TRANSCANADA PIPELINES LTD
Form 40-F
February 13, 2015

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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 **1-8887**

TRANSCANADA PIPELINES LIMITED

(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: **None**

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: **Debt Securities**

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

o 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, 779,605,870 common shares,
which are all owned by TransCanada Corporation, 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 document (or portions thereof) forming part of this Form 40-F are incorporated by reference into the following registration statement under the Securities Act of 1933, as amended:

Form	Registration No.
F-10	333-192562

EXPLANATORY NOTE

An amendment to this Form 40-F shall be filed to include the TransCanada PipeLines Limited ("TCPL") Annual information form for the year ended December 31, 2014. The amendment shall be filed no later than the date the Annual information form is required pursuant to home country requirements.

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 TCPL 2014 Management's discussion and analysis and audited consolidated financial statements 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 97 through 156 of the TCPL 2014 Management's discussion and analysis and audited consolidated financial statements included herein.

B. Management's Discussion and Analysis

For management's discussion and analysis, see pages 1 through 96 of the TCPL 2014 Management's discussion and analysis and audited consolidated financial statements included herein.

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 97 of the TCPL 2014 Management's discussion and analysis and audited consolidated financial statements 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 81 and 82 of the TCPL 2014 Management's discussion and analysis and audited consolidated financial statements.

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

Pre-Approval Policies and Procedures

TCPL'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, non-audit services have been pre-approved by the Audit committee in accordance with the pre-approval policy described above.

External Auditor Service Fees

The following table provides information about the fees paid by the Company to KPMG LLP, the external auditor of the TransCanada group of companies, for professional services rendered for the 2014 and 2013 fiscal years.

($ millions)	**2014**	2013
Audit fees	**$6.4**	$6.4
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		
Audit-related fees	**0.2**	0.2
services related to the audit of the financial statements of certain TransCanada post-retirement and post-employment plans		
Tax fees	**0.5**	0.7
Canadian and international tax planning and tax compliance matters, including the review of income tax returns and other tax filings		
All other fees		
Total fees	**$7.1**	**$7.3**

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 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 70 of the TCPL 2014 Management's discussion and analysis and audited consolidated financial statements.

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 PIPELINES LIMITED

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	Management's discussion and analysis (included on pages 1 through 96 of the TCPL 2014 Management's discussion and analysis and audited consolidated financial statements).
13.2	2014 Audited consolidated financial statements (included on pages 97 through 156 of the TCPL 2014 Management's discussion and analysis and audited consolidated financial statements), including the auditors' report thereon.
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.

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 PipeLines Limited. 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).

Contents

About this document

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

Abbreviations and acronyms that are not defined in the document are defined in the glossary on page 96.

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

You can find more information about TCPL 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 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 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, TCPL 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. We are a wholly owned subsidiary of TransCanada Corporation (TransCanada).

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.

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	**4,422**	4,461
	61,838	56,626

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 1		
Natural Gas Pipelines	**2,187**	1,881
Liquids Pipelines	**843**	603
Energy	**1,051**	1,113
Corporate	**(150)**	(124)
	3,931	3,473

Common shares outstanding average (millions)	
2014	775
2013	749
2012	738

as at February 9, 2015 **Common shares**	**Issued and outstanding**
	779 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 3 for more information about the non-GAAP measures we use and page 89 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	**1,841**	1,769	1,338
per common share basic & diluted	**$2.38**	$2.36	$1.81
Comparable EBITDA	**5,521**	4,859	4,245
Comparable earnings	**1,813**	1,641	1,369
Operating cash flow			
Funds generated from operations	**4,267**	3,977	3,259
(Increase)/decrease in working capital	**(189)**	(334)	287
Net cash provided by operations	**4,078**	3,643	3,546
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	**61,838**	56,626	51,302
Long-term debt	**24,757**	22,865	18,913
Junior subordinated notes	**1,160**	1,063	994
Preferred shares	**-**	194	389
Non-controlling interests	**1,583**	1,417	1,036
Common shareholders' equity	**21,095**	19,827	17,915

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	**(1,235)**	(1,046)	(1,037)
Interest income and other	**128**	72	125
Income before income taxes	**2,824**	2,499	1,917
Income tax expense	**(830)**	(605)	(461)
Net income	**1,994**	1,894	1,456
Net income attributable to non-controlling interests	**(151)**	(105)	(96)
Net income attributable to controlling interests	**1,843**	1,789	1,360
Preferred share dividends	**(2)**	(20)	(22)
Net income attributable to common shares	**1,841**	1,769	1,338
Net income per common share basic and diluted	**$2.38**	$2.36	$1.81

Net income attributable to common shares

Net income attributable to common shares in 2014 was $1,841 million (2013 $1,769 million; 2012 $1,338 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 $)	**2014**	**2013**	**2012**
Net income attributable to common shares	**1,841**	1,769	1,338
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	**1,813**	1,641	1,369

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 $172 million higher than in 2013.

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, lower capitalized interest due to projects placed in service and lower interest expense on amounts due to TransCanada.
- 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.
- lower dividends due to redemption of Series Y Preferred Shares in March 2014.

Comparable earnings in 2013 were $272 million higher than 2012.

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 12 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 $10.5 billion since 2012. At December 31, 2014, common equity represented 47 per cent (47 per cent in 2013) of our capital structure. See page 66 for more information about our capital structure.

Quarterly dividend on our common shares

The dividend declared for the quarter ending March 31, 2015 is equal to the quarterly dividend to be paid on TransCanada's issued and outstanding common shares at the close of business on March 31, 2015.

Annual dividends on our preferred shares

In March 2014, TCPL redeemed all of the 4 million outstanding Series Y preferred shares at a redemption price of $50 per share plus $0.2455 representing accrued and unpaid dividends to such redemption date. As of December 31, 2014, we do not have any issued and outstanding preferred shares.

Cash dividends

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Common shares	**1,345**	1,285	1,226
Preferred shares	**4**	22	22

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.

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	28.3%

			TC PipeLines, LP	
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	100%

			Transmission project	
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
	(17)	(35)	(29)

Business Development comparable EBITDA and comparable EBIT

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 30 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 81 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 75 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.

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 81 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 75 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

1 Includes facilities under construction

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.

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 $)	**2014**	**2013**	**2012**
Canadian Power			
Western Power	**252**	355	311
Eastern Power[1]	**350**	322	321
Bruce Power	**314**	310	14
Canadian Power comparable EBITDA[1]	**916**	987	646
Comparable depreciation and amortization	**(179)**	(172)	(152)
Canadian Power comparable EBIT[1]	**737**	815	494
U.S. Power (US$)			
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[1]	**32**	51	57
Business Development comparable EBITDA and EBIT	**(26)**	(20)	(19)
Energy comparable EBIT[1]	**1,039**	1,069	620
Summary			
Energy comparable EBITDA[1]	**1,348**	1,363	903
Comparable depreciation and amortization	**(309)**	(294)	(283)
Energy comparable EBIT[1]	**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 81 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 3 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 3 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-Québe