and other financial charges[1]	**55**	(21)	7
	1,198	985	976

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

The Company made interest payments of $1,123 million in 2014 (2013 – $985 million; 2012 – $966 million) on Long-Term Debt and Junior Subordinated Notes, net of interest capitalized.

16. INCOME TAXES

Provision for Income Taxes

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Current			
Canada	**103**	27	167
Foreign	**42**	16	14
	145	43	181
Deferred			
Canada	**309**	245	69
Foreign	**377**	323	216
	686	568	285
Income Tax Expense	**831**	611	466

Geographic Components of Income

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Canada	**1,146**	1,224	842
Foreign	**1,678**	1,298	1,096
Income before Income Taxes	**2,824**	2,522	1,938

Reconciliation of Income Tax Expense

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
Income before Income Taxes	**2,824**	2,522	1,938
Federal and provincial statutory tax rate	**25.0%**	25.0%	25.0%
Expected income tax expense	**706**	631	485
Income tax differential related to regulated operations	**129**	(13)	41
Higher/(lower) effective foreign tax rates	**25**	33	(12)
Income from equity investments and non-controlling interests	**(38)**	(28)	(27)
Tax legislation change	**–**	(25)	–
Other	**9**	13	(21)
Actual Income Tax Expense	**831**	611	466

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian dollars)	2014	2013
Deferred Income Tax Assets		
Operating loss carryforwards	**1,266**	826
Deferred amounts	**215**	223
Unrealized foreign exchange losses on long-term debt	**140**	–
Financial Instruments	**104**	–
Other	**248**	128
	1,973	1,177
Less: Valuation allowance[1]	**125**	–
	1,848	1,177
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment and PPAs	**5,548**	4,245
Equity investments	**648**	682
Taxes on future revenue requirement	**253**	291
Unrealized foreign exchange gains on long-term debt	**–**	35
Other	**71**	170
	6,520	5,423
Net Deferred Income Tax Liabilities	**4,672**	4,246

[1] A valuation allowance was recorded in 2014 as the Company believes that it is more likely than not that the tax benefit related to the unrealized foreign exchange losses on the long term debt will not be realized in the future.

The above deferred tax amounts have been classified in the Consolidated Balance Sheet as follows:

at December 31 (millions of Canadian dollars)	2014	2013
Deferred Income Tax Assets		
Other Current Assets (Note 5)	**427**	119
Intangible and Other Assets (Note 11)	**180**	225
	607	344
Deferred Income Tax Liabilities		
Accounts Payable and Other (Note 13)	**4**	26
Deferred Income Tax Liabilities	**5,275**	4,564
	5,279	4,590
Net Deferred Income Tax Liabilities	**4,672**	4,246

At December 31, 2014, the Company has recognized the benefit of unused non-capital loss carryforwards of $1,131 million (2013 – $1,026 million) for federal and provincial purposes in Canada, which expire from 2015 to 2034.

At December 31, 2014, the Company has recognized the benefit of unused net operating loss carryforwards of US$2,267 million (2013 – US$1,432 million) for federal purposes in the U.S., which expire from 2028 to 2034.

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Deferred income tax liabilities would have increased at December 31, 2014 by approximately $236 million (2013 – $182 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $109 million, net of refunds, were made in 2014 (2013 – payments, net of refunds, of $202 million; 2012 – refunds, net of payments made, of $190 million).

Reconciliation of Unrecognized Tax Benefit

Below is the reconciliation of the annual changes in the total unrecognized tax benefit:

at December 31 (millions of Canadian dollars)	2014	2013	2012
Unrecognized tax benefits at beginning of year	**23**	49	52
Gross increases – tax positions in prior years	**3**	3	2
Gross decreases – tax positions in prior years	**(8)**	(28)	(6)
Gross increases – tax positions in current year	**1**	2	9
Lapses of statute of limitations	**(1)**	(3)	(8)
Unrecognized tax benefits at end of year	**18**	23	49

TransCanada recognized a favourable income tax adjustment of approximately $25 million due to the enactment of certain Canadian Federal tax legislation in June 2013.

Subject to the results of audit examinations by taxing authorities and other legislative amendments, TransCanada does not anticipate further adjustments to the unrecognized tax benefits during the next twelve months that would have a material impact on its financial statements.

TransCanada and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2009. Substantially all material U.S. federal income tax matters have been concluded for years through 2007 and U.S. state and local income tax matters through 2007.

TransCanada's practice is to recognize interest and penalties related to income tax uncertainties in Income Tax Expense. Income Tax Expense for the year ended December 31, 2014 reflects a $1 million reversal of Interest Expense and nil for penalties (2013 – $1 million increase of Interest Expense and nil for penalties; 2012 – $2 million reversal for Interest Expense and nil for penalties). At December 31, 2014, the Company had $5 million accrued for Interest Expense and nil accrued for penalties (December 31, 2013 – $6 million accrued for Interest Expense and nil accrued for penalties).

17. JUNIOR SUBORDINATED NOTES

Outstanding loan amount (millions of Canadian dollars)	Maturity Date	2014 Outstanding December 31	2014 Effective Interest Rate	2013 Outstanding December 31	2013 Effective Interest Rate
TRANSCANADA PIPELINES LIMITED					
U.S. dollars (2014 and 2013 – US$1,000)	2067	**1,160**	**6.5%**	1,063	6.5%

Junior Subordinated Notes of US$1.0 billion mature in 2067 and bear interest at 6.35 per cent per annum until May 15, 2017, when interest will convert to a floating rate that is reset quarterly to the three-month London Interbank Offered Rate plus 221 basis points. The Company has the option to defer payment of interest for periods of up to 10 years without giving rise to a default or permitting acceleration of payment under the terms of the Junior Subordinated Notes, however, the Company would be prohibited from paying dividends during any such deferral period. The Junior Subordinated Notes are subordinated in right of payment to existing and future senior indebtedness and are effectively subordinated to all indebtedness and other obligations of TCPL. The Junior Subordinated Notes are callable at the Company's option at any time on or after May 15, 2017 at 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption. The Junior Subordinated Notes are callable earlier, in whole or in part, upon the occurrence of certain events and at the Company's option at an amount equal to the greater of 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption and an amount determined by a specified formula in accordance with the terms of the Junior Subordinated Notes.

18. NON-CONTROLLING INTERESTS

The Company's Non-Controlling Interests included in the Consolidated Balance Sheet were as follows:

at December 31 (millions of Canadian dollars)	2014	2013
Non-controlling interest in TC PipeLines, LP	**1,479**	1,323
Non-controlling interest in Portland	**104**	94
Preferred shares of TCPL	**–**	194
	1,583	1,611

The Company's Non-Controlling Interests included in the Consolidated Statement of Income were as follows:

year ended December 31 (millions of Canadian dollars)	**2014**	**2013**	**2012**
Non-controlling interest in TC PipeLines, LP	**136**	93	91
Non-controlling interest in Portland	**15**	12	5
Preferred shares of TCPL	**2**	20	22
	153	125	118

During 2014, the non-controlling interest in TC PipeLines, LP increased from 71.1 per cent to 71.7 per cent due to the issuance of common units in TC PipeLines, LP to non-controlling interests. The non-controlling interest in TC PipeLines, LP from May 2013 to August 2014 was 71.1 per cent and from May 2011 to May 2013 was 66.7 per cent.

The non-controlling interest in Portland as at December 31, 2014 represented the 38.3 per cent interest not owned by TransCanada (2013 and 2012 – 38.3 per cent).

On October 15, 2013, TCPL redeemed all of the four million outstanding 5.60 per cent cumulative redeemable first preferred shares Series U at a price of $50 per share plus $0.5907 representing accrued and unpaid dividends to the redemption date.

On March 5, 2014, TCPL redeemed all of the four million outstanding 5.60 per cent cumulative redeemable first preferred shares Series Y at a price of $50 per share plus $0.2455 representing accrued and unpaid dividends to the redemption date.

In 2014, TransCanada received fees of $3 million from TC PipeLines, LP (2013 and 2012 – $3 million) and $8 million from Portland (2013 and 2012 – $7 million) for services provided.

19. COMMON SHARES

	Number of Shares	**Amount**
	(thousands)	(millions of Canadian dollars)
Outstanding at January 1, 2012	703,861	12,011
Exercise of options	1,600	58
Outstanding at December 31, 2012	705,461	12,069
Exercise of options	1,980	80
Outstanding at December 31, 2013	707,441	12,149
Exercise of options	**1,221**	**53**
Outstanding at December 31, 2014	**708,662**	**12,202**

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

Basic and Diluted Net Income per Share

Net income per share is calculated by dividing Net Income Attributable to Common Shares by the weighted average number of common shares outstanding. The higher weighted average number of shares for the diluted earnings per share calculation is due to options exercisable under TransCanada's Stock Option Plan.

Weighted Average Common Shares Outstanding (millions)	2014	2013	2012
Basic	**708.0**	706.7	704.6
Diluted	**709.6**	707.7	705.7

Stock Options

	Number of Options	Weighted Average Exercise Prices	Options Exercisable
	(thousands)		(thousands)
Outstanding at January 1, 2012	7,100	$35.44	5,165
Granted	1,978	$42.03	
Exercised	(1,600)	$33.13	
Forfeited	(44)	$36.55	
Outstanding at December 31, 2012	7,434	$37.69	4,588
Granted	1,939	$47.09	
Exercised	(1,980)	$36.12	
Outstanding at December 31, 2013	7,393	$40.57	3,954
Granted	**2,292**	**$49.03**	
Exercised	**(1,221)**	**$43.00**	
Outstanding at December 31, 2014	**8,464**	**$43.17**	**4,902**

Stock options outstanding at December 31, 2014 were as follows:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
	(thousands)		(years)	(thousands)		(years)
$30.10 to $36.26	1,410	$33.85	1.7	1,410	$33.85	1.7
$36.90 to $41.65	1,101	$38.24	3.1	1,101	$38.24	3.1
$41.95 to $45.29	1,819	$42.04	4.2	1,464	$42.02	4.2
$47.09	1,842	$47.09	5.1	847	$47.09	5.1
$49.03	2,292	$49.03	6.2	80	$49.03	6.2
	8,464	$43.17	4.3	4,902	$39.81	3.3

An additional 8.2 million common shares were reserved for future issuance under TransCanada's Stock Option Plan at December 31, 2014. The weighted average fair value of options granted to purchase common shares under the Company's Stock Option Plan was determined to be $5.54 for the year ended December 31, 2014 (2013 – $5.74; 2012 – $5.08). The contractual life of options granted is seven years. Options may be exercised at a price determined at the time the option is awarded and vest 33.3 per cent on the anniversary date in each

of the three years following the award. Forfeiture of stock options results from their expiration and, if not previously vested, upon resignation or termination of the option holder's employment.

The Company used a binomial model for determining the fair value of options granted applying the following weighted average assumptions:

year ended December 31	2014	2013	2012
Expected life (years)	**6.0**	6.0	5.9
Interest rate	**1.8%**	1.7%	1.6%
Volatility[1]	**17%**	18%	19%
Dividend yield	**3.8%**	3.7%	4.2%
Forfeiture rate	**5%**	15%	15%

[1] Volatility is derived based on the average of both the historical and implied volatility of the Company's common shares.

The amount expensed for stock options, with a corresponding increase in Additional Paid-In Capital, was $9 million in 2014 (2013 – $6 million; 2012 – $5 million).

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian dollars, unless noted otherwise)	2014	2013	2012
Total intrinsic value of options exercised	**$68**	$25	$18
Fair value of options that have vested	**$113**	$65	$49
Total options vested	**2.0 million**	1.3 million	1.0 million

As at December 31, 2014, the aggregate intrinsic value of the total options exercisable was $85 million and the total intrinsic value of options outstanding was $118 million.

Shareholder Rights Plan

TransCanada's Shareholder Rights Plan is designed to provide the Board with sufficient time to explore and develop alternatives for maximizing shareholder value in the event of a takeover offer for the Company and to encourage the fair treatment of shareholders in connection with any such offer. Attached to each common share is one right that, under certain circumstances, entitles certain holders to purchase two common shares of the Company for the then current market price of one.

20. PREFERRED SHARES

at December 31	Number of Shares Authorized and Outstanding	Current Yield	Annual Dividend Per Share[1]	Redemption Price Per Share[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]	2014	2013
	(thousands)						(millions of Canadian dollars)[6]	(millions of Canadian dollars)[6]
Cumulative First Preferred Shares[5]								
Series 1	9,498	3.27%	$0.82	$25.00	December 31, 2019	Series 2	**233**	539
Series 2	12,502	Floating[7]	Floating	$25.50	December 31, 2019	Series 1	**306**	–
Series 3	14,000	4.00%	$1.00	$25.00	June 30, 2015	Series 4	**343**	343
Series 5	14,000	4.40%	$1.10	$25.00	January 30, 2016	Series 6	**342**	342
Series 7	24,000	4.00%	$1.00	$25.00	April 30, 2019	Series 8	**589**	589
Series 9	18,000	4.25%	$1.06	$25.00	October 30, 2019	Series 10	**442**	–
							2,255	1,813

1 The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend, as declared by the Board with the exception of Series 2 preferred shares. The holders of Series 2 preferred shares are entitled to receive quarterly, floating rate, cumulative, preferential dividends as declared by the Board.

2 Series 2 preferred shares are redeemable by TransCanada at any time for $25.50 per share plus all accrued and unpaid dividends on such redemption date, unless redeemed on a designated redemption option date, or any fifth anniversary thereafter, in which case they are redeemable at $25.00 per share plus all accrued and unpaid dividends. For all other series of preferred shares, TransCanada may, at its option, redeem all or a portion of the outstanding shares for the redemption price per share, plus all accrued and unpaid dividends on the redemption option date and on every fifth anniversary thereafter.

3 The holder will have the right, subject to certain conditions, to convert their first preferred shares of a specified series into first preferred shares of another specified series on the conversion option date and every fifth anniversary thereafter.

4 With the exception of Series 1 preferred shares, if converted each series will be entitled to receive floating rate, cumulative, quarterly, preferential dividends per share at an annualized rate equal to the 90-day Government of Canada Treasury bill rate + 1.92 per cent (Series 2), 1.28 per cent (Series 4), 1.54 per cent (Series 6), 2.38 per cent (Series 8), and 2.35 per cent (Series 10). Holders of Series 1 preferred shares will receive fixed, cumulative, quarterly preferential dividends if converted.

5 With the exception of Series 2 preferred shares, and where the redemption and/or conversion option is not exercised on a designated conversion date, the dividend rate on the fixed rate, cumulative, quarterly, preferential dividends will reset on the redemption and conversion option date and every fifth year thereafter to an annualized rate equal to the then five-year Government of Canada bond yield + 1.92 per cent (Series 1), 1.28 per cent (Series 3), 1.54 per cent (Series 5), 2.38 per cent (Series 7), and 2.35 per cent (Series 9). Holders of Series 2 preferred shares will receive floating rate, cumulative, quarterly, preferential dividends.

6 Net of underwriting commissions and deferred income taxes.

7 Commencing December 31, 2014, the floating quarterly dividend rate for the Series 2 preferred shares is 2.82 per cent and will reset each quarter going forward.

In January 2014, TransCanada completed a public offering of 18 million Series 9 cumulative redeemable first preferred shares at a price of $25.00 per share, resulting in gross proceeds of $450 million.

At December 31, 2014, holders of 12,501,577 Series 1 preferred shares exercised their option to convert to Series 2 preferred shares and receive floating rate, cumulative, quarterly, preferential dividends at a rate equal to the then 90-day Government of Canada Treasury bill rate + 1.92 per cent until December 31, 2019. The floating quarterly dividend rate for the Series 2 preferred shares for the first quarterly floating rate period (being the period from December 31, 2014 to but excluding March 31, 2015) is 2.82 per cent per annum and will reset every quarter. The 9,498,423 Series 1 preferred shares will pay on a quarterly basis, for the five-year period beginning on December 31, 2014 a fixed quarterly dividend based on an annual fixed dividend rate of 3.27 per cent.

21. OTHER COMPREHENSIVE INCOME AND ACCUMULATED OTHER COMPREHENSIVE LOSS

Components of OCI including Non-Controlling Interests and the related tax effects are as follows:

year ended December 31, 2014 (millions of Canadian dollars)	**Before tax amount**	**Income tax recovery/ (expense)**	**Net of tax amount**
Foreign currency translation gains on net investments in foreign operations	**462**	**55**	**517**
Change in fair value of net investment hedges	**(373)**	**97**	**(276)**
Change in fair value of cash flow hedges	**(118)**	**49**	**(69)**
Reclassification to Net Income of gains and losses on cash flow hedges	**(95)**	**40**	**(55)**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**(146)**	**44**	**(102)**
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**25**	**(7)**	**18**
Other comprehensive loss on Equity Investments	**(272)**	**68**	**(204)**
Other comprehensive loss	**(517)**	**346**	**(171)**

year ended December 31, 2013 (millions of Canadian dollars)	**Before tax amount**	**Income tax recovery/ (expense)**	**Net of tax amount**
Foreign currency translation gains on net investments in foreign operations	269	114	383
Change in fair value of net investment hedges	(323)	84	(239)
Change in fair value of cash flow hedges	121	(50)	71
Reclassification to Net Income of gains and losses on cash flow hedges	60	(19)	41
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	96	(29)	67
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	34	(11)	23
Other comprehensive income on Equity Investments	313	(79)	234
Other comprehensive income	570	10	580

year ended December 31, 2012 (millions of Canadian dollars)	**Before tax amount**	**Income tax recovery/ (expense)**	**Net of tax amount**
Foreign currency translation losses on net investments in foreign operations	(97)	(32)	(129)
Change in fair value of net investment hedges	59	(15)	44
Change in fair value of cash flow hedges	61	(13)	48
Reclassification to Net Income of gains and losses on cash flow hedges	219	(81)	138
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	(104)	31	(73)
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	22	–	22
Other comprehensive loss on Equity Investments	(93)	23	(70)
Other comprehensive income/(loss)	67	(87)	(20)

The changes in AOCI by component is as follows:

	Currency translation adjustments	Cash flow hedges	Pension and OPEB plan adjustments	Equity Investments	Total[1]
AOCI Balance at January 1, 2012	(643)	(302)	(236)	(268)	(1,449)
Other comprehensive (loss)/income before reclassifications[2]	(64)	48	(73)	(67)	(156)
Amounts reclassified from Accumulated Other Comprehensive Loss	–	138	22	(3)	157
Net current period other comprehensive (loss)/income	(64)	186	(51)	(70)	1
AOCI Balance at December 31, 2012	(707)	(116)	(287)	(338)	(1,448)
Other comprehensive income before reclassifications[2]	78	71	67	219	435
Amounts reclassified from Accumulated Other Comprehensive Loss	–	41	23	15	79
Net current period other comprehensive income	78	112	90	234	514
AOCI Balance at December 31, 2013	(629)	(4)	(197)	(104)	(934)
Other comprehensive income/(loss) before reclassifications[2]	**111**	**(69)**	**(102)**	**(206)**	**(266)**
Amounts reclassified from Accumulated Other Comprehensive Loss[3]	**–**	**(55)**	**18**	**2**	**(35)**
Net current period other comprehensive income/(loss)	**111**	**(124)**	**(84)**	**(204)**	**(301)**
AOCI Balance at December 31, 2014	**(518)**	**(128)**	**(281)**	**(308)**	**(1,235)**

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.

2 OCI before reclassifications on currency translation adjustments is net of non-controlling interest gains of $130 million in 2014 (2013 – $66 million gains; 2012 – $21 million losses).

3 Losses related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be $95 million ($55 million, net of tax) at December 31, 2014. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

Details about reclassifications out of AOCI into the Consolidated Statement of Income are as follows:

year ended December 31 (millions of Canadian dollars)	Amounts reclassified from accumulated other comprehensive loss[1] 2014	2013	2012	Affected line item in the consolidated statement of income
Cash flow hedges				
Power and Natural Gas	**111**	(44)	(201)	Revenue (Energy)
Interest	**(16)**	(16)	(18)	Interest Expense
	95	(60)	(219)	Total before tax
	(40)	19	81	Income Tax Expense
	55	(41)	(138)	Net of tax
Pension and OPEB plan adjustments				
Amortization of actuarial loss and past service cost[2]	**(25)**	(34)	(22)	[2]
	7	11	–	Income Tax Expense
	(18)	(23)	(22)	Net of tax
Equity Investments				
Equity Income	**(2)**	(20)	5	Income from Equity Investments
	–	5	(2)	Income Tax Expense
	(2)	(15)	3	Net of tax

[1] All amounts in parentheses indicate expenses to the Consolidated Statement of Income.

[2] These Accumulated Other Comprehensive Loss components are included in the computation of net benefit cost. Refer to Note 22 for additional detail.

22. EMPLOYEE POST-RETIREMENT BENEFITS

The Company sponsors DB Plans for its employees. Pension benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment. Upon commencement of retirement, pension benefits in the Canadian DB Plan increase annually by a portion of the increase in the Consumer Price Index. Past service costs are amortized over the expected average remaining service life of employees, which is approximately nine years (2013 and 2012 – nine years).

The Company also provides its employees with a savings plan in Canada, DC Plans consisting of 401(k) Plans in the U.S., and post-employment benefits other than pensions, including termination benefits and life insurance and medical benefits beyond those provided by government-sponsored plans. Past service costs are amortized over the expected average remaining life expectancy of former employees, which was approximately 12 years at December 31, 2014 (2013 – 11 years; 2012 – 12 years). In 2014, the Company expensed $37 million (2013 – $29 million; 2012 – $24 million) for the savings plan and DC Plans.

Total cash payments for employee post-retirement benefits, consisting of cash contributed by the Company were as follows:

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
DB Plans	**73**	79	83
Other post-retirement benefit plans	**6**	6	7
Savings and DC Plans	**37**	29	24
	116	114	114

Current Canadian pension legislation allows for partial funding of solvency requirements over a number of years through letters of credit in lieu of cash contributions, up to certain limits. As such, in addition to the cash contributions noted above, in 2014 the Company provided a $47 million letter of credit to the Canadian DB Plan (2013 – $59 million; 2012 – $48 million), resulting in a total of $181 million provided to the Canadian DB Plan under letters of credit at December 31, 2014.

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2014 and the next required valuation will be as at January 1, 2015.

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian dollars)	2014	2013	2014	2013
Change in Benefit Obligation [1]				
Benefit obligation – beginning of year	**2,224**	2,142	**191**	186
Service cost	**85**	84	**2**	2
Interest cost	**113**	96	**10**	7
Employee contributions	**4**	4	**–**	–
Benefits paid	**(102)**	(83)	**(7)**	(7)
Actuarial loss/(gain)	**302**	(39)	**14**	(2)
Foreign exchange rate changes	**32**	20	**6**	5
Benefit obligation – end of year	**2,658**	2,224	**216**	191
Change in Plan Assets				
Plan assets at fair value – beginning of year	**2,152**	1,825	**35**	32
Actual return on plan assets	**246**	313	**2**	2
Employer contributions[2]	**73**	79	**6**	6
Employee contributions	**4**	4	**–**	–
Benefits paid	**(102)**	(83)	**(7)**	(7)
Foreign exchange rate changes	**25**	14	**3**	2
Plan assets at fair value – end of year	**2,398**	2,152	**39**	35
Funded Status – Plan Deficit	**(260)**	(72)	**(177)**	(156)

1 The benefit obligation for the Company's pension benefit plans represents the projected benefit obligation. The benefit obligation for the Company's other post-retirement benefit plans represents the accumulated post-retirement benefit obligation.

2 Excludes $181 million in letters of credit provided to the Canadian DB Plans for funding purposes (2013 – $134 million).

The amounts recognized in the Company's Balance Sheet for its DB Plans and other post-retirement benefits plans are as follows:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian dollars)	**2014**	**2013**	**2014**	**2013**
Intangible and Other Assets (Note 11)	**–**	–	**14**	16
Accounts Payable and Other (Note 13)	**–**	–	**(7)**	–
Other Long-Term Liabilities (Note 14)	**(260)**	(72)	**(184)**	(172)
	(260)	(72)	**(177)**	(156)

Included in the above benefit obligation and fair value of plan assets were the following amounts for plans that are not fully funded:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian dollars)	**2014**	**2013**	**2014**	**2013**
Projected benefit obligation[1]	**(2,658)**	(2,224)	**(191)**	(172)
Plan assets at fair value	**2,398**	2,152	**–**	–
Funded Status – Deficit	**(260)**	(72)	**(191)**	(172)

[1] The projected benefit obligation for the pension benefit plan differs from the accumulated benefit obligation in that it includes an assumption with respect to future compensation levels.

The accumulated benefit obligation for all DB pension plans at December 31, 2014 is $2,437 million (2013 – $2,039 million).

The funded status based on the accumulated benefit obligation for all DB Plans is as follows:

at December 31 (millions of Canadian dollars)	**2014**	**2013**
Accumulated benefit obligation	**(2,437)**	(2,039)
Plan assets at fair value	**2,398**	2,152
Funded Status – (Deficit)/Surplus	**(39)**	113

Included in the above accumulated benefit obligation and fair value of plan assets are the following amounts in respect of plans that are not fully funded.

at December 31 (millions of Canadian dollars)	**2014**	**2013**
Accumulated benefit obligation	**(715)**	(569)
Plan assets at fair value	**597**	537
Funded Status – Deficit	**(118)**	(32)

The Company pension plans' weighted average asset allocations and target allocations by asset category were as follows:

Asset Category

	Percentage of Plan Assets		Target Allocations[1]
at December 31	**2014**	**2013**	**2014**
Debt securities	**31%**	31%	**25% to 35%**
Equity securities	**69%**	69%	**50% to 70%**
Alternatives	**–**	–	**5% to 15%**
	100%	100%	

[1] Target allocations were revised in November 2013 and the investment mix is being adjusted over time accordingly.

Debt and equity securities include the Company's debt and common shares as follows:

at December 31			Percentage of Plan Assets	
(millions of Canadian dollars)	**2014**	**2013**	**2014**	**2013**
Debt securities	**1**	2	**0.1%**	0.1%
Equity securities	**1**	2	**0.1%**	0.1%

Pension plan assets are managed on a going concern basis, subject to legislative restrictions, and are diversified across asset classes to maximize returns at an acceptable level of risk. Asset mix strategies consider plan demographics and may include traditional equity and debt securities, as well as alternative assets such as infrastructure, private equity, real estate and derivatives to diversify risk. Derivatives are not used for speculative purposes and the use of leveraged derivatives is prohibited.

All investments are measured at fair value using market prices. Where the fair value cannot be readily determined by reference to generally available price quotations, the fair value is determined by considering the discounted cash flows on a risk-adjusted basis and by comparison to similar assets which are publicly traded. In Level I, the fair value of assets is determined by reference to quoted prices in active markets for identical assets that the Company has the ability to access at the measurement date. In Level II, the fair value of assets is determined using valuation techniques, such as option pricing models and extrapolation using significant inputs, which are observable directly or indirectly. In Level III, the fair value of assets is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement. For further information on the fair value hierarchy, refer to Note 23.

The following table presents plan assets for DB Plans and other post-retirement benefits measured at fair value, which have been categorized into the three categories based on a fair value hierarchy.

at December 31	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total		Percentage of Total Portfolio	
(millions of Canadian dollars)	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**
Asset Category										
Cash and Cash Equivalents	**20**	17	**–**	–	**–**	–	**20**	17	**1%**	1%
Equity Securities:										
Canadian	**361**	474	**142**	170	**–**	–	**503**	644	**21%**	29%
U.S.	**516**	423	**35**	37	**–**	–	**551**	460	**23%**	21%
International	**218**	36	**147**	330	**–**	–	**365**	366	**15%**	17%
Global	**–**	–	**141**	14	**–**	–	**141**	14	**6%**	1%
Emerging	**7**	–	**80**	–	**–**	–	**87**	–	**3%**	–
Fixed Income Securities:										
Canadian Bonds:										
Federal	**–**	–	**218**	190	**–**	–	**218**	190	**9%**	9%
Provincial	**–**	–	**180**	154	**–**	–	**180**	154	**7%**	7%
Municipal	**–**	–	**7**	6	**–**	–	**7**	6	**–**	–
Corporate	**–**	–	**76**	77	**–**	–	**76**	77	**3%**	3%
U.S. Bonds:										
State	**–**	–	**47**	33	**–**	–	**47**	33	**2%**	2%
Corporate	**–**	–	**59**	48	**–**	–	**59**	48	**2%**	2%
International:										
Corporate	**–**	–	**14**	20	**–**	–	**14**	20	**1%**	1%
Mortgage Backed	**–**	–	**39**	26	**–**	–	**39**	26	**2%**	1%
Other Investments:										
Private Equity Funds	**–**	–	**–**	–	**13**	18	**13**	18	**–**	1%
Funds held on deposit	**117**	114			**–**	–	**117**	114	**5%**	5%
	1,239	1,064	**1,185**	1,105	**13**	18	**2,437**	2,187	**100%**	100%

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

(millions of Canadian dollars, pre-tax)	Private Equity Funds
Balance at December 31, 2012	19
Purchases and Sales	(4)
Realized and unrealized gains	3
Balance at December 31, 2013	18
Purchases and sales	**(7)**
Realized and unrealized gains	**2**
Balance at December 31, 2014	**13**

The Company's expected funding contributions in 2015 are approximately $70 million for the DB Plans, approximately $7 million for the other post-retirement benefit plans and approximately $36 million for the savings plan and DC Plans. The Company expects to provide an additional estimated $35 million letter of credit to the Canadian DB Plan for the funding of solvency requirements.

The following are estimated future benefit payments, which reflect expected future service:

(millions of Canadian dollars)	Pension Benefits	Other Post-Retirement Benefits
2015	102	8
2016	108	8
2017	114	9
2018	120	9
2019	127	10
2020 to 2024	728	51

The rate used to discount pension and other post-retirement benefit plan obligations was developed based on a yield curve of corporate AA bond yields at December 31, 2014. This yield curve is used to develop spot rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other post-retirement obligations were matched to the corresponding rates on the spot rate curve to derive a weighted average discount rate.

The significant weighted average actuarial assumptions adopted in measuring the Company's benefit obligations were as follows:

	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
at December 31	**2014**	**2013**	**2014**	**2013**
Discount rate	**4.15%**	4.95%	**4.20%**	5.00%
Rate of compensation increase	**3.15%**	3.15%	**–**	–

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan costs were as follows:

	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
year ended December 31	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**
Discount rate	**4.95%**	4.35%	5.05%	**5.00%**	4.35%	5.10%
Expected long-term rate of return on plan assets	**6.90%**	6.70%	6.70%	**4.60%**	4.60%	6.40%
Rate of compensation increase	**3.15%**	3.15%	3.15%	**–**	–	–

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and estimating future levels and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in determining the overall expected rate of return. The discount rate is based on market interest rates of high-quality bonds that match the timing and benefits expected to be paid under each plan.

A 7.5 per cent average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2015 measurement purposes. The rate was assumed to decrease gradually to five per cent by

2020 and remain at this level thereafter. A one per cent change in assumed health care cost trend rates would have the following effects:

(millions of Canadian dollars)	Increase	Decrease
Effect on total of service and interest cost components	1	(1)
Effect on post-retirement benefit obligation	14	(12)

The Company's net benefit cost is as follows:

at December 31	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
(millions of Canadian dollars)	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**
Service cost	**85**	84	66	**2**	2	2
Interest cost	**113**	96	94	**10**	7	8
Expected return on plan assets	**(139)**	(120)	(113)	**(2)**	(2)	(2)
Amortization of actuarial loss	**21**	30	18	**2**	2	1
Amortization of past service cost	**2**	2	2	**–**	–	1
Amortization of regulatory asset	**18**	30	19	**1**	1	1
Amortization of transitional obligation related to regulated business	**–**	–	–	**2**	2	2
Net Benefit Cost Recognized	**100**	122	86	**15**	12	13

Pre-tax amounts recognized in AOCI were as follows:

	2014		2013		2012	
at December 31 (millions of Canadian dollars)	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Net loss	**354**	**40**	236	32	362	33
Prior service cost	**2**	**1**	3	1	5	2
	356	**41**	239	33	367	35

The estimated net loss and prior service cost for the DB Plans that will be amortized from AOCI into net periodic benefit cost in 2015 are $27 million and $2 million, respectively. The estimated net loss and prior service cost for the other post-retirement plans that will be amortized from AOCI into net periodic benefit cost in 2015 is $2 million and nil, respectively.

Pre-tax amounts recognized in OCI were as follows:

	2014		2013		2012	
at December 31 (millions of Canadian dollars)	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Amortization of net loss from AOCI to OCI	**(21)**	**(2)**	(30)	(2)	(19)	(1)
Amortization of prior service costs from AOCI to OCI	**(2)**	**–**	(2)	–	(2)	–
Funded status adjustment	**137**	**9**	(96)	–	99	5
	114	**7**	(128)	(2)	78	4

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TransCanada has exposure to market risk and counterparty credit risk, and has strategies, policies and limits in place to manage the impact of these risks on 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. Market risk and counterparty credit risk are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by the Company's risk management and internal audit groups. The Board of Directors' Audit Committee oversees how management monitors compliance with market risk and counterparty credit 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 energy infrastructure projects, purchases and sells energy commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. Certain of these activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which may 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 assist in managing the exposure to market risk that results from these activities. These derivative contracts may 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 manage 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 manage the impact of changes in interest rates, foreign exchange rates and commodity prices.
- Options – contractual agreements that 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 manage the impact of changes in interest rates, foreign exchange rates and commodity prices.

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 manage 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 manage 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 through purchased contracts, thereby reducing the Company's exposure to fluctuating commodity prices.
- The Company enters into offsetting or back-to-back positions using derivative 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.

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. Unrealized gains and losses on fair value adjustments recorded each period on these forward contracts are not necessarily 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, Liquids 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. As the Company's U.S. dollar-denominated operations continue to grow, exposure to changes in currency rates increases; some of this foreign exchange impact is partially offset by interest expense on U.S. dollar-denominated debt and by using foreign exchange derivatives.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to other U.S. dollar-denominated transactions including those that may arise on some of the Company's regulated assets, in which case certain of the realized gains and losses on these derivatives would be deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers.

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 Foreign Operations
The Company hedges its net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, foreign exchange forward contracts and foreign exchange options.

U.S. Dollar-Denominated Debt Designated as a Net Investment Hedge

at December 31 (millions of Canadian dollars, unless noted otherwise)	**2014**	**2013**
Carrying value	**17,000 (US 14,700)**	14,200 (US 13,400)
Fair value	**19,000 (US 16,400)**	16,000 (US 15,000)

Derivatives Designated as a Net Investment Hedge

	2014		**2013**	
at December 31 (millions of Canadian dollars, unless noted otherwise)	**Fair Value[1]**	**Notional or Principal Amount**	**Fair Value[1]**	**Notional or Principal Amount**
U.S. dollar cross-currency interest rate swaps (maturing 2015 to 2019)[2]	**(431)**	**US 2,900**	(201)	US 3,800
U.S. dollar foreign exchange forward contracts (maturing 2015)	**(28)**	**US 1,400**	(11)	US 850
	(459)	**US 4,300**	(212)	US 4,650

1 Fair values approximate carrying values.

2 In 2014, net realized gains of $21 million (2013 – gains of $29 million) related to the interest component of cross-currency swap settlements are included in Interest Expense.

The balance sheet classification of the fair value of derivatives used to hedge the Company's net investment in foreign operations is as follows:

at December 31 (millions of Canadian dollars)	2014	2013
Other Current Assets (Note 5)	**5**	5
Intangible and Other Assets (Note 11)	**1**	–
Accounts Payable and Other (Note 13)	**(155)**	(50)
Other Long-Term Liabilities (Note 14)	**(310)**	(167)
	(459)	(212)

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 related contract or agreement with the Company.

The Company manages its exposure to this potential loss by using recognized credit management techniques, including:

- Dealing with creditworthy counterparties – a significant amount of the Company's credit exposure is with investment grade counterparties or, if not, is generally partially supported by financial assurances from investment grade parties
- Setting limits on the amount TransCanada can transact with any one counterparty – the Company monitors and manages the concentration of risk exposure with any one counterparty, and reduces the exposure when needed and when it is allowed under the terms of the contracts
- Using contract netting arrangements and obtaining financial assurances such as guarantees, letters of credit or cash when deemed necessary.

There is no guarantee that these techniques will protect the Company from material losses.

TransCanada's maximum counterparty credit exposure with respect to financial instruments at December 31, 2014, 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 Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At December 31, 2014, there were no significant amounts past due or impaired, and there were no significant credit losses during the year. The Company had a credit risk concentration due from a counterparty of $258 million (US$222 million) and $240 million (US$225 million) at December 31, 2014 and 2013, respectively. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's investment grade parent company.

TransCanada has significant credit and performance exposures to financial institutions as they hold cash deposits and provide committed credit lines and letters of credit that help manage our exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

Financial Instruments

All financial instruments, including both derivative and non-derivative instruments, are recorded on the balance sheet at fair value unless they were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's normal purchase and normal sales exemptions and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain accounting exemptions.

Fair Value of Non-Derivative Financial Instruments

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 is estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data service providers.

The fair value of available for sale assets has been calculated using quoted market prices where available. Credit risk has been taken into consideration when calculating the fair value of non-derivative instruments.

Certain non-derivative financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Intangible and Other Assets, Notes Payable, Accounts Payable and Other, Accrued Interest and Other Long-Term Liabilities have carrying amounts that approximates their fair value due to the nature of the item or the short time to maturity and would be classified in Level II of the fair value hierarchy.

Balance Sheet Presentation of Non-Derivative Financial Instruments
The following table details the fair value of the non-derivative financial instruments, excluding those where carrying amounts equal fair value, and would be classified in Level II of the fair value hierarchy:

	2014		2013	
at December 31 (millions of Canadian dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Notes receivable and other[1]	**213**	**263**	226	269
Available for sale assets[2]	**62**	**62**	47	47
Current and Long-Term Debt[3,4] (Note 15)	**(24,757)**	**(28,713)**	(22,865)	(26,134)
Junior Subordinated Notes (Note 17)	**(1,160)**	**(1,157)**	(1,063)	(1,093)
	(25,642)	**(29,545)**	(23,655)	(26,911)

1 Notes receivable are included in Other Current Assets and Intangible and Other Assets on the Consolidated Balance Sheet.

2 Available for sale assets are included in Intangible and Other Assets on the Consolidated Balance Sheet.

3 Long-Term Debt is recorded at amortized cost, except for US$400 million (2013 – US$200 million) that is attributed to hedged risk and recorded at fair value.

4 Consolidated Net Income in 2014 included losses of $3 million (2013 – losses of $5 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$400 million of Long-Term Debt at December 31, 2014 (2013 – US$200 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Fair Value of Derivative Instruments
The fair value of foreign exchange and interest rate derivatives have been calculated using the income approach which uses year-end market rates and applies a discounted cash flow valuation model. The fair value of power and natural gas derivatives and available for sale assets 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. Credit risk has been taken into consideration when calculating the fair value of derivative instruments.

In some cases, even though the derivatives are considered to be effective economic hedges, they do not meet the specific criteria for hedge accounting treatment or are not designated as a hedge 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 earnings because the fair value of the derivative instruments can fluctuate significantly from period to period.

Balance Sheet Presentation of Derivative Instruments
The balance sheet classification of the fair value of the derivative instruments is as follows:

at December 31 (millions of Canadian dollars)	**2014**	**2013**
Other Current Assets (Note 5)	**409**	395
Intangible and Other Assets (Note 11)	**93**	112
Accounts Payable and Other (Note 13)	**(749)**	(357)
Other Long-Term Liabilities (Note 14)	**(411)**	(255)
	(658)	(105)

2014 Derivative Instruments Summary

The following summary does not include hedges of the net investment in foreign operations.

(millions of Canadian dollars, unless noted otherwise)	Power	Natural Gas	Foreign Exchange	Interest
Derivative Instruments Held for Trading [1]				
Fair Values[2]				
Assets	**$362**	**$69**	**$1**	**$4**
Liabilities	**($391)**	**($103)**	**($32)**	**($4)**
Notional Values				
Volumes[3]				
Purchases	**42,097**	**60**	**–**	**–**
Sales	**35,452**	**38**	**–**	**–**
U.S. dollars	**–**	**–**	**US 1,374**	**US 100**
Net unrealized losses in the year[4]	**($5)**	**($35)**	**($20)**	**$–**
Net realized (losses)/gains in the year[4]	**($39)**	**$11**	**($28)**	**$–**
Maturity dates	**2015-2019**	**2015-2020**	**2015**	**2015-2016**
Derivative Instruments in Hedging Relationships [5,6]				
Fair Values[2]				
Assets	**$57**	**$–**	**$–**	**$3**
Liabilities	**($163)**	**$–**	**$–**	**($2)**
Notional Values				
Volumes[3]				
Purchases	**11,120**	**–**	**–**	**–**
Sales	**3,977**	**–**	**–**	**–**
U.S. dollars	**–**	**–**	**–**	**US 550**
Net realized gains in the year[4]	**$130**	**$–**	**$–**	**$4**
Maturity dates	**2015-2019**	**–**	**–**	**2015-2018**

1 The majority of derivative instruments held for trading have been entered into for risk management purposes and all 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 value equals carrying value.

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 instruments used to purchase and sell power and natural gas are included net in Energy Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative instruments held for trading are included net 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 Energy 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 instruments designated as fair value hedges with a fair value of $3 million and a notional amount of US$400 million. In 2014, net realized gains on fair value hedges were $7 million and were included in Interest Expense. In 2014, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

6 In 2014, 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.

2013 Derivative Instruments Summary

The following summary does not include hedges of the net investment in foreign operations.

(millions of Canadian dollars, unless noted otherwise)	Power	Natural Gas	Foreign Exchange	Interest
Derivative Instruments Held for Trading [1]				
Fair Values[2]				
Assets	$265	$73	$–	$8
Liabilities	($280)	($72)	($12)	($7)
Notional Values				
Volumes[3]				
Purchases	29,301	88	–	–
Sales	28,534	60	–	–
Canadian dollars	–	–	–	400
U.S. dollars	–	–	US 1,015	US 100
Net unrealized gains/(losses) in the year[4]	$19	$17	($10)	$–
Net realized losses in the year[4]	($49)	($13)	($9)	$–
Maturity dates	2014-2017	2014-2016	2014	2014-2016
Derivative Instruments in Hedging Relationships [5,6]				
Fair Values[2]				
Assets	$150	$–	$–	$6
Liabilities	($22)	$–	($1)	($1)
Notional Values				
Volumes[3]				
Purchases	9,758	–	–	–
Sales	6,906	–	–	–
U.S. dollars	–	–	US 16	US 350
Net realized (losses)/gains in the year[4]	($19)	($2)	$–	$5
Maturity dates	2014-2018	–	2014	2015-2018

1 The majority of derivative instruments held for trading have been entered into for risk management purposes and all 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 value equals carrying value.

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 instruments used to purchase and sell power and natural gas are included net in Energy Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative instruments held for trading are included net 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 Energy 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 instruments designated as fair value hedges with a fair value of $5 million and a notional amount of US$200 million. In 2013, net realized gains on fair value hedges were $6 million and were included in Interest Expense. In 2013, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

6 In 2013, 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.

Derivatives in Cash Flow Hedging Relationships

The following table presents the components of OCI (Note 21) related to derivatives in cash flow hedging relationships:

year ended December 31 (millions of Canadian dollars, pre-tax)	2014	2013
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Power	**(126)**	117
Natural Gas	**(2)**	(1)
Foreign Exchange	**10**	5
	(118)	121
Reclassification of (losses)/gains on derivative instruments from AOCI to Net Income (effective portion)[1]		
Power[2]	**(114)**	40
Natural Gas[2]	**3**	4
Interest[3]	**16**	16
	(95)	60
(Losses)/gains on derivative instruments recognized in Net Income (ineffective portion)		
Power	**(13)**	8
	(13)	8

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI.

2 Reported within Energy Revenues on the Consolidated Statement of Income.

3 Reported within Interest Expense on the Consolidated Statement of Income.

Offsetting of Derivative Instruments

The Company enters into derivative contracts with the right to offset in the normal course of business as well as in the event of default. TransCanada has no master netting agreements, however, similar contracts are entered into containing rights of offset. The Company has elected to present the fair value of derivative instruments with the right to offset on a gross basis in the balance sheet. The following table shows the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis:

at December 31, 2014 (millions of Canadian dollars)	Gross derivative instruments presented on the balance sheet	Amounts available for offset[1]	Net amounts
Derivative – Asset			
Power	**419**	**(330)**	**89**
Natural gas	**69**	**(57)**	**12**
Foreign exchange	**7**	**(7)**	**–**
Interest	**7**	**(1)**	**6**
	502	**(395)**	**107**
Derivative – Liability			
Power	**(554)**	**330**	**(224)**
Natural gas	**(103)**	**57**	**(46)**
Foreign exchange	**(497)**	**7**	**(490)**
Interest	**(6)**	**1**	**(5)**
	(1,160)	**395**	**(765)**

1 Amounts available for offset do not include cash collateral pledged or received.

The following table shows the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis as at December 31, 2013:

at December 31, 2013 (millions of Canadian dollars)	**Gross derivative instruments presented on the balance sheet**	**Amounts available for offset[1]**	**Net amounts**
Derivative – Asset			
Power	415	(277)	138
Natural gas	73	(61)	12
Foreign exchange	5	(5)	–
Interest	14	(2)	12
	507	(345)	162
Derivative – Liability			
Power	(302)	277	(25)
Natural gas	(72)	61	(11)
Foreign exchange	(230)	5	(225)
Interest	(8)	2	(6)
	(612)	345	(267)

[1] Amounts available for offset do not include cash collateral pledged or received.

With respect to all financial arrangements, including the derivative instruments presented above as at December 31, 2014, the Company had provided cash collateral of $459 million (2013 – $67 million) and letters of credit of $26 million (2013 – $85 million) to its counterparties. The Company held $1 million (2013 – $11 million) in cash collateral and $1 million (2013 – $32 million) in letters of credit from counterparties on asset exposures at December 31, 2014.

Credit Risk Related Contingent Features of Derivative Instruments

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, 2014, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $15 million (2013 – $16 million), for which the Company has provided collateral in the normal course of business of nil (2013 – nil). If the credit-risk-related contingent features in these agreements were triggered on December 31, 2014, the Company would have been required to provide additional collateral of $15 million (2013 – $16 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative 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.

Levels	How fair value has been determined
Level I	Quoted prices in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date.
Level II	Valuation based on the extrapolation of inputs, other than quoted prices included within Level I, for which all significant inputs are observable directly or indirectly. Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers. This category includes interest rate and foreign exchange derivative assets and liabilities where fair value is determined using the income approach and power and natural gas commodity derivatives where fair value is determined using the market approach. Transfers between Level I and Level II would occur when there is a change in market circumstances.
Level III	Valuation of assets and liabilities are measured using a market approach based on extrapolation of inputs that are unobservable or where observable data does not support a significant portion of the derivatives fair value. This category includes long-dated commodity transactions in certain markets where liquidity is low and inputs may include long-term broker quotes. Long-term electricity prices may also be estimated using a third-party modeling tool which takes into account physical operating characteristics of generation facilities in the markets in which the Company operates. Model inputs include market fundamentals such as fuel prices, power supply additions and retirements, power demand, seasonal hydro conditions and transmission constraints. Long-term North American natural gas prices might be estimated on a view of future natural gas supply and demand, as well as exploration and development costs. Significant decreases in fuel prices or demand for electricity or natural gas, or increases in the supply of electricity or natural gas, small number of transactions in markets with lower liquidity are expected to or may result in a lower fair value measurement of contracts included in Level III. 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 significant inputs are considered to be observable. As contracts near maturity and observable market data becomes available, they are transferred out of Level III and into Level II.

The fair value of the Company's assets and liabilities measured on a recurring basis, including both current and non-current portions for 2014, are categorized as follows:

at December 31, 2014 (millions of Canadian dollars, pre-tax)	Quoted prices in active markets Level I[1]	Significant other observable inputs Level II[1]	Significant unobservable inputs Level III[1]	Total
Derivative Instrument Assets:				
Power commodity contracts	**–**	**417**	**2**	**419**
Natural gas commodity contracts	**40**	**24**	**5**	**69**
Foreign exchange contracts	**–**	**7**	**–**	**7**
Interest rate contracts	**–**	**7**	**–**	**7**
Derivative Instrument Liabilities:				
Power commodity contracts	**–**	**(551)**	**(3)**	**(554)**
Natural gas commodity contracts	**(86)**	**(17)**	**–**	**(103)**
Foreign exchange contracts	**–**	**(497)**	**–**	**(497)**
Interest rate contracts	**–**	**(6)**	**–**	**(6)**
Non-Derivative Financial Instruments:				
Available for sale assets	**–**	**62**	**–**	**62**
	(46)	**(554)**	**4**	**(596)**

[1] There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2014.

The fair value of the Company's assets and liabilities measured on a recurring basis, including both current and non-current portions for 2013, are categorized as follows:

at December 31, 2013 (millions of Canadian dollars, pre-tax)	Quoted prices in active markets Level I[1]	Significant other observable inputs Level II[1]	Significant unobservable inputs Level III[1]	Total
Derivative Instrument Assets:				
Power commodity contracts	–	411	4	415
Natural gas commodity contracts	48	25	–	73
Foreign exchange contracts	–	5	–	5
Interest rate contracts	–	14	–	14
Derivative Instrument Liabilities:				
Power commodity contracts	–	(299)	(3)	(302)
Natural gas commodity contracts	(50)	(22)	–	(72)
Foreign exchange contracts	–	(230)	–	(230)
Interest rate contracts	–	(8)	–	(8)
Non-Derivative Financial Instruments:				
Available for sale assets	–	47	–	47
	(2)	(57)	1	(58)

[1] There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2013.

The following table presents the net change in fair value of derivative assets and liabilities classified as Level III of the fair value hierarchy:

(millions of Canadian dollars, pre-tax)	2014	2013
Balance at beginning of year	**1**	(2)
Transfers out of Level III	**–**	(2)
Total gains/(losses) included in Net Income	**3**	(1)
Total gains included in OCI	**–**	6
Balance at end of year [1]	**4**	1

[1] Energy Revenues include unrealized gains attributed to derivatives in the Level III category that were still held at December 31, 2014 of $3 million (2013 – nil).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $1 million decrease or increase, respectively, in the fair value of outstanding derivative instruments included in Level III as at December 31, 2014.

24. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian dollars)	2014	2013	2012
(Increase)/decrease in Accounts Receivable	**(189)**	(54)	67
(Increase)/decrease in Inventories	**(28)**	(30)	27
(Increase)/decrease in Other Current Assets	**(385)**	40	66
Increase/(decrease) in Accounts Payable and Other	**377**	(290)	127
Increase in Accrued Interest	**36**	8	–
(Increase)/Decrease in Operating Working Capital	**(189)**	(326)	287

25. ACQUISITIONS AND DISPOSITIONS

Energy

Ontario Solar

As part of a purchase agreement with Canadian Solar Solutions Inc. signed in 2011, TransCanada completed the acquisition of three Ontario solar facilities for $181 million in September 2014 and acquired a fourth facility for $60 million in December 2014. In 2013, TransCanada completed the acquisition of four solar facilities for $216 million. The Company's total investment in the eight solar facilities is $457 million. All power produced by the solar facilities is sold under 20-year PPAs with the Ontario Power Authority.

Cancarb
On April 15, 2014, TransCanada sold Cancarb Limited and its related power generation for aggregate gross proceeds of $190 million. Please refer to Note 6 for further information on the sale.

CrossAlta
In December 2012, TransCanada purchased BP's 40 per cent interest in the assets of the Crossfield Gas Storage facility and BP's interest in CrossAlta Gas Storage & Services Ltd. (collectively CrossAlta) for $214 million in cash, net of cash acquired, resulting in the Company owning and operating 100 per cent of these operations.

The Company measured the assets and liabilities acquired at fair value and the transaction resulted in no goodwill. Upon completion of the acquisition, TransCanada began consolidating CrossAlta. Prior to the acquisition, TransCanada applied equity accounting to its 60 per cent ownership interest in CrossAlta.

Natural Gas Pipelines

TC PipeLines, LP
On October 1, 2014, TransCanada completed the sale of its remaining 30 per cent interest in Bison Pipeline LLC (Bison LLC) to TC PipeLines, LP for an aggregate purchase price of US$215 million.

In July 2013, TransCanada completed the sale of a 45 per cent interest in each of GTN LLC and Bison LLC to TC PipeLines, LP for an aggregate purchase price of US$1.05 billion, which included US$146 million of long-term debt for 45 per cent of GTN LLC debt outstanding, plus normal closing adjustments. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively.

In May 2013, TC PipeLines, LP completed a public offering of 8,855,000 common units at a price of US$43.85 per unit, resulting in gross proceeds of approximately US$388 million and net proceeds of US$373 million after unit issuance costs. TransCanada contributed approximately US$8 million to maintain its two per cent general partnership interest and did not purchase any other units. Upon completion of this offering, TransCanada's ownership interest in TC PipeLines, LP decreased from 33.3 per cent to 28.9 per cent and an after-tax dilution gain of $29 million ($47 million pre-tax) was recorded in Additional Paid-In Capital.

Gas Pacifico/INNERGY
On November 26, 2014, TransCanada sold its 30 per cent equity investments in Gas Pacifico and INNERGY for aggregate gross proceeds of $9 million and recognized a gain of $9 million ($8 million after tax).

26. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Operating Leases

Future annual payments, net of sub-lease receipts, under the Company's operating leases for various premises, services and equipment are approximately as follows:

year ended December 31 (millions of Canadian dollars)	Minimum Lease Payments	Amounts Recoverable under Sub-leases	Net Payments
2015	348	48	300
2016	335	47	288
2017	335	48	287
2018	250	27	223
2019	232	23	209
2020 and thereafter	407	20	387
	1,907	213	1,694

The operating lease agreements for premises, services and equipment expire at various dates through 2052, with an option to renew certain lease agreements for periods of one year to five years. Net rental expense on operating leases in 2014 was $114 million (2013 – $98 million; 2012 – $84 million).

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. Fixed payments under these PPAs have been included in the above operating leases table. Variable payments have been excluded as these payments are dependent upon plant availability and other factors. TransCanada's share of payments under the PPAs in 2014 was $391 million (2013 – $242 million; 2012 – $238 million). The generating capacities and expiry dates of the PPAs are as follows:

	MW	Expiry Date
Sundance A	560	December 31, 2017
Sheerness	756	December 31, 2020

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business.

Other Commitments

Capital expenditure commitments include obligations related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts.

At December 31, 2014, TransCanada was committed to Natural Gas Pipelines capital expenditures totaling approximately $0.9 billion (2013 – $1.3 billion), primarily related to construction costs related to the Mexican and other natural gas pipeline projects.

At December 31, 2014, the Company was committed to Liquids Pipelines capital expenditures totaling approximately $1.8 billion (2013 – $2.5 billion), primarily related to construction costs of Keystone XL, Grand Rapids and Northern Courier.

At December 31, 2014, the Company was committed to Energy capital expenditures totaling approximately $0.2 billion (2013 – $0.1 billion), primarily related to capital costs of the Napanee Generating Station.

Contingencies

TransCanada is subject to laws and regulations governing environmental quality and pollution control. As at December 31, 2014, the Company had accrued approximately $31 million (2013 – $32 million; 2012 – $37 million) related to operating facilities, which represents the present value of the estimated future 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.

Guarantees

TransCanada and its joint venture partner on Bruce Power, BPC Generation Infrastructure Trust (BPC), have each severally guaranteed certain contingent financial obligations of Bruce B related to a lease agreement and contractor and supplier services. In addition, TransCanada and BPC have each severally guaranteed one-half of certain contingent financial obligations of Bruce A related to a sublease agreement and certain other financial obligations. 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. 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.

The carrying value of these guarantees has been included in Other Long-Term Liabilities. Information regarding the Company's guarantees is as follows:

		2014		2013	
year ended December 31 (millions of Canadian dollars)	**Term**	**Potential Exposure[1]**	**Carrying Value**	**Potential Exposure[1]**	**Carrying Value**
Bruce Power	Ranging to 2019[2]	634	6	740	8
Other jointly owned entities	Ranging to 2040	104	14	51	10
		738	20	791	18

1 TransCanada's share of the potential estimated current or contingent exposure.

2 Except for one guarantee with no termination date.

27. SUBSEQUENT EVENTS

On January 12, 2015 TCPL completed its offering of US$500 million 1.88 per cent Senior Notes due January 12, 2018 and US$250 million Floating Rate Senior Notes due January 12, 2018.

Supplementary information

SELECTED QUARTERLY AND ANNUAL CONSOLIDATED FINANCIAL DATA

	First	Second	Third	Fourth	Annual
Toronto Stock Exchange (Stock trading symbol TRP)					
2014 (dollars)					
High	**50.97**	**51.89**	**63.86**	**58.18**	**63.86**
Low	**47.14**	**49.34**	**50.38**	**49.30**	**47.14**
Close	**50.25**	**50.93**	**57.68**	**57.10**	**57.10**
Volume (millions of shares)	**58.6**	**58.9**	**104.7**	**115.0**	**337.2**
2013 (dollars)					
High	50.08	51.21	48.48	48.93	51.21
Low	46.80	44.62	44.75	43.94	43.94
Close	48.50	45.28	45.25	48.54	48.54
Volume (millions of shares)	76.9	85.8	64.3	68.9	295.9
2012 (dollars)					
High	44.75	43.80	46.29	47.44	47.44
Low	40.34	41.47	42.73	43.16	40.34
Close	42.83	42.67	44.74	47.02	47.02
Volume (millions of shares)	95.4	79.3	78.5	66.0	319.2
2011 (dollars)					
High	39.64	43.72	43.23	44.74	44.74
Low	36.10	38.95	37.00	39.25	36.10
Close	39.31	42.35	42.54	44.53	44.53
Volume (millions of shares)	106.9	85.9	107.4	120.6	420.8
2010 (dollars)					
High	37.87	38.16	38.88	39.28	39.28
Low	33.96	30.01	35.50	35.49	30.01
Close	37.22	35.61	38.17	37.99	37.99
Volume (millions of shares)	91.8	93.5	89.2	108.1	382.6
New York Stock Exchange (Stock trading symbol TRP)					
2014 (U.S. dollars)					
High	**45.81**	**48.13**	**58.40**	**51.84**	**58.40**
Low	**42.21**	**44.78**	**47.24**	**43.71**	**42.21**
Close	**45.52**	**47.72**	**51.53**	**49.10**	**49.10**
Volume (millions of shares)	**31.9**	**29.5**	**88.2**	**99.5**	**249.0**
2013 (U.S. dollars)					
High	49.64	49.65	46.79	46.45	49.65
Low	45.80	42.39	42.59	42.41	42.39
Close	47.89	43.11	43.94	45.66	45.66
Volume (millions of shares)	33.3	38.2	30.3	27.9	129.7
2012 (U.S. dollars)					
High	45.07	44.50	47.02	47.78	47.78
Low	39.74	39.87	41.68	43.54	39.74
Close	43.00	41.90	45.50	47.32	47.32
Volume (millions of shares)	39.7	29.2	20.1	20.0	109.0
2011 (U.S. dollars)					
High	40.76	45.09	44.08	44.38	45.09
Low	36.12	40.37	37.29	37.58	36.12
Close	40.53	43.84	40.49	43.67	43.67
Volume (millions of shares)	30.3	23.8	51.6	48.5	154.2
2010 (U.S. dollars)					
High	37.11	38.01	37.75	38.59	38.59
Low	31.58	25.80	32.86	34.77	25.80
Close	36.76	33.43	37.12	38.04	38.04
Volume (millions of shares)	17.8	23.8	19.7	23.6	84.9

Five year financial highlights

(millions of Canadian dollars, except where indicated)	2014	2013	2012	2011	2010
Income Statement					
Revenues	**10,185**	8,797	8,007	7,839	6,852
EBITDA					
Natural Gas Pipelines	**3,250**	2,908	2,741	2,875	2,670
Liquids Pipelines	**1,059**	752	698	587	—
Energy	**1,360**	1,406	862	1,119	976
Corporate	**(127)**	(108)	(97)	(86)	(99)
	5,542	4,958	4,204	4,495	3,547
Depreciation	**(1,611)**	(1,485)	(1,375)	(1,328)	(1,160)
EBIT	**3,931**	3,473	2,829	3,167	2,387
Interest expense and other	**(1,107)**	(951)	(891)	(882)	(607)
Income taxes	**(831)**	(611)	(466)	(575)	(387)
Net Income	**1,993**	1,911	1,472	1,710	1,393
Net income attributable to non-controlling interests	**(153)**	(125)	(118)	(129)	(115)
Net income attributable to controlling interests	**1,840**	1,786	1,354	1,581	1,278
Preferred share dividends	**(97)**	(74)	(55)	(55)	(45)
Net income attributable to common shares	**1,743**	1,712	1,299	1,526	1,233
Comparable earnings	**1,715**	1,584	1,330	1,559	1,357
Comparable EBITDA	**5,521**	4,859	4,245	4,544	3,686
Cash Flow Statement					
Funds generated from operations	**4,268**	4,000	3,284	3,451	3,161
(Increase)/Decrease in operating working capital	**(189)**	(326)	287	235	(285)
Net cash provided by operations	**4,079**	3,674	3,571	3,686	2,876
Capital expenditures	**3,550**	4,264	2,595	2,513	4,376
Capital projects under development	**807**	488	3	16	—
Acquisitions, net of cash acquired	**241**	216	214	—	—
Cash dividends paid on common and preferred shares	**1,439**	1,356	1,281	1,016	754
Balance Sheet					
Assets					
Plant, property and equipment	**41,774**	37,606	33,713	32,467	30,987
Total assets	**58,947**	53,898	48,396	47,338	45,249
Capitalization					
Long-term debt	**24,757**	22,865	18,913	18,659	18,016
Junior subordinated notes	**1,160**	1,063	994	1,016	993
Preferred shares	**2,255**	1,813	1,224	1,224	1,224
Common shareholders' equity	**16,815**	16,712	15,687	15,570	15,133

	2014	2013	2012	2011	2010
Per Common Share Data					
Net income – basic	**$2.46**	$2.42	$1.84	$2.17	$1.79
– diluted	**$2.46**	$2.42	$1.84	$2.17	$1.78
Comparable earnings per share	**$2.42**	$2.24	$1.89	$2.22	$1.96
Dividends declared	**$1.92**	$1.84	$1.76	$1.68	$1.60
Book Value[1,2]	**$23.73**	$23.62	$22.24	$22.12	$21.74
Market Price					
Toronto Stock Exchange ($Cdn)					
High	**63.86**	51.21	47.44	44.74	39.28
Low	**47.14**	43.94	40.34	36.10	30.01
Close	**57.10**	48.54	47.02	44.53	37.99
Volume (millions of shares)	**337.20**	295.90	319.20	420.80	382.60
New York Stock Exchange ($US)					
High	**58.40**	49.65	47.78	45.09	38.59
Low	**42.21**	42.39	39.74	36.12	25.80
Close	**49.10**	45.66	47.32	43.67	38.04
Volume (millions of shares)	**249.00**	129.70	109.00	154.20	84.94
Common shares outstanding (millions)					
Average for the year	**708.0**	706.7	704.6	701.6	690.5
End of year	**708.7**	707.4	705.5	703.9	696.2
Registered common shareholders[1]	**30,513**	31,300	31,449	32,113	32,639
Per Preferred Share Data (dollars)					
Dividends declared:					
Series 1, 3, 5, 7 and 9 cumulative first preferred shares[3]	**$5.34**	$4.16	$3.25	$3.25	$2.60
Financial Ratios					
Dividend yield[4,5]	**3.4%**	3.8%	3.7%	3.8%	4.2%
Price/earnings multiple[5,6]	**23.2**	20.1	25.5	20.5	21.2
Price/book multiple[2,5]	**2.4**	2.1	2.1	2.0	1.7
Debt to debt plus shareholders' equity[7]	**61%**	59%	56%	56%	56%
Total shareholder return[8]	**22.0%**	7.2%	9.9%	22.2%	9.7%
Earnings to fixed charges[9]	**2.8**	2.8	2.2	2.6	1.9

1 As at December 31.

2 The price/book multiple is determined by dividing price per common share by book value per common share as calculated by dividing common shareholders' equity by the number of common shares outstanding as at December 31.

3 Preferred shares were issued for Series 1, 3, 5, 7 and 9 in September 2009, March 2010, June 2010, March 2013 and January 2014, respectively, with annual dividend rates of $1.15, $1.00, $1.10, $1.00 and $1.09 per share, respectively. The first quarterly dividends for each series were paid in December 2009, June 2010, November 2010, April 2013 and January 2014, respectively.

4 The dividend yield is determined by dividing dividends per common share declared during the year by price per common share as at December 31.

5 Price per common share refers to market price per share as reported on the Toronto Stock Exchange as at December 31.

6 The price/earnings multiple is determined by dividing price per common share by the basic net income per share.

7 Debt includes Junior Subordinated Notes, total long-term debt, including the current portion of long-term debt, plus preferred securities as at December 31 and excludes long-term debt of joint ventures. Shareholders' equity in this ratio is as at December 31.

8 Total shareholder return is the sum of the change in price per common share plus the dividends received plus the impact of dividend re-investment in a calendar year, expressed as a percentage of the value of shares at the end of the previous year.

9 The earnings to fixed charges ratio is determined by dividing earnings by fixed charges. Earnings is calculated as the sum of EBIT and interest income and other, less income attributable to non-controlling interests with interest expense and undistributed earnings of investments accounted for by the equity method. Fixed charges is calculated as the sum of interest expense, and capitalized interest.

Investor information

STOCK EXCHANGES, SECURITIES AND SYMBOLS

TransCanada Corporation
Common shares are listed on the Toronto and New York stock exchanges under the symbol: TRP

First Preferred Shares, Series 1 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.A

First Preferred Shares, Series 2 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.F

First Preferred Shares, Series 3 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.B

First Preferred Shares, Series 5 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.C

First Preferred Shares, Series 7 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.D

First Preferred Shares, Series 9 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.E

Annual Meeting The annual and special meeting of shareholders is scheduled for May 1, 2015 at 10:00 a.m. (Mountain Daylight Time) at the BMO Centre, Calgary, Alberta.

Dividend Payment Dates Scheduled common share dividend payment dates in 2015 are January 30, April 30, July 31 and October 30.

For information on dividend payment dates for TransCanada Corporation visit our website at www.transcanada.com.

Dividend Reinvestment and Share Purchase Plan TransCanada's dividend reinvestment and share purchase plan (Plan) allows common and preferred shareholders of TransCanada to purchase common shares of TransCanada by reinvesting their cash dividends without incurring brokerage or administrative fees. Participants in the Plan may also buy additional common shares, up to Cdn$10,000 per quarter. For more information on the Plan please contact our Plan agent, Computershare Trust Company of Canada or visit our website at www.transcanada.com.

TRANSFER AGENTS, REGISTRARS AND TRUSTEES

TransCanada Corporation Common Shares Computershare Trust Company of Canada (Montréal, Toronto, Calgary, Halifax and Vancouver) and Computershare Trust Company, N.A. (Golden)

TransCanada Corporation First Preferred Shares, Series 1 Computershare Trust Company of Canada (Montréal, Toronto, Calgary, Halifax and Vancouver)

TransCanada Corporation First Preferred Shares, Series 2 Computershare Trust Company of Canada (Montréal, Toronto, Calgary, Halifax and Vancouver)

TransCanada Corporation First Preferred Shares, Series 3 Computershare Trust Company of Canada (Montréal, Toronto, Calgary, Halifax and Vancouver)

TransCanada Corporation First Preferred Shares, Series 5 Computershare Trust Company of Canada (Montréal, Toronto, Calgary, Halifax and Vancouver)

TransCanada Corporation First Preferred Shares, Series 7 Computershare Trust Company of Canada (Montréal, Toronto, Calgary, Halifax and Vancouver)

TransCanada Corporation First Preferred Shares, Series 9 Computershare Trust Company of Canada (Montréal, Toronto, Calgary, Halifax and Vancouver)

TCPL Debentures

Canadian Series: BNY Trust Company of Canada (Halifax, Montréal, Toronto, Calgary and Vancouver)

10.50% series P 11.90% series S 11.80% series U
9.80% series V 9.45% series W

U.S. Series: The Bank of New York (New York) 9.875%

TCPL Canadian Medium-Term Notes CIBC Mellon Trust Company (Halifax, Montréal, Toronto, Calgary and Vancouver)

TCPL U.S. Medium-Term Notes and Senior Notes The Bank of New York Mellon (New York)

TCPL U.S. Junior Subordinated Notes Computershare Trust Company, N.A.

NOVA Gas Transmission Ltd. (NGTL) Debentures

Canadian Series: BNY Trust Company of Canada (Halifax, Montréal, Toronto, Calgary and Vancouver)

12.20% series 20 12.20% series 21 9.90% series 23

U.S. Series: U.S. Bank Trust National Association (New York) 7.875%

NGTL Canadian Medium-Term Notes BNY Trust Company of Canada (Halifax, Montréal, Toronto, Calgary and Vancouver)

NGTL U.S. Medium-Term Notes U.S. Bank Trust National Association (New York)

REGULATORY FILINGS

Annual Information Form TransCanada's 2014 Annual information form, as filed with Canadian securities commissions and as filed under Form 40-F with the SEC, is available on our website at www.transcanada.com.

A printed copy may be obtained from:

Corporate Secretary, TransCanada Corporation, 450 1st Street SW, Calgary, Alberta, Canada T2P 5H1

Shareholder assistance

If you are a registered shareholder and have questions regarding your account, please contact our transfer agent in writing, by telephone or e-mail at:

Computershare Trust Company of Canada, 100 University Avenue, 8th Floor, Toronto, Ontario, Canada M5J 2Y1

Toll-free: 1.800.340.5024
Telephone: 1.514.982.7959

E-mail: transcanada@computershare.com

www.computershare.com

If you hold your shares in a brokerage account (beneficial shareholder), questions should be directed to your broker on all administrative matters.

If you would like to receive quarterly reports, please contact Computershare or visit our website at www.transcanada.com.

Electronic Proxy Voting and Delivery of Documents TransCanada is pleased to offer registered and beneficial shareholders the ability to receive their documents (annual report, management information circular, notice of meeting and view-only proxy form) and vote online.

In 2015, registered shareholders who opt to receive their documents electronically will have a tree planted on their behalf through eTree. For more information and to sign up online, registered shareholders can visit www.etree.ca/transcanada.

Shareholders also have the ability to choose whether to receive TransCanada's annual report by regular mail. Each year, shareholders are required to renew their option and will receive a notification for doing so. The annual report is available on the TransCanada website at www.transcanada.com at the same time that the report is mailed to shareholders.

Electronic delivery and the ability to opt out of receiving the annual report by mail, provides increased convenience to shareholders, benefits to the environment and reduced mailing and printing costs for the company.

TransCanada in the Community TransCanada's annual Corporate Responsibility Report is available at www.transcanada.com. If you would like to receive a copy of this report by mail, please contact:

Communications 450 1st Street SW, Calgary, Alberta T2P 5H1, 1.403.920.2000 or 1.800.661.3805 or Communications@transcanada.com

Visit our website at www.transcanada.com to access TransCanada's corporate and financial information, including quarterly reports, news releases, real-time conference call webcasts and investor presentations.

Si vous désirez vous procurer un exemplaire de ce rapport en français, veuillez consulter notre site Web ou vous adresser par écrit à TransCanada Corporation, bureau du secrétaire.

Board of directors

(as at December 31, 2014)

S. Barry Jackson[1,2]
Chairman
TransCanada Corporation
Calgary, Alberta

Russell K. Girling
President and CEO
TransCanada Corporation
Calgary, Alberta

Kevin E. Benson[1,3]
Corporate Director
Calgary, Alberta

Derek H. Burney, O.C.[4,7]
Senior Strategic Advisor
Norton Rose Fulbright
Ottawa, Ontario

The Hon. Paule Gauthier, P.C., O.C., O.Q., Q.C.[2,5]
Senior Partner
Stein Monast L.L.P.
Québec, Québec

Paula Rosput Reynolds[5,8]
President and CEO
PreferWest, LLC
Seattle, Washington

John Richels[2,5]
President and CEO
Devon Energy Corporation
Nichols Hills, OK

Mary Pat Salomone[4,5]
Corporate Director
Naples, FL

D. Michael G. Stewart[4,6]
Corporate Director
Calgary, Alberta

Siim A. Vanaselja[1,4]
Executive Vice-President and CFO BCE Inc.
Westmount, Québec

Richard E. Waugh[1,2]
Former President and CEO
Scotiabank
Toronto, Ontario

1 Member, Governance Committee

2 Member, Human Resources Committee

3 Chair, Audit Committee

4 Member, Audit Committee

5 Member, Health, Safety and Environment Committee

6 Chair, Health, Safety and Environment Committee

7 Chair, Governance Committee

8 Chair, Human Resources Committee

Corporate governance

Please refer to TransCanada's Notice of 2015 annual and special meeting of shareholders and Management information circular for the company's statement of corporate governance.

TransCanada's Corporate Governance Guidelines, Board charter, Committee charters, Chair and Chief Executive Officer terms of reference and Code of business ethics are available on our website at www.transcanada.com. Also available on our website is a summary of the significant ways in which TransCanada's corporate governance practices differ from those required to be followed by U.S. domestic companies under the New York Stock Exchange's listing standards.

Additional information relating to the company is filed with securities regulators in Canada on SEDAR (www.sedar.com) and in the United States on EDGAR (www.sec.gov). The documents referred to in this Annual report may be obtained free of charge by contacting TransCanada's Corporate Secretary at 450 1st Street SW, Calgary, Alberta, Canada T2P 5H1, or by telephoning 1.800.661.3805.

Ethics Help-Line The Audit Committee of the Board of Directors has established an anonymous and confidential toll-free telephone number for employees, contractors and others to call with respect to accounting irregularities and ethical violations. The Ethics Help-Line number is 1.888.920.2042.

Shareholder Information

TransCanada welcomes questions from shareholders and investors.
Please contact:
David Moneta, Vice-President,
Investor Relations 1.800.361.6522
(Canada and U.S. Mainland)

investor_relations@transcanada.com
www.transcanada.com

Listing Information

Common Shares (TSX, NYSE): TRP

Preferred Shares (TSX):

Series 1: TRP.PR.A
Series 2: TRP.PR.F
Series 3: TRP.PR.B
Series 5: TRP.PR.C
Series 7: TPR.PR.D
Series 9: TPR.PR.E

Transfer Agent

Computershare Investor Services
100 University Avenue, 8th Floor
Toronto, Ontario M5J 2Y1
Phone: +1 416 263 9200
Fax: +1 888 453 0330

Corporate Social Responsibility Report

Building a successful future means doing the right thing today.
View our CSR report: **www.csrreport.transcanada.com**

Corporate Head Office

TransCanada Corporation
450 - 1 Street SW
Calgary, Alberta, Canada
T2P 5H1

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visit our site for more information.
www.transcanada.com

Printed in Canada
March 2015

TransCanada
In business to deliver

Member of
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Sustainability Indices
In Collaboration with RobecoSAM

CDP

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Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of TransCanada Corporation

We consent to the use of our reports, each dated February 12, 2015, with respect to the consolidated financial statements and the effectiveness of internal control over financial reporting included in this annual report on Form 40-F.

We also consent to the incorporation by reference of such reports in TransCanada Corporation's:

— Registration Statements No. 333-5916, No. 333-8470, No. 333-9130, No. 333-184074 and No. 333-151736 of Form S-8;

— Registration Statements No. 33-13564 and No. 333-6132 on Form F-3; and,

— Registration Statements No. 333-151781, No. 333-161929 and No. 333-192561 on Form F-10.

/s/ KPMG LLP
Chartered Accountants
Calgary, Canada

February 13, 2015

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Exhibit 23.1

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Exhibit 31.1

Certifications

I, Russell K. Girling, certify that:

1. I have reviewed this annual report on Form 40-F of TransCanada Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated February 13, 2015

/s/ RUSSELL K. GIRLING

Russell K. Girling
President and Chief Executive Officer

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Certifications

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Exhibit 31.2

Certifications

I, Donald R. Marchand, certify that:

1. I have reviewed this annual report on Form 40-F of TransCanada Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated February 13, 2015

/s/ DONALD R. MARCHAND

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

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Certifications

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Exhibit 32.1

TRANSCANADA CORPORATION

450 – 1st Street S.W.
Calgary, Alberta, Canada
T2P 5H1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
UNDER SECTION 906 OF SARBANES-OXLEY ACT OF 2002

I, Russell K. Girling, the Chief Executive Officer of TransCanada Corporation (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify, in connection with the Company's annual report as filed on Form 40-F for the fiscal year ending December 31, 2014 with the Securities and Exchange Commission (the "Report"), that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ RUSSELL K. GIRLING

Russell K. Girling
Chief Executive Officer
February 13, 2015

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TRANSCANADA CORPORATION
CERTIFICATION OF CHIEF EXECUTIVE OFFICER UNDER SECTION 906 OF SARBANES-OXLEY ACT OF 2002

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TRANSCANADA CORPORATION

450 – 1st Street S.W.
Calgary, Alberta, Canada
T2P 5H1

CERTIFICATION OF CHIEF FINANCIAL OFFICER
UNDER SECTION 906 OF SARBANES-OXLEY ACT OF 2002

I, Donald R. Marchand, the Chief Financial Officer of TransCanada Corporation (the "Company"), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, hereby certify, in connection with the Company's annual report as filed on Form 40-F for the fiscal year ending December 31, 2014 with the Securities and Exchange Commission (the "Report"), that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ DONALD R. MARCHAND

Donald R. Marchand
Chief Financial Officer
February 13, 2015

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Exhibit 32.2

TRANSCANADA CORPORATION
CERTIFICATION OF CHIEF FINANCIAL OFFICER UNDER SECTION 906 OF SARBANES-OXLEY ACT OF 2002