Management's discussion and analysis

February 14, 2018

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TransCanada Corporation. It discusses our business, operations, financial position, risks and other factors for the year ended December 31, 2017.

This MD&A should be read with our accompanying December 31, 2017 audited 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 ***TransCanada*** mean TransCanada Corporation and its subsidiaries. Abbreviations and acronyms that are not defined in the document are defined in the glossary on page 108. All information is as of February 14, 2018 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 include information about the following, among other things:

- planned changes in our business
- 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 dividend growth
- expected costs for planned projects, including projects under construction, permitting and in development
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes
- expected outcomes with respect to legal proceedings, including arbitration 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
- the expected impact of U.S. Tax Reform
- 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

- planned wind-down of our U.S. Northeast power marketing business
- inflation rates and commodity prices
- nature and scope of hedging
- regulatory decisions and outcomes
- interest, tax and foreign exchange rates, including the impact of U.S. Tax Reform
- 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.

Risks and uncertainties

- our ability to successfully implement our strategic priorities and whether they will yield the expected benefits
- the operating performance of our pipeline and energy assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the availability and price of energy commodities
- the amount of capacity payments and revenues from our energy business
- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration and insurance claims
- performance and credit risk 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, tax and foreign exchange rates, including the impact of U.S. Tax Reform
- 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 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 also find more information about TransCanada in our Annual Information Form and other disclosure documents, which are available on SEDAR (www.sedar.com).

NON-GAAP MEASURES

This MD&A references the following non-GAAP measures:

- comparable earnings
- comparable earnings per common share
- comparable EBITDA
- comparable EBIT
- funds generated from operations
- comparable funds generated from operations
- comparable distributable cash flow
- comparable distributable cash flow per common share.

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

Comparable measures

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

Our decision not to adjust for 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 and changes to enacted tax rates
- gains or losses on sales of assets or assets held for sale
- legal, contractual and bankruptcy settlements
- impact of regulatory or arbitration decisions relating to prior year earnings
- restructuring costs
- impairment of goodwill, investments and other assets including certain ongoing maintenance and liquidation costs
- acquisition and integration costs.

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

The following table identifies our non-GAAP measures and their equivalent GAAP measures.

Comparable measure	Original measure
comparable earnings	net income/(loss) attributable to common shares
comparable earnings per common share	net income/(loss) per common share
comparable EBITDA	segmented earnings
comparable EBIT	segmented earnings
comparable funds generated from operations	net cash provided by operations
comparable distributable cash flow	net cash provided by operations

Comparable earnings and comparable earnings per share

Comparable earnings represents earnings or loss attributable to common shareholders on a consolidated basis adjusted for specific items. Comparable earnings is comprised of segmented earnings, interest expense, AFUDC, interest income and other, income taxes and non-controlling interests adjusted for the specific items. See the Financial highlights section for a reconciliation of net income/(loss) attributable to common shares and net income/(loss) per common share.

Comparable EBIT and comparable EBITDA

Comparable EBIT represents segmented earnings adjusted for the specific items described above. We use comparable EBIT as a measure of our earnings from ongoing operations as it is a useful measure of our performance and an effective tool for evaluating trends in each segment. Comparable EBITDA is calculated the same way as comparable EBIT but excludes the non-cash charges for depreciation and amortization. See the Other information section for a reconciliation to segmented earnings.

Funds generated from operations and comparable funds generated from operations

Funds generated from operations reflects 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. Comparable funds generated from operations is adjusted for the cash impact of specific items noted above. See the Financial condition section for a reconciliation to net cash provided by operations.

Comparable distributable cash flow and comparable distributable cash flow per share

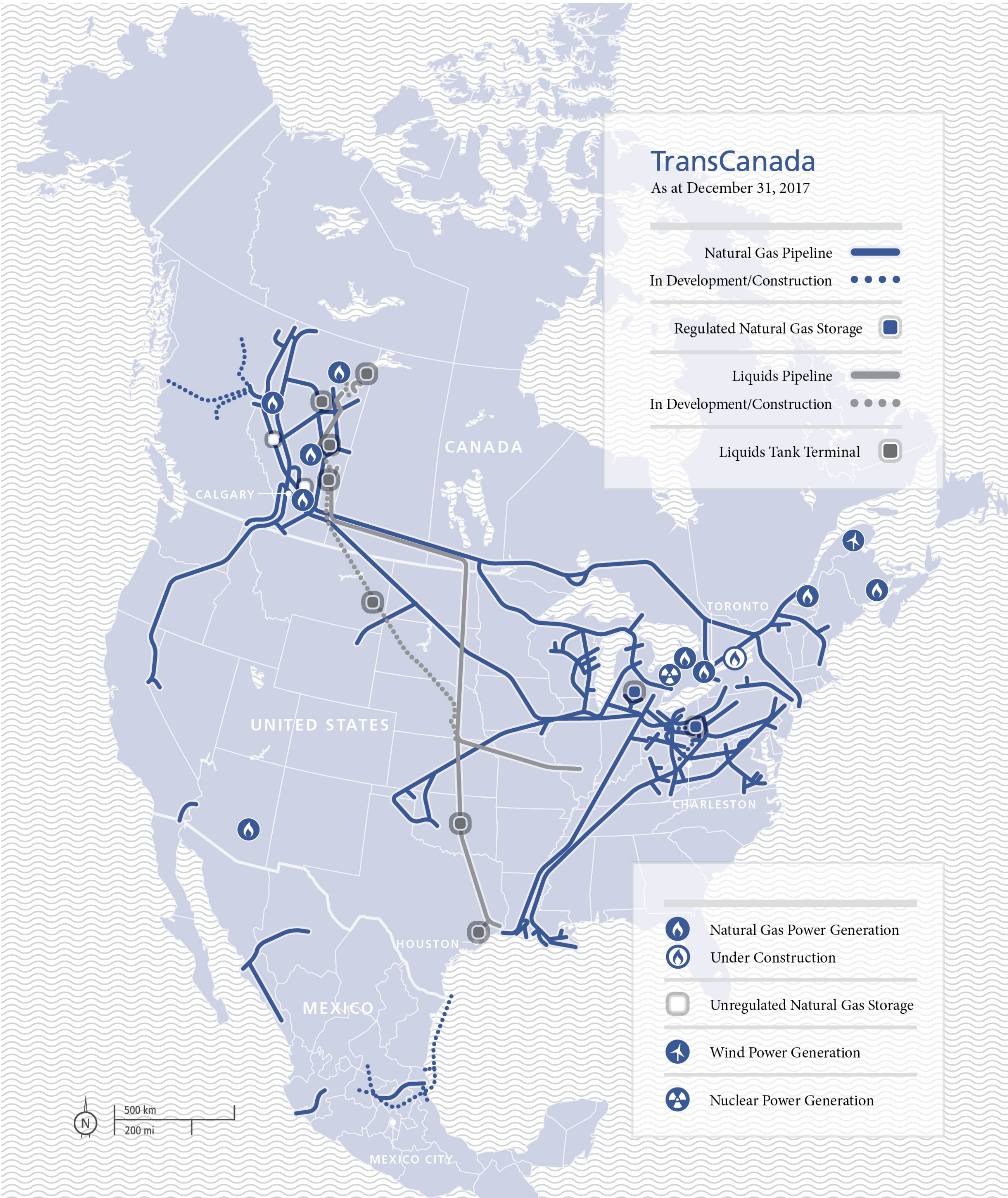
We believe comparable distributable cash flow is a useful supplemental measure of performance that defines cash available to common shareholders before capital allocation. Comparable distributable cash flow is defined as comparable funds generated from operations less preferred share dividends, distributions to non-controlling interests and maintenance capital expenditures. Maintenance capital expenditures are expenditures incurred to maintain our operating capacity, asset integrity and reliability, and include amounts attributable to our proportionate share of maintenance capital expenditures on our equity investments. See the Financial condition section for a reconciliation to net cash provided by operations.

Although we deduct maintenance capital expenditures in determining comparable distributable cash flow, we have the ability to recover the majority of these costs in Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Liquids Pipelines. Canadian natural gas pipelines maintenance capital expenditures are reflected in rate bases, on which we earn a regulated return and subsequently recover in tolls. The majority of our U.S. natural gas pipelines can seek to recover maintenance capital expenditures through rates established in future rate cases or rate settlements. As such, these maintenance capital expenditures are effectively recovered in the same manner as expansion capital expenditures. Tolling arrangements in Liquids Pipelines provide for recovery of maintenance capital.

Effective December 31, 2017, we amended our presentation of comparable distributable cash flow and comparable distributable cash flow per share to illustrate the impact of excluding recoverable maintenance capital expenditures from their respective calculations. We have included comparable distributable cash flow and comparative distributable cash flow per share for 2016 and 2015 to reflect the amended presentation format which we believe provides better information for readers.

About our business

With over 65 years of experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and liquids pipelines, power generation and natural gas storage facilities.



THREE CORE BUSINESSES

We operate in three core businesses – Natural Gas Pipelines, Liquids Pipelines and Energy. In order to provide information that is aligned with how management decisions about our business are made and how performance of our business is assessed, our results are reflected in five operating segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines and Energy. We also have a non-operational Corporate segment consisting of corporate and administrative functions that provide governance and other support to our operational business segments.

Year at a glance

at December 31 (millions of $)	2017	2016
Total assets		
Canadian Natural Gas Pipelines	**16,904**	15,816
U.S. Natural Gas Pipelines	**35,898**	34,422
Mexico Natural Gas Pipelines	**5,716**	5,013
Liquids Pipelines	**15,438**	16,896
Energy[1]	**8,503**	13,169
Corporate	**3,642**	2,735
	86,101	88,051

1 2016 includes U.S. Northeast power assets held for sale.

year ended December 31 (millions of $)	2017	2016
Total revenues		
Canadian Natural Gas Pipelines	**3,693**	3,682
U.S. Natural Gas Pipelines[1]	**3,584**	2,526
Mexico Natural Gas Pipelines	**570**	378
Liquids Pipelines	**2,009**	1,755
Energy[2]	**3,593**	4,206
	13,449	12,547

1 Includes Columbia effective July 2016.

2 Includes U.S. Northeast power and Ontario solar assets until sold in 2017.

year ended December 31 (millions of $)	2017	2016
Comparable EBITDA		
Canadian Natural Gas Pipelines	**2,144**	2,182
U.S. Natural Gas Pipelines[1]	**2,357**	1,682
Mexico Natural Gas Pipelines	**519**	332
Liquids Pipelines	**1,348**	1,152
Energy[2]	**1,030**	1,281
Corporate	**(21)**	18
	7,377	6,647

1 Includes Columbia effective July 2016.

2 Includes U.S. Northeast power and Ontario solar assets until sold in 2017.

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 at a glance

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

- 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 flow and earnings.
- In Energy, long-term power sale agreements are used to manage and optimize our portfolio and to manage price volatility.

2 Commercially develop and build new asset investment programs

- We are developing high quality, long-life assets under our current $47 billion capital program, comprised of $23 billion in near-term projects and $24 billion in commercially-supported medium to long-term projects. These will contribute incremental earnings and cash flow over the near, medium and long terms as our investments are placed in service.
- Our expertise in project development, managing construction risks and maximizing capital productivity ensures a disciplined approach to reliability, 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 pipeline and other energy facilities.
- We are able to balance safety, profitability and social and environmental responsibility in our investing activities.

3 Cultivate a focused portfolio of high quality development and investment options

- We assess opportunities to develop and acquire energy infrastructure that complements our existing portfolio and diversifies access to attractive supply and market regions.
- We focus on pipeline and energy growth initiatives in core regions of North America and prudently manage development costs, minimizing capital-at-risk in early stages of projects.
- 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

- We are continually refining core competencies in areas such as safety, operational excellence, supply chain management, project execution and stakeholder management 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 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 and enduring business model that maximizes the full-life value of our long-life assets and commercial positions throughout all points in the business cycle.
- Disciplined operations: highly skilled in designing, building and operating energy infrastructure with a focus on operational excellence and a commitment to health, safety and the environment which are paramount parts of our core values.
- Financial positioning: consistently strong financial performance, long-term financial stability and profitability; disciplined approach to capital investment; ability to access sizable amounts of competitively priced capital to support our growth; simplicity and understandability of our business and corporate structure; ability to balance an increasing dividend on our common shares while preserving financial flexibility to fund our capital program in all market conditions.
- Long-term relationships: long-term, transparent relationships with key customers and stakeholders; clear communication of our prospects to equity and fixed income investors – both the upside and the risks – to build trust and support.

U.S. TAX REFORM

On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act (U.S. Tax Reform or the Act) was signed, resulting in significant changes to U.S. tax law, including a decrease in the U.S. federal corporate income tax rate from 35 per cent to 21 per cent effective January 1, 2018. As a result of this change, we have remeasured existing deferred income tax assets and deferred income tax liabilities related to our U.S. businesses to reflect the new lower income tax rate as at December 31, 2017.

For our businesses in the U.S. not subject to rate-regulated accounting (RRA), the reduction in enacted tax rates has been recorded as a decrease in net deferred income tax liabilities and income tax expense, resulting in an increase in net income attributable to common shares for the year ended December 31, 2017 in the amount of $816 million.

For our businesses in the U.S. subject to RRA, we expect the lower income tax rates to impact future rate setting processes and have therefore recognized a net regulatory liability with a corresponding reduction in net deferred income tax liabilities in the amount of $1,686 million. These regulatory liabilities will be amortized to earnings over time.

Net deferred income tax liabilities related to the cumulative remeasurements of employee post-retirement benefits included in accumulated other comprehensive income have also been adjusted with a corresponding increase in deferred income tax expense of $12 million.

Given the significance of the legislation, the SEC issued guidance which allows registrants to record provisional amounts which may be adjusted as information becomes available, prepared or analyzed during a measurement period not to exceed one year.

The SEC guidance summarizes a three-step process to be applied at each reporting period to identify: (1) where the accounting is complete; (2) provisional amounts where the accounting is not yet complete, but a reasonable estimate has been determined; and (3) where a reasonable estimate cannot yet be determined and therefore income taxes are reflected in accordance with tax laws in effect prior to the enactment of the Act.

At December 31, 2017, we consider all amounts recorded related to U.S. Tax Reform to be reasonable estimates. Amounts related to businesses subject to RRA are provisional as our interpretation, assessment and presentation of the impact of the tax law change may be further clarified with additional guidance from regulatory, tax and accounting authorities. Should additional guidance be provided by these authorities or other sources during the one-year measurement period, we will review the provisional amounts and adjust as appropriate.

As a result of the lower U.S. income tax rates included as part of the Act, we expect a modest increase to 2018 earnings. In addition to the reduction in statutory rates, longer-term there are several other provisions in the new legislation which may impact us prospectively, including changes to the expensing of depreciable property, limitations to interest deductions, the creation of Base Erosion Anti-Abuse Tax along with certain exemptions for rate-regulated businesses. We continue to evaluate the impact of these and other provisions of the Act.

2016 ACQUISITION OF COLUMBIA PIPELINE GROUP, INC.

On July 1, 2016, we acquired 100 per cent ownership of Columbia for a purchase price of US$10.3 billion in cash. The acquisition was initially financed through proceeds of $4.4 billion from the sale of subscription receipts, draws on acquisition bridge facilities in the aggregate amount of US$6.9 billion and existing cash on hand. The sale of the subscription receipts was completed on April 1, 2016 through a public offering and, following the closing of the acquisition, were exchanged into 96.6 million TransCanada common shares.

At the date of acquisition, Columbia operated approximately 24,500 km (15,200 miles) of regulated natural gas pipelines, 285 Bcf of natural gas storage facilities and related midstream assets. We acquired Columbia to expand our natural gas business in the U.S. market, positioning ourselves for additional long-term growth opportunities. The acquisition also included a large portfolio of new capital growth projects including seven significant pipeline expansions designed to transport growing supply from the Marcellus/ Utica production basins to markets, as well as a scheduled program for modernization of existing infrastructure through 2020 to ensure the continuation of a safe, reliable and efficient system.

While Columbia Pipeline Group, Inc. was the overall corporate entity we acquired, we now make reference to specific businesses obtained through the acquisition including: Columbia Gas, Columbia Gulf, Millennium, Crossroads, Midstream and Columbia Storage.

As part of the financing plan for the Columbia acquisition, we announced the planned monetization of our U.S. Northeast power business, including our U.S. Northeast power marketing business. Subsequently, we issued additional common shares to support the permanent financing of the acquisition and announced an agreement to acquire all of the outstanding publicly held common units of Columbia Pipeline Partners LP (CPPL).

Common shares and subscription receipts issued under public offerings

On April 1, 2016, we issued 96.6 million subscription receipts entitling each holder to receive one common share upon closing of the Columbia acquisition to partially fund the Columbia acquisition at a price of $45.75 each for gross proceeds of $4.4 billion. Holders of subscription receipts received one common share in exchange for each subscription receipt on July 1, 2016 upon closing of the acquisition.

On November 16, 2016, we issued 60.2 million common shares at a price of $58.50 each for gross proceeds of approximately $3.5 billion. Proceeds from the offering were used to repay a portion of the US$6.9 billion acquisition bridge facilities which were drawn to partially finance the closing of the Columbia acquisition.

Columbia Pipeline Partners LP

In February 2017, we completed the acquisition, for cash, of all outstanding publicly held common units of CPPL for an aggregate transaction value of US$921 million. See the U.S. Natural Gas Pipelines Significant events section for further information.

Monetization of U.S. Northeast power business

In April 2017, we closed the sale of TC Hydro for US$1.07 billion, before post-closing adjustments, and in June 2017, we closed the sale of Ravenswood, Ironwood, Ocean State Power and Kibby Wind for US$2.029 billion, before post-closing adjustments. Proceeds from these sales were used to fully retire the remaining bridge facilities that partially funded the acquisition of Columbia.

In December 2017, we entered into an agreement to sell our U.S. power retail contracts as part of the continued wind down of our U.S. power marketing operations. The transaction is expected to close in the first quarter of 2018 subject to regulatory and other approvals.

See the Energy Significant events section for further information.

CAPITAL PROGRAM

We are developing quality projects under our 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 approximately $23 billion of near-term projects and approximately $24 billion of commercially supported medium to longer-term projects. Amounts presented exclude maintenance capital expenditures, capitalized interest and AFUDC.

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

Near-term projects

(billions of $)	Expected in-service date	Estimated project cost	Carrying value at December 31, 2017
Canadian Natural Gas Pipelines			
Canadian Mainline	2018 - 2021	0.2	—
NGTL System	2018	0.6	0.2
	2019	2.3	0.3
	2020	1.6	0.1
	2021	2.7	—
U.S. Natural Gas Pipelines			
Columbia Gas			
Leach XPress[1]	2018	US 1.6	US 1.5
WB XPress	2018	US 0.8	US 0.4
Mountaineer XPress	2018	US 2.6	US 0.5
Modernization II	2018 - 2020	US 1.1	US 0.1
Buckeye XPress	2020	US 0.2	—
Columbia Gulf			
Cameron Access	2018	US 0.3	US 0.3
Gulf XPress	2018	US 0.6	US 0.2
Other[2]	2018 - 2020	US 0.3	—
Mexico Natural Gas Pipelines			
Sur de Texas[3]	2018	US 1.3	US 1.0
Villa de Reyes	2018	US 0.8	US 0.5
Tula	2019	US 0.7	US 0.5
Liquids Pipelines			
White Spruce	2019	0.2	—
Energy			
Napanee	2018	1.3	0.9
Bruce Power – life extension[4]	up to 2020	0.9	0.3
		20.1	**6.8**
Foreign exchange impact on near-term projects[5]		**2.6**	**1.3**
Total near-term projects (billions of Cdn$)		**22.7**	**8.1**

1 Leach XPress was placed in service in January 2018.
2 Reflects our proportionate share of costs related to Portland Xpress and various expansion projects.
3 Our proportionate share.
4 Amount reflects our proportionate share of the remaining capital costs that Bruce Power expects to incur on its life extension investment programs in advance of the Unit 6 major refurbishment outage which is expected to begin in 2020.
5 Reflects U.S./Canada foreign exchange rate of 1.25 at December 31, 2017.

Medium to longer-term projects

The medium to longer-term projects have greater uncertainty with respect to timing and estimated project costs. The expected in-service dates of these projects are post-2020, and costs provided in the schedule below reflect the most recent costs for each project as filed with the applicable regulatory authorities or otherwise determined. These projects are subject to approvals that include FID and/or complex regulatory processes; however, each project has commercial support except where noted. Please refer to each business segment's Significant events section for further information on these projects.

(billions of $)	Segment	Estimated project cost	Carrying value at December 31, 2017
Heartland and TC Terminals[1]	Liquids Pipelines	0.9	0.1
Grand Rapids Phase 2[2]	Liquids Pipelines	0.7	—
Bruce Power – life extension[2]	Energy	5.3	—
Keystone projects			
Keystone XL[3]	Liquids Pipelines	US 8.0	US 0.3
Keystone Hardisty Terminal[1,3]	Liquids Pipelines	0.3	0.1
BC west coast LNG-related projects			
Coastal GasLink	Canadian Natural Gas Pipelines	4.8	0.4
NGTL System – Merrick	Canadian Natural Gas Pipelines	1.9	—
		21.9	**0.9**
Foreign exchange impact on medium to longer-term projects[4]		**2.0**	**0.1**
Total medium to longer-term projects (billions of Cdn$)		**23.9**	**1.0**

1 Regulatory approvals have been obtained; additional commercial support is being pursued.
2 Our proportionate share.
3 Carrying value reflects amount remaining after impairment charge recorded in 2015.
4 Reflects U.S./Canada foreign exchange rate of 1.25 at December 31, 2017.

2017 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.

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, comparable funds generated from operations, comparable distributable cash flow and comparable distributable cash flow per common share are all non-GAAP measures. See page 8 for more information about the non-GAAP measures we use and pages 72 and 100 for reconciliations to the GAAP equivalents.

year ended December 31 (millions of $, except per share amounts)	**2017**	**2016**	**2015**
Income			
Revenues	**13,449**	12,547	11,353
Net income/(loss) attributable to common shares	**2,997**	124	(1,240)
per common share – basic	**$3.44**	$0.16	($1.75)
– diluted	**$3.43**	$0.16	($1.75)
Comparable EBITDA	**7,377**	6,647	5,908
Comparable earnings	**2,690**	2,108	1,755
per common share	**$3.09**	$2.78	$2.48
Cash flows			
Net cash provided by operations	**5,230**	5,069	4,384
Comparable funds generated from operations	**5,641**	5,171	4,815
Comparable distributable cash flow			
– reflecting all maintenance capital expenditures	**3,599**	3,541	3,457
– reflecting only non-recoverable maintenance capital expenditures	**4,963**	4,482	4,243
Comparable distributable cash flow per common share			
– reflecting all maintenance capital expenditures	**$4.13**	$4.67	$4.88
– reflecting only non-recoverable maintenance capital expenditures	**$5.69**	$5.91	$5.98
Capital spending[1]	**9,210**	6,067	4,922
Acquisitions, net of cash acquired	**—**	13,608	236
Proceeds from sales of assets, net of transaction costs	**5,317**	6	—
Balance sheet			
Total assets	**86,101**	88,051	64,398
Long-term debt	**34,741**	40,150	31,456
Junior subordinated notes	**7,007**	3,931	2,409
Preferred shares	**3,980**	3,980	2,499
Non-controlling interests	**1,852**	1,726	1,717
Common shareholders' equity	**21,059**	20,277	13,939
Dividends declared[2]			
per common share	**$2.50**	$2.26	$2.08
Basic common shares (millions)			
– weighted average	**872**	759	709
– issued and outstanding	**881**	864	703

1 Includes capital expenditures, capital projects in development and contributions to equity investments.

2 See financial condition on page 78 for details on preferred share dividends.

Consolidated results

year ended December 31 (millions of $, except per share amounts)	2017	2016	2015
Segmented earnings/(losses)			
Canadian Natural Gas Pipelines	**1,236**	1,307	1,367
U.S. Natural Gas Pipelines	**1,760**	1,190	597
Mexico Natural Gas Pipelines	**426**	287	169
Liquids Pipelines	**(251)**	806	(2,661)
Energy	**1,552**	(1,157)	781
Corporate	**(39)**	(120)	(152)
Total segmented earnings	**4,684**	2,313	101
Interest expense	**(2,069)**	(1,998)	(1,370)
Allowance for funds used during construction	**507**	419	295
Interest income and other	**184**	103	(132)
Income/(loss) before income taxes	**3,306**	837	(1,106)
Income tax recovery/(expense)	**89**	(352)	(34)
Net income/(loss)	**3,395**	485	(1,140)
Net income attributable to non-controlling interests	**(238)**	(252)	(6)
Net income/(loss) attributable to controlling interests	**3,157**	233	(1,146)
Preferred share dividends	**(160)**	(109)	(94)
Net income/(loss) attributable to common shares	**2,997**	124	(1,240)
Net income/(loss) per common share			
–basic	**$3.44**	$0.16	($1.75)
–diluted	**$3.43**	$0.16	($1.75)

Net income attributable to common shares in 2017 was $2,997 million or $3.44 per share (2016 – $124 million or $0.16 per share; 2015 – loss of $1,240 million or $1.75 per share). Net income per common share increased by $3.28 per share in 2017 compared to 2016 due to the changes in net income described below, as well as the dilutive effect of issuing 161 million common shares in 2016 and common shares issued under our DRP and corporate ATM program in 2017.

The following specific items were recognized in net income/(loss) attributable to common shares and were excluded from comparable earnings in the relevant periods:

2017

- an $804 million recovery of deferred income taxes as a result of U.S. Tax Reform
- a $307 million after-tax net gain related to the monetization of our U.S. Northeast power business, which included a $440 million after-tax gain on the sale of TC Hydro, an incremental after-tax loss of $190 million recorded on the sale of the thermal and wind package, $23 million of after-tax third-party insurance proceeds related to a 2017 Ravenswood outage, $14 million of after-tax disposition costs, and income tax adjustments
- a $136 million after-tax gain related to the sale of our Ontario solar assets
- a $954 million after-tax impairment charge for the Energy East pipeline and related projects as a result of our decision not to proceed with the project applications
- a $69 million after-tax charge for integration-related costs associated with the acquisition of Columbia
- a $28 million after-tax charge related to the maintenance and liquidation of Keystone XL assets which were expensed pending further advancement of the project
- a $7 million income tax recovery related to the realized loss on a third party sale of Keystone XL project assets. A provision for the expected pre-tax loss on these assets was included in our 2015 impairment charge, but the related income tax recoveries could not be recorded until realized.

2016

- a $656 million after-tax impairment of Ravenswood goodwill. As a result of information received during the process to monetize our U.S. Northeast power business in third quarter 2016, it was determined that the fair value of Ravenswood no longer exceeded its carrying value
- an $873 million after-tax loss on U.S. Northeast power assets held for sale which included an $863 million after-tax loss on the thermal and wind package held for sale and $10 million of after-tax disposition costs
- a $176 million after-tax impairment charge on the carrying value of our Alberta PPAs (both directly and through our equity investment in ASTC Power Partnership) as a result of our decision to terminate the PPAs and a $68 million after-tax loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the PPA terminations
- costs associated with the acquisition of Columbia resulting in an after-tax charge of $273 million which included $109 million of dividend equivalent payments on the subscription receipts issued as part of the permanent financing of the transaction, $90 million of retention, severance and integration costs, $36 million of acquisition costs and a $44 million deferred income tax adjustment upon closing of the acquisition, partially offset by $6 million of interest earned on the subscription receipt funds held in escrow prior to their conversion to common shares
- $28 million of income tax recoveries related to the realized loss on a third party sale of Keystone XL project assets. A provision for the expected pre-tax loss on these assets was included in our fourth quarter 2015 impairment charge, but the related income tax recoveries could not be recorded until realized
- an after-tax charge of $42 million related to Keystone XL costs for the maintenance and liquidation of project assets which were expensed pending further advancement of the project
- an after-tax charge of $16 million for restructuring mainly related to expected future losses under lease commitments. These charges formed part of a restructuring initiative, which commenced in 2015, to maximize the effectiveness and efficiency of our existing operations and reduce overall costs
- an additional $3 million after-tax loss on the sale of TC Offshore which closed in early 2016.

2015

- a $2,891 million after-tax impairment charge on the carrying value of our investment in Keystone XL and related projects
- an $86 million after-tax loss provision related to the sale of TC Offshore which closed in early 2016
- a net charge of $74 million after tax for restructuring comprised of $42 million mainly related to 2015 severance costs and a provision of $32 million for 2016 planned severance costs and expected future losses under lease commitments. These charges formed part of a restructuring initiative, which commenced in 2015, to maximize the effectiveness and efficiency of our existing operations and reduce overall costs
- a $43 million after-tax charge relating to an impairment in value of turbine equipment held for future use in our Energy business
- a $34 million adjustment to income tax expense due to the enactment of a two per cent increase in the Alberta corporate income tax rate in June 2015
- a charge of $27 million after tax related to Bruce Power's retirement of debt in conjunction with the merger of the Bruce A and Bruce B partnerships
- a $199 million positive income adjustment related to the impact on our net income from non-controlling interests of TC PipeLines, LP's impairment of their equity investment in Great Lakes.

Net income in all periods included unrealized gains and losses from changes in risk management activities which we exclude, along with the above noted items, to arrive at comparable earnings. A reconciliation of net income/(loss) attributable to common shares to comparable earnings is shown in the following table.

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

Reconciliation of net income/(loss) to comparable earnings

year ended December 31 (millions of $, except per share amounts)	2017	2016	2015
Net income/(loss) attributable to common shares	**2,997**	124	(1,240)
Specific items (net of tax):			
U.S. Tax Reform adjustment	**(804)**	—	—
Net (gain)/loss on sales of U.S. Northeast power assets	**(307)**	873	—
Gain on sale of Ontario solar assets	**(136)**	—	—
Energy East impairment charge	**954**	—	—
Integration and acquisition related costs – Columbia	**69**	273	—
Keystone XL asset costs	**28**	42	—
Keystone XL income tax recoveries	**(7)**	(28)	—
Ravenswood goodwill impairment	**—**	656	—
Alberta PPA terminations and settlement	**—**	244	—
Restructuring costs	**—**	16	74
TC Offshore loss on sale	**—**	3	86
Keystone XL impairment charge	**—**	—	2,891
Turbine equipment impairment charge	**—**	—	43
Alberta corporate income tax rate increase	**—**	—	34
Bruce Power merger – debt retirement charge	**—**	—	27
Non-controlling interests (TC PipeLines, LP – Great Lakes impairment)	**—**	—	(199)
Risk management activities[1]	**(104)**	(95)	39
Comparable earnings	**2,690**	2,108	1,755
Net income/(loss) per common share	**$3.44**	$0.16	($1.75)
Specific items (net of tax):			
U.S. Tax Reform adjustment	**(0.92)**	—	—
Net (gain)/loss on sales of U.S. Northeast power assets	**(0.34)**	1.15	—
Gain on sale of Ontario solar assets	**(0.16)**	—	—
Energy East impairment charge	**1.09**	—	—
Integration and acquisition related costs – Columbia	**0.08**	0.37	—
Keystone XL asset costs	**0.03**	0.06	—
Keystone XL income tax recoveries	**(0.01)**	(0.04)	—
Ravenswood goodwill impairment	**—**	0.86	—
Alberta PPA terminations and settlement	**—**	0.32	—
Restructuring costs	**—**	0.02	0.10
TC Offshore loss on sale	**—**	—	0.12
Keystone XL impairment charge	**—**	—	4.08
Turbine equipment impairment charge	**—**	—	0.06
Alberta corporate income tax rate increase	**—**	—	0.05
Bruce Power merger – debt retirement charge	**—**	—	0.04
Non-controlling interests (TC PipeLines, LP – Great Lakes impairment)	**—**	—	(0.28)
Risk management activities	**(0.12)**	(0.12)	0.06
Comparable earnings per common share	**$3.09**	$2.78	$2.48

1

year ended December 31 (millions of $)	2017	2016	2015
Canadian Power	**11**	4	(8)
U.S. Power	**39**	113	(30)
Liquids marketing	**—**	(2)	—
Natural Gas Storage	**12**	8	1
Interest rate	**(1)**	—	—
Foreign exchange	**88**	26	(21)
Income taxes attributable to risk management activities	**(45)**	(54)	19
Total unrealized gains/(losses) from risk management activities	**104**	95	(39)

Comparable earnings

Comparable earnings per share in 2017 and 2016 were impacted by the dilutive effect of issuing 161 million common shares in 2016 and common shares issued under our DRP and corporate ATM program in 2017. See the Financial condition section of this MD&A for further information on common share issuances.

Comparable earnings in 2017 were $582 million higher than 2016, resulting in an increase of $0.31 per common share. The 2017 increase in comparable earnings was primarily the net result of:

- higher contribution from U.S. Natural Gas Pipelines due to incremental earnings from Columbia following the July 1, 2016 acquisition and higher ANR transportation revenue resulting from a FERC-approved rate settlement effective August 1, 2016
- increased earnings from Liquids Pipelines primarily due to higher uncontracted volumes on the Keystone Pipeline System, liquids marketing activities and the commencement of operations on Grand Rapids and Northern Courier
- higher earnings from Bruce Power mainly due to higher volumes resulting from fewer outage days
- higher contribution from Mexico Natural Gas Pipelines due to earnings from Topolobampo beginning in July 2016 and Mazatlán beginning in December 2016
- higher AFUDC on our rate-regulated U.S. natural gas pipelines, as well as the NGTL System, Tula and Villa de Reyes, partially offset by the commercial in-service of Topolobampo and completion of Mazatlán construction
- higher interest income and other due to income related to recovery of certain Coastal GasLink project costs and the termination of the PRGT project
- lower contribution from U.S. Power due to the monetization of our U.S. Northeast power generation assets in second quarter 2017 and the continued wind-down of our U.S. power marketing operations
- higher interest expense as a result of debt assumed in the acquisition of Columbia on July 1, 2016 and long-term debt and junior subordinated note issuances in 2017, net of maturities.

Comparable earnings in 2016 were $353 million higher than 2015, resulting in an increase of $0.30 per common share. The 2016 increase in comparable earnings was primarily the net result of:

- higher contribution from U.S. Natural Gas Pipelines primarily due to incremental earnings following the July 1, 2016 Columbia acquisition, higher ANR transportation revenues resulting from a FERC-approved rate settlement effective August 1, 2016, new contracts on ANR Southeast Mainline and lower OM&A expenses
- higher interest expense from debt issuances and lower capitalized interest
- higher interest income and other due to realized gains in 2016 compared to realized losses in 2015 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar denominated income
- lower earnings from Liquids Pipelines due to the net effect of higher contracted and lower uncontracted volumes on Keystone, as well as lower volumes on Marketlink
- higher AFUDC on our rate-regulated projects including those for the NGTL System, Energy East, Columbia and Mexico pipelines
- higher contribution from Mexico Natural Gas Pipelines primarily due to earnings from Topolobampo beginning in July 2016
- higher earnings from Natural Gas Storage due to higher realized natural gas storage price spreads.

Cash flows

Net cash provided by operations of $5.2 billion and comparable funds generated from operations of $5.6 billion were three per cent and nine per cent higher, respectively, in 2017 compared to 2016, primarily due to higher comparable earnings, as described above. In addition, net cash provided by operations was affected by the amount and timing of working capital changes.

Comparable distributable cash flow, reflecting the impact of all maintenance capital expenditures, was $3.6 billion in 2017 compared to $3.5 billion in 2016, primarily due to higher comparable funds generated from operations partially offset by higher maintenance capital. Comparable distributable cash flow, reflecting only non-recoverable maintenance capital, was $5.0 billion in 2017 compared to $4.5 billion in 2016 due primarily to higher comparable funds generated from operations. Comparable distributable cash flow per common share was also impacted by common share issuances in 2016 and 2017. See the Financial condition section for more information on the calculation of comparable distributable cash flow.

Funds used in investing activities

***Capital spending*[1]**

year ended December 31 (millions of $)	2017	2016	2015
Canadian Natural Gas Pipelines	**2,181**	1,525	1,596
U.S. Natural Gas Pipelines	**3,830**	1,522	537
Mexico Natural Gas Pipelines	**1,954**	1,142	566
Liquids Pipelines	**529**	1,137	1,601
Energy	**675**	708	558
Corporate	**41**	33	64
	9,210	6,067	4,922

1 Capital spending includes capacity capital expenditures, maintenance capital expenditures, capital projects in development and contributions to equity investments.

We invested $9.2 billion in capital projects in 2017 to optimize the value of our existing assets and develop new, complementary assets in high demand areas. Our total capital spending in 2017 included contributions of $1.7 billion to our equity investments primarily related to Sur de Texas, Bruce Power, Grand Rapids and Northern Border.

Proceeds from sales of assets

In 2017, we completed the sales of TC Hydro, Ravenswood, Ironwood, Kibby Wind and Ocean State Power for net proceeds of approximately US$3.1 billion, before post-closing adjustments. We also closed the sale of our Ontario solar assets for $541 million, before post-closing adjustments.

Balance sheet

We continue to maintain a solid financial position while growing our total assets by $21.7 billion since 2015. At December 31, 2017, common shareholders' equity represented 33 per cent (31 per cent in 2016) of our capital structure, while other subordinated capital, in the form of junior subordinated notes and preferred shares, represented an additional 16 per cent (12 per cent in 2016). See Financial condition for more information about our capital structure.

Dividends

We increased the quarterly dividend on our outstanding common shares by 10.4 per cent to $0.69 per common share for the quarter ending March 31, 2018 which equates to an annual dividend of $2.76 per common share. This is the 18th consecutive year we have increased the dividend on our common shares and reflects our commitment to growing our common dividend at an average annual rate at the upper end of eight to ten per cent through 2020 and an additional eight to ten per cent in 2021.

Dividend reinvestment plan

Under our DRP, eligible holders of common and preferred shares of TransCanada can reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares. Under this program, common shares are issued from treasury at a discount of two per cent to market prices over a specified period rather than purchased on the open markets to satisfy participation in the DRP.

Cash dividends paid

year ended December 31 (millions of $)	**2017**	2016	2015
Common shares	**1,339**	1,436	1,446
Preferred shares	**155**	100	92

OUTLOOK

Earnings

Our 2018 earnings, after excluding specific items, are expected to be higher than 2017 primarily due to the impact of the following:

- contributions from new Columbia Gas and Columbia Gulf projects coming into service
- full year of earnings from Grand Rapids and Northern Courier placed in service in the latter half of 2017
- completion of the Napanee power plant in Ontario
- growth in the average investment base for the NGTL System
- benefit of lower U.S. income tax rates. See U.S. Tax Reform section for further information.

Partially offset by:

- lower Energy earnings due to the monetization of the U.S. Northeast power generation assets in second quarter 2017, the sale of the Ontario solar assets in late-2017 and the continued wind-down of our U.S. power marketing operations
- lower Bruce Power equity income due to a higher number of planned outage days
- discontinuation of AFUDC on Energy East and related projects
- decrease in Canadian Mainline average investment base.

See relevant business segment outlook for additional details.

Consolidated capital spending and equity investments

We expect to spend approximately $9 billion in 2018 on growth projects, maintenance capital and contributions to equity investments. The majority of the anticipated 2018 capital program will be focused on U.S., Canadian and Mexico natural gas pipeline growth projects and maintenance, with additional capital spend attributable to completing construction on Napanee and contributions to the Bruce Power life extension program and maintenance.

NATURAL GAS PIPELINES BUSINESS

Our natural gas pipeline network transports natural gas from supply basins to local distribution companies, power generation and individual facilities, interconnecting pipelines and other businesses across Canada, the U.S. and Mexico. Our network of pipelines taps into virtually every major supply basin and transports over 25 per cent of continental daily natural gas needs through:

- wholly-owned natural gas pipelines – 80,800 km (50,100 miles)
- partially-owned natural gas pipelines – 11,100 km (7,000 miles).

In addition to our interstate natural gas pipelines, we have regulated natural gas storage facilities in the U.S. with a total working gas capacity of 535 Bcf, making us one of the largest providers of natural gas storage and related services to key markets in North America. We also own and manage midstream services that provide specific natural gas producer services including gathering, treatment, conditioning, processing and liquids handling with a focus on the Appalachian Basin.

Our Natural Gas Pipelines business is split into three operating segments representing its geographic diversity: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Mexico Natural Gas Pipelines.

Strategy at a glance

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

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

- expansion and extension of our existing large North American natural gas pipeline footprint
- connections to new and growing industrial, LDC, LNG export, interconnect and electric power generation markets
- connections to growing Canadian and U.S. shale gas and other supplies
- additional new pipeline developments within Mexico
- greenfield development projects, such as infrastructure for LNG exports from the west coast of Canada and the Gulf of Mexico

Each of these areas plays a critical role in meeting the transportation requirements for supply and demand for natural gas in North America.

Highlights

- In 2017, we placed into service approximately $3.3 billion of new facilities including $1.7 billion on the NGTL System, $0.2 billion on the Canadian Mainline and $1.4 billion related to U.S. Natural Gas Pipelines
- In 2017, we originated an additional US$0.3 billion of capital projects related to U.S. Natural Gas Pipelines
- In June 2017, we announced a new $2 billion expansion program on our NGTL System based on new contracted customer demand for approximately 3 Bcf/d of incremental firm receipt and delivery services
- In July 2017, we were notified that Pacific Northwest (PNW) LNG would not be proceeding with their proposed LNG project and that Progress Energy would be terminating their agreement with us for development of the Prince Rupert Gas Transmission (PRGT) project. In accordance with the terms of the agreement, we received a payment of $0.6 billion from Progress Energy in October 2017 for full recovery of our costs plus carrying charges.
- In November 2017, we began delivering volumes under the new Dawn Long-Term Fixed-Price (LTFP) service on the Canadian Mainline
- In December 2017, we filed, subject to NEB approval, a Supplemental Agreement for the Canadian Mainline to address 2018 to 2020 tolls, to meet a condition of the NEB approval for the 2015 - 2030 Tolls and Tariff Application
- In January 2018, the Columbia Gas Leach XPress project was placed in service
- In February 2018, we announced an additional $2.4 billion expansion program on our NGTL System.

UNDERSTANDING OUR 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 pipelines business builds, owns and operates a network of natural gas pipelines across North America that connects gas production to interconnects and end use markets. The network includes underground pipelines that transport natural gas predominantly under high pressure, compressor stations that act like pumps to move the large volumes of natural gas along the pipeline, meter stations that record the amount of natural gas coming on the network at receipt locations and leaving the network at delivery locations, and natural gas storage facilities that provide services to customers and help maintain the overall balance of the pipeline systems.

Our Major Pipeline Systems

The Natural Gas Pipelines map on page 27 shows our extensive pipeline network in North America that connects major supply sources and markets. The highlights shown on the map include:

NGTL System: This is our natural gas gathering and transportation system for the WCSB, connecting most of the natural gas production in western Canada to domestic and export markets. We believe we are very well positioned to connect growing supply in northeast B.C. and northwest Alberta. It is these two supply areas, along with growing demand for firm transportation in the oil sands area and to our major export points at Empress and Alberta/B.C. delivery locations, that is driving our large capital program for new pipeline facilities. The NGTL System is also well positioned to connect WCSB supply to potential LNG export facilities on the Canadian west coast.

Canadian Mainline: This is a major pipeline that was originally designed as a long haul delivery system transporting supply from the WCSB across Canada to Ontario and Québec to deliver gas to downstream Canadian and U.S. markets. The Canadian Mainline continues this role and is also growing to accommodate additional supply connections closer to its markets.

Columbia Gas: This is our natural gas transportation system for the Appalachian Basin, which contains the Marcellus and Utica shale plays, two of the fastest growing natural gas shale plays in North America. Similar to our footprint in the WCSB, our Columbia assets are very well positioned to connect growing supply and market in this area. This system also interconnects with other pipelines that provide access to key markets in the U.S. Northeast and south to the Gulf of Mexico and its growing demand for natural gas to serve LNG exports. Access to markets from producers in the region is driving the large capital program for new pipeline facilities on this system.

ANR Pipeline System: ANR is our pipeline system that connects supply basins and markets throughout the U.S. Midwest, and south to the Gulf of Mexico. This includes connecting supply in Texas, Oklahoma, the Appalachian Basin and the Gulf of Mexico to markets in Wisconsin, Michigan, Illinois and Ohio. In addition, ANR has bi-directional capability on its Southeast Mainline and delivers gas produced from the Appalachian basin to customers throughout the Gulf Coast Region.

Columbia Gulf: This is our pipeline system originally designed as a long haul delivery system transporting supply from the Gulf of Mexico to major demand markets in the U.S. Northeast. The pipeline is now transitioning to a north-to-south flow and expanding to accommodate new supply in the Appalachian Basin and its interconnects with Columbia Gas and other pipelines to deliver gas to various Gulf Coast markets.

Mexico Pipeline Network: We also have a growing network of natural gas pipelines coupled with a large portfolio of projects under construction in Mexico, including Tula and Villa de Reyes and the 60 per cent-owned Sur de Texas pipeline project through our joint venture with IEnova.

Regulation of tolls and cost recovery

Our natural gas pipelines are generally regulated by the NEB in Canada, by the FERC in the U.S. and by the CRE in Mexico. 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 for services. These tolls generally 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, income and property taxes and interest on debt. The regulator reviews our costs to ensure they are reasonable and prudently incurred and approves tolls that provide us a reasonable opportunity to recover those costs.

Business environment and strategic priorities

The North American natural gas pipeline network has been developed to connect diverse supply regions to domestic markets and, increasingly, to meet demand from LNG export facilities. 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 significant pipeline footprints that serve the two most prolific supply regions of North America, the WCSB and the Appalachian Basin. Our pipelines also source natural gas, to a lesser degree, from other significant basins including the Rockies, Williston, Haynesville, Fayetteville and Anadarko as well as the Gulf of Mexico. We expect continued growth in North American natural gas production to meet demand within growing domestic markets, particularly in the electric generation and industrial sectors which benefit from a relatively low natural gas price. In addition, North American supply is expected to benefit from access to international markets via LNG exports. We expect North American natural gas demand, including LNG exports, of approximately 105 Bcf/d by 2020, reflecting an increase of approximately 10 Bcf/d from 2017 levels.

This expected increased demand for natural gas, coupled with the annual decline rate of 15 per cent to 20 per cent for natural gas production, implies up to 25 Bcf/d of new production per year will be required, providing investment opportunities for pipeline infrastructure companies to build new facilities or increase utilization of the existing footprint.

Changing demand

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

- natural gas-fired electric-power generation
- petrochemical and industrial facilities
- the production of Alberta oil sands, despite new greenfield oil sands projects that have not yet begun construction or have been delayed in the recent low oil price environment
- exports to Mexico to fuel power generation facilities.

Natural gas producers continue to progress opportunities to sell natural gas to global markets which involves connecting natural gas supplies to proposed LNG export terminals along the U.S. Gulf Coast and the west coast of Canada. 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 natural gas pipelines business is not directly tied to commodity prices given we are a transporter of the commodity and the fixed transportation costs are not tied to the price of natural gas. However, the cyclical supply and demand nature of commodities and related pricing can have an indirect impact on our business where producers may choose to accelerate or delay exploration or, similarly on the demand side, projects requiring natural gas may be accelerated or delayed depending on market or price conditions. For example, lower natural gas prices have allowed this commodity to gain market share versus coal in serving power generation markets and to compete globally through LNG exports.

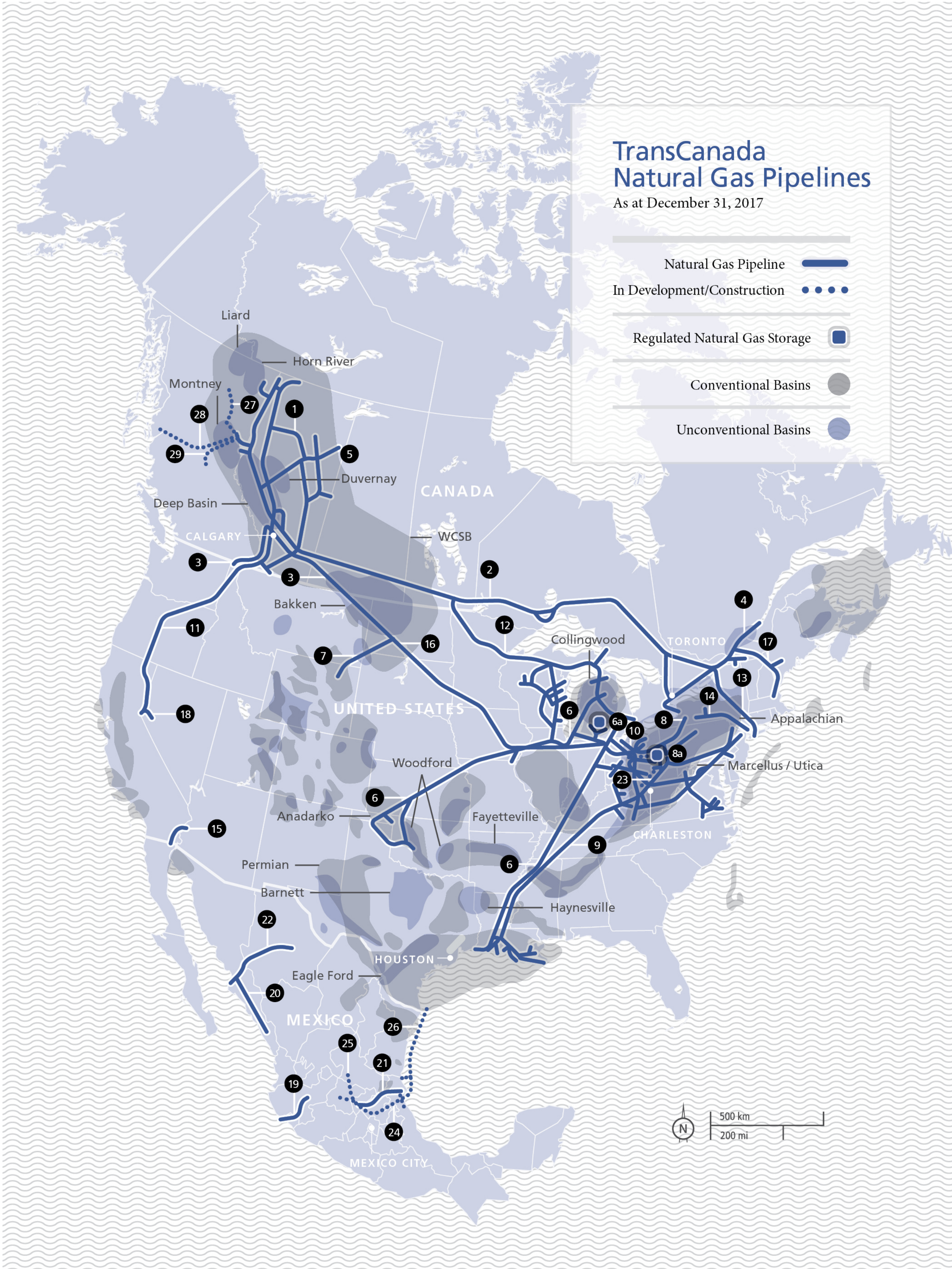
More competition

Changes in supply and demand levels and locations have resulted in increased competition for transportation services throughout North America. With our well-distributed footprint of natural gas pipelines, and particularly our new presence in the growing Appalachian region, we are well positioned to compete. Incumbent pipelines in an area benefit from owning existing right-of-way and infrastructure given the increasing challenges of siting and permitting for new pipeline construction and expansions. We have, and will continue to assess, further opportunities to restructure our tolls and service offerings to capture growing supply and North American demand that now includes access to world markets through LNG exports.

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 natural gas flow dynamics.

In 2018, one of our key focus areas will be the continued execution of our existing capital program that includes further expansion of the NGTL System as well as concluding several projects on the Columbia Gas and Gulf systems and in Mexico. Our goal is to place all of our projects in service on time and on budget while ensuring the safety of our staff, contractors, and all stakeholders impacted by the construction and operation of these facilities.


TransCanada
Natural Gas Pipelines
As at December 31, 2017
Natural Gas Pipeline
In Development/Construction
Regulated Natural Gas Storage
Conventional Basins
Unconventional Basins
Liard
Horn River
Montney
Duvernay
Deep Basin
CALGARY
CANADA
WCSB
Bakken
Collingwood
TORONTO
Appalachian
Marcellus / Utica
UNITED STATES
Woodford
Anadarko
Fayetteville
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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	24,320 km (15,112 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	14,077 km (8,747 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 the Canadian Mainline near the Ontario/Québec border to transport natural gas to the Montréal to Québec City corridor, and interconnects with the Portland pipeline system that serves the northeast U.S.	50%
5	Ventures LP	161 km (100 miles)	Transports natural gas to the oil sands region near Fort McMurray, Alberta. It also includes a 27 km (17 mile) pipeline supplying natural gas to a petrochemical complex at Joffre, Alberta.	100%
*	Great Lakes Canada	58 km (36 miles)	Transports natural gas from the Great Lakes system in the U.S. to Ontario, near Dawn, through a connection at the U.S. border underneath the St. Clair River.	100%
	U.S. pipelines			
6	ANR	15,109 km (9,388 miles)	Transports natural gas from various supply basins to markets throughout the Midwest and Gulf Coast.	100%
6a	ANR Storage	250 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key mid-western markets.	
7	Bison	488 km (303 miles)	Transports natural gas from the Powder River Basin in Wyoming to Northern Border in North Dakota. We effectively own 25.7 per cent of the system through our interest in TC PipeLines, LP.	25.7%
8	Columbia Gas	18,113 km (11,255 miles)	Transports natural gas from supply primarily in the Appalachian Basin to markets throughout the U.S. Northeast.	100%
8a	Columbia Storage	285 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key eastern markets. We also own a 50 per cent interest in the 12 Bcf Hardy Storage facility.	100%
*	Midstream	295 km (183 miles)	Provides infrastructure between the producer upstream well-head and the downstream (interstate pipeline and distribution) sector and includes a 47.5 per cent interest in Pennant Midstream.	100%
9	Columbia Gulf	5,377 km (3,341 miles)	Transports natural gas to various markets and pipeline interconnects in the southern U.S. and Gulf Coast.	100%
10	Crossroads	325 km (202 miles)	Interstate natural gas pipeline operating in Indiana and Ohio with multiple interconnects to other pipelines.	100%
11	Gas Transmission Northwest (GTN)	2,216 km (1,377 miles)	Transports WCSB and Rockies natural gas to Washington, Oregon and California. Connects with Tuscarora and Foothills. We effectively own 25.7 per cent of the system through our interest in TC PipeLines, LP.	25.7%
12	Great Lakes	3,404 km (2,115 miles)	Connects with the Canadian Mainline near Emerson, Manitoba and to Great Lakes Canada near 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 65.5 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 25.7 per cent interest in TC PipeLines, LP.	65.5%
13	Iroquois	669 km (416 miles)	Connects with the Canadian Mainline and serves markets in New York. We effectively own 13.4 per cent of the system through a 0.7 per cent direct ownership and our 25.7 per cent interest in TC PipeLines, LP.	13.4%

		Length	Description	Effective ownership
14	Millennium	407 km (253 miles)	Natural gas pipeline supplied by local production, storage fields and interconnecting upstream pipelines to serve markets along its route and to the U.S. Northeast.	47.5%
15	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 25.7 per cent of the system through our interest in TC PipeLines, LP.	25.7%
16	Northern Border	2,272 km (1,412 miles)	Transports WCSB, Bakken and Rockies natural gas from connections with Foothills and Bison to U.S. Midwest markets. We effectively own 12.9 per cent of the system through our 25.7 per cent interest in TC PipeLines, LP.	12.9%
17	Portland (PNGTS)	475 km (295 miles)	Connects with TQM near East Hereford, Québec to deliver natural gas to customers in the U.S. Northeast. We effectively own 15.9 per cent of the system through our 25.7 per cent interest in TC PipeLines, LP.	15.9%
18	Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to markets in northeastern California and northwestern Nevada. We effectively own 25.7 per cent of the system through our interest in TC PipeLines, LP.	25.7%
	Mexican pipelines			
19	Guadalajara	315 km (196 miles)	Transports natural gas from Manzanillo, Colima to Guadalajara, Jalisco.	100%
20	Mazatlán	430 km (267 miles)	Transports natural gas from El Oro to Mazatlán, Sinaloa in Mexico. Connects to the Topolobampo Pipeline at El Oro.	100%
21	Tamazunchale	375 km (233 miles)	Transports natural gas from Naranjos, Veracruz in east central Mexico to Tamazunchale, San Luis Potosi and on to El Sauz, Querétaro.	100%
22	Topolobampo	560 km (348 miles)	Transports natural gas to Topolobampo, Sinaloa, from interconnects with third-party pipelines in El Oro, Sinaloa and El Encino, Chihuahua in Mexico.	100%
	Under construction			
	Canadian pipelines			
*	NGTL 2018 Facilities	68 km** (42 miles)	An expansion program on the NGTL System including pipeline and compression additions with expected in-service dates by November 2018.	100%
	U.S. pipelines			
23	Mountaineer XPress	275 km** (171 miles)	A Columbia Gas project designed to transport supply from the Marcellus and Utica shale plays to points along the system and to the Leach interconnect with Columbia Gulf.	100%
*	Leach XPress[1]	260 km** (160 miles)	A Columbia Gas project designed to transport supply from the Marcellus and Utica shale plays to points along the system and to an interconnect with Columbia Gulf.	100%
*	Cameron Access	55 km** (34 miles)	A Columbia Gulf project to deliver natural gas from points along the Columbia Gulf system to the Cameron LNG facility.	100%
*	WB XPress	47 km** (29 miles)	A Columbia Gas project designed to transport Marcellus supply both eastbound (to interconnects and mid-Atlantic markets) and westbound (to interconnect pipelines).	100%
*	Gulf XPress	N/A	A Columbia Gulf project associated with the Mountaineer XPress expansion and consisting of the addition of seven greenfield mid-point compressor stations along Columbia Gulf.	100%

	Under construction (continued)	Length	Description	Effective ownership
	Mexican pipelines			
24	Tula	300 km** (186 miles)	The pipeline will originate in Tuxpan in the state of Veracruz and extend through the states of Puebla and Hidalgo, supplying natural gas to CFE combined-cycle power generating facilities in each of those jurisdictions as well as to the central and western regions of Mexico.	100%
25	Villa de Reyes	420 km** (261 miles)	The pipeline will deliver natural gas from Tula, Hildago to Villa de Reyes, San Luis Potosi, connecting to the Tamazunchale and Tula pipelines.	100%
26	Sur de Texas	800 km** (497 miles)	The pipeline will begin offshore in the Gulf of Mexico at the border point near Brownsville, Texas and end in Tuxpan, in the state of Veracruz, connecting with the Tamazunchale and Tula pipelines.	60%
	Permitting and pre-construction phase			
	Canadian pipelines			
27	North Montney	206 km** (128 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.	100%
*	NGTL 2019 Facilities	138 km** (86 miles)	An expansion program on the NGTL System including multiple pipeline projects and compression additions with expected in-service dates by November 2019.	100%
*	NGTL 2020 Facilities	125 km** (78 miles)	An expansion program on the NGTL System including multiple pipeline projects and compression additions with expected in-service dates by November 2020.	100%
*	NGTL 2021 Facilities	401 km** (249 miles)	An expansion program on the NGTL System including multiple pipeline projects and compression additions with expected in-service dates by November 2021.	100%
	U.S. pipelines			
*	Buckeye XPress	103 km** (64 miles)	A Columbia Gas project designed to upgrade and replace existing pipeline and compression facilities in Ohio to transport incremental supply from the Marcellus and Utica shale plays to points along the system.	100%
*	Portland XPress	N/A	A PNGTS project to expand the system through the construction of compression and related facilities at existing compressor stations.	15.9%
	In development			
	Canadian pipelines			
28	Coastal GasLink	670 km** (416 miles)	To deliver natural gas from the Montney gas producing region at an expected interconnect with the NGTL System near Dawson Creek, B.C. to LNG Canada's proposed facility near Kitimat, B.C.	100%
29	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%

1 Leach XPress was placed in service in January 2018.

* Facilities and some pipelines are not shown on the map.
** Final pipe lengths are subject to change during construction and/or final design considerations.

Canadian Natural Gas Pipelines

UNDERSTANDING OUR CANADIAN NATURAL GAS PIPELINES SEGMENT

The Canadian natural gas business is subject to regulation by various federal and provincial governmental agencies. The NEB, however, has comprehensive jurisdiction over our Canadian natural gas business. The NEB approves tolls and services that are in the public interest and provides a reasonable opportunity for a pipeline to recover its costs to operate the pipeline. Included in the overall costs to operate the pipeline is a return on the investment the company has made in the assets, referred to as the return on equity. Equity is generally 40 per cent of the deemed capital structure with the remaining 60 per cent from debt. Typically tolls are based on the cost of providing service divided by a forecast of throughput volumes. Any variance in either costs or the actual volumes transported can result in an over-collection or under-collection of revenue that is normally trued up the following year in the calculation of the tolls for that period. The return on equity, however, would continue to be earned at the rate approved by the NEB.

We and our shippers can also establish settlement arrangements, subject to approval by the NEB, that may have elements that vary from the typical toll-setting process. Settlements can include longer terms and mechanisms such as incentive agreements that can have an impact on the actual return on equity achieved. Examples include fixing the OM&A component in determining revenue requirements, where variances are to the pipeline's account or shared in some fashion between the pipeline and shippers.

The NGTL System concluded its two-year settlement arrangement in 2017 and is currently working with interested parties for a new arrangement for 2018 and longer. The Mainline system is entering the fourth year of a six-year fixed toll settlement that includes an incentive arrangement where it has discretion to price certain of its short-term services, such as interruptible transportation service, at market prices. Settlements of this nature provide the pipeline an incentive to either decrease costs and/or increase revenues on the pipeline with a beneficial sharing mechanism to both the shippers and us.

SIGNIFICANT EVENTS

Canadian Regulated Pipelines

NGTL System

In February 2018, we announced a new NGTL System expansion totaling $2.4 billion, with in-service dates between 2019 and 2021. The new expansion program includes approximately 375 km (233 miles) of 16- to 48-inch pipeline, four compression units totaling 120 MW and associated meter stations and facilities. We anticipate incremental firm receipt contracts of 664 TJ/d (620 MMcf/d) and firm delivery contracts to our major border export and intra-basin delivery locations of 1.1 PJ/d (1.0 Bcf/d).

In June 2017, we announced a new $2 billion expansion program on our NGTL System based on new contracted customer demand for approximately 3.2 PJ/d (3.0 Bcf/d) of incremental firm receipt and delivery services.

With the 2021 expansion program, NGTL now has a $7.2 billion capital program, excluding the $1.9 billion Merrick pipeline project.

In 2017, we placed approximately $1.7 billion of facilities in service and reduced remaining project estimates by $0.6 billion.

Towerbirch Expansion

In March 2017, the Government of Canada approved the $0.4 billion Towerbirch Project. This project consists of a 55 km (34 mile), 36-inch pipeline loop and a 32 km (20 mile), 30-inch pipeline extension of the NGTL System in northwest Alberta and northeast B.C. The NEB approval included the continued use of the existing rolled-in tolling methodology for this project. The project was placed in service in November 2017.

North Montney

In March 2017, we filed an application with the NEB for a variance to the existing approvals for the North Montney Project on the NGTL System to remove the condition that the project could only proceed once a positive FID was made for the PNW LNG project. The North Montney project is now underpinned by restructured 20-year commercial contracts with shippers and is not dependent on the LNG project proceeding. A hearing on the matter began the week of January 22, 2018 and a decision from the NEB is anticipated in second quarter 2018.

Sundre Crossover Project

On December 28, 2017, the NEB approved the Sundre Crossover Project on the NGTL System. The approximate $100 million, 21 km (13 mile), 42-inch pipeline project will increase delivery of 245 TJ/d (229 MMcf/d) to the Alberta / B.C. border to connect with TransCanada downstream pipelines. In-service is planned for April 1, 2018.

NGTL 2018 Revenue Requirement

NGTL's 2016-2017 Settlement, which established revenue requirements for the system, expired on December 31, 2017. We continue to work with interested parties towards a new revenue requirement arrangement for 2018 and longer. While these discussions are underway, NGTL is operating under interim tolls for 2018 that were approved by the NEB on November 24, 2017.

Canadian Mainline

The Canadian Mainline currently has a near-term capital program of approximately $0.2 billion for completion to 2021. In 2017, we placed approximately $0.2 billion of facilities in service, consisting primarily of the Vaughan Loop in November.

Dawn Long-Term Fixed-Price Service

On November 1, 2017, we began offering the new Dawn LTFP service on the Canadian Mainline. This NEB-approved service enables WCSB producers to transport up to 1.5 PJ/d (1.4 Bcf/d) of natural gas at a simplified toll of $0.77/GJ from the Empress receipt point in Alberta to the Dawn hub in Southern Ontario. The service is underpinned by ten-year contracts that have early termination rights after five-years. Any early termination will result in an increased toll for the last two years of the contract.

Canadian Mainline 2018-2020 Toll Review

Tolls for the Canadian Mainline were previously established for 2015 to 2017 in accordance with the terms of the 2015-2030 LDC Settlement. While the settlement specified tolls for 2015 to 2020, the NEB ordered a toll review halfway through the six-year period, to be filed by December 31, 2017. The 2018-2020 toll review must include costs, forecast volumes, contract levels, deferral balances and any other material changes. A Supplemental Agreement for the 2018 to 2020 period was executed between TransCanada and the Eastern LDCs on December 8, 2017 and filed for approval with the NEB on December 18, 2017. The Agreement, supported by a majority of Canadian Mainline stakeholders, proposes lower tolls, preserves an incentive arrangement that provides the opportunity for a 10.1 per cent or greater return on a 40 percent deemed equity and describes the revenue requirements and billing determinants for the 2018-2020 period.

We anticipate the NEB will provide direction and process to adjudicate the application in first quarter 2018. Interim tolls for 2018, as established by the Supplemental Agreement, were filed and subsequently approved by the NEB on December 19, 2017.

Maple Compressor Expansion Project

In 2017, the Canadian Mainline received requests for expansion capacity to the southern Ontario market plus delivery to Atlantic Canada via the TQM and PNGTS systems. The requests for approximately 86 TJ/d (80 MMcf/d) of firm service underpin the need for new compression at the existing Maple compressor site. Customers have executed 15-year precedent agreements to proceed with the project which has an estimated cost of $110 million. An application to the NEB seeking project approval was filed November 2, 2017. We have requested a decision by the NEB to proceed with the project in the first quarter of 2018 to meet an anticipated in-service date of November 1, 2019.

Eastern Mainline Project

The $2 billion Eastern Mainline project that was conditioned on the approval and construction of the Energy East pipeline will not be proceeding. See the Liquids Pipelines Significant events section for further discussion on Energy East.

LNG Pipeline Projects

Prince Rupert Gas Transmission (PRGT)

In July 2017, we were notified that PNW LNG would not be proceeding with their proposed LNG project and that Progress Energy would be terminating their agreement with us for development of the PRGT pipeline. In accordance with the terms of the agreement, all project costs incurred to advance PRGT, including carrying charges, were fully recoverable upon termination and, as a result, we received a payment of $0.6 billion from Progress in October 2017.

Coastal GasLink

The continuing delay in the FID for the LNG Canada project triggered a restructuring of provisions in the Coastal GasLink project agreement with LNG Canada that resulted in the payment of certain amounts to TransCanada with respect to carrying charges on costs incurred. In September 2017, an approximate $80 million payment was received related to costs incurred since inception of the project. Following a payment of $8 million in fourth quarter 2017, additional quarterly payments of approximately $7 million will be received until further notice. We continue to work with LNG Canada under the agreement towards an FID. Coastal GasLink filed an amendment to the Environmental Assessment Certificate in November 2017 for an alternate route on a portion of the pipeline. A decision from the B.C. Environmental Assessment Office is expected in 2018.

Coastal GasLink is a 670 km (416 mile) pipeline that will deliver natural gas from the Dawson Creek, B.C. area to LNG Canada's proposed gas liquefaction facility near Kitimat, B.C. Should the project not proceed, our project costs, including carrying charges, are fully recoverable.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 and 2015 results have been adjusted to reflect this change.

year ended December 31 (millions of $)	**2017**	**2016**	**2015**
NGTL System	**996**	968	900
Canadian Mainline	**1,043**	1,105	1,193
Other Canadian pipelines[1]	**110**	116	131
Business development	**(5)**	(7)	(8)
Comparable EBITDA	**2,144**	2,182	2,216
Depreciation and amortization	**(908)**	(875)	(849)
Comparable EBIT and segmented earnings	**1,236**	1,307	1,367

1 Includes results from Foothills, Ventures LP, Great Lakes Canada, our share of equity income from our investment in TQM, and general and administrative costs related to our Canadian Pipelines.

Canadian Natural Gas Pipelines comparable EBIT and segmented earnings decreased by $71 million in 2017 compared to 2016 and by $60 million in 2016 compared to 2015.

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 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.

year ended December 31 (millions of $)	**2017**	**2016**	**2015**
Net income			
NGTL System	**352**	318	269
Canadian Mainline	**199**	208	213
Average investment base			
NGTL System	**8,385**	7,451	6,698
Canadian Mainline	**4,184**	4,441	4,784

Net income for the NGTL System was $34 million higher in 2017 compared to 2016 mainly due to a higher average investment base, partially offset by higher carrying charges on regulatory deferrals. Net income in 2016 was $49 million higher than 2015 due to a higher average investment base and increased OM&A incentive earnings recorded in 2016. The two-year 2016-2017 Revenue Requirement Settlement included an ROE of 10.1 per cent on 40 per cent deemed equity and a mechanism for sharing variances above and below a fixed annual OM&A amount with flow-through treatment of all other costs. The 2015 NGTL Settlement included a 10.1 per cent ROE on deemed common equity of 40 per cent and a mechanism for sharing variances between actual and a fixed OM&A cost amount.

Canadian Mainline's net income in 2017 decreased by $9 million compared to 2016 mainly due to a lower average investment base and higher carrying charges to shippers on the 2017 net revenue surplus, partially offset by higher incentive earnings in 2017. Net income in 2016 was $5 million lower than 2015 mainly due to a lower average investment base and higher carrying charges to shippers on the 2016 net revenue surplus, partially offset by higher incentive earnings in 2016. The lower average investment base in 2017 and 2016 was mainly due to depreciation and the inclusion of the 2016 and 2015 net revenue surpluses in the investment base.

The Canadian Mainline operated under the NEB 2014 Decision throughout 2015 to 2017. The NEB 2014 Decision included an approved ROE of 10.1 per cent with a possible range of achieved ROE outcomes between 8.7 per cent and 11.5 per cent. This decision also included an incentive mechanism that has both upside and downside risk and a $20 million annual after-tax contribution from us. Toll stabilization is achieved through the continued use of deferral accounts to capture the surplus or shortfall between our revenues and cost of service for each year over a six-year fixed toll term from 2015 to 2020.

Depreciation and amortization

Depreciation and amortization was $33 million higher in 2017 compared to 2016, and $26 million higher in 2016 compared to 2015, primarily due to new NGTL System facilities that were placed in service in both 2017 and 2016.

OUTLOOK

Earnings

Net income for Canadian rate-regulated pipelines is affected by changes in investment base, ROE and regulated capital structure, as well as by the terms of toll settlements or other toll proposals approved by the NEB.

Canadian Natural Gas Pipelines earnings in 2018 are expected to be modestly lower than 2017 due to a declining Canadian Mainline investment base and lower incentive earnings, partially offset by continued growth in the NGTL System. We expect the NGTL System investment base to continue to grow as we extend and expand the northwest supply facilities, northeast delivery facilities and incremental service at our major border delivery locations in response to requests for both receipt and delivery firm service on the system.

In accordance with the terms of the 2015-2030 LDC Settlement, the Canadian Mainline is subject to a toll review for 2018 to 2020. A Supplemental Agreement for the 2018 to 2020 period was executed and filed for approval with the NEB in December 2017. Interim tolls were filed and subsequently approved by the NEB in December 2017.

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 systems 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.

Capital spending

We spent a total of $2.2 billion in 2017 for our Canadian Natural Gas Pipelines and expect to spend approximately $1.7 billion in 2018 primarily on the NGTL System expansion projects, Canadian Mainline capacity projects and maintenance capital which are all immediately reflected in investment base.

U.S. Natural Gas Pipelines

UNDERSTANDING OUR U.S. NATURAL GAS PIPELINES SEGMENT

The U.S. interstate natural gas pipeline business is subject to regulation by various federal, state and local governmental agencies. The FERC, however, has comprehensive jurisdiction over our U.S. natural gas business. The FERC approves maximum transportation rates that are cost based and are designed to recover the pipeline's investment, operating expenses and a reasonable return for our investors. In the U.S., we have the ability to contract for negotiated or discounted rates with shippers.

The FERC does not require U.S. interstate pipelines to calculate rates annually, nor do they generally allow for the collection or refund of the variance between actual and expected revenues and costs into future years. This difference in U.S. regulation from the Canadian regulatory environment 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 or our shippers may institute proceedings to lower rates if they consider the return on the capital invested to be too high.

Similar to Canada, we can also establish settlement arrangements with our U.S. shippers that are ultimately subject to approval by the FERC. Rate case moratoriums for a period of time before either we or the shippers can file for a rate review are common for a settlement in that it provides some certainty for shippers in terms of rates, eliminates the costs associated with a rate proceeding for all parties and can provide an incentive for pipelines to lower costs.

Additionally, we operate a non-regulated Midstream business that provides midstream services including gathering, treating, conditioning, processing, compression and liquids handling in the Appalachian Basin. The Midstream footprint consists of over 300 km (186 miles) of pipeline ranging in size from 16 to 36 inches. Midstream also manages our small mineral rights positions in the Marcellus and Utica shale areas.

TransCanada's Master Limited Partnership

We own, through subsidiaries, a 25.7 per cent effective ownership in TC PipeLines, LP, a MLP which trades on the New York Stock Exchange under the symbol TCP. TC PipeLines, LP has ownership interests in the GTN, Northern Border, Bison, Great Lakes, North Baja, Tuscarora, Iroquois, and PNGTS pipeline systems. Our overall effective ownership for each of these assets considering the ownership through the MLP is provided in the asset listing of our major pipelines starting on page 28.

SIGNIFICANT EVENTS

Leach XPress

Leach XPress was placed in service January 1, 2018. This Columbia Gas project transports approximately 1.6 PJ/d (1.5 Bcf/d) of Marcellus and Utica gas supply to delivery points along the system.

Rayne XPress

Rayne Xpress was placed in service November 2, 2017. This Columbia Gulf project transports approximately 1.1 PJ/d (1.0 Bcf/d) of supply from an interconnect with the Leach XPress pipeline project, and another interconnect, to markets along the system and to the Gulf Coast.

Modernization I & II

Columbia Gas and its customers have entered into a settlement arrangement, approved by the FERC, which provides recovery and return on investment to modernize its system, improve system integrity, and enhance service reliability and flexibility. The modernization program includes, among other things, replacement of aging pipeline and compressor facilities, enhancements to system inspection capabilities, and improvements to control systems. The US$1.5 billion Modernization I arrangement was completed under the terms of the 2012 Settlement Agreement, with the final US$0.2 billion spent in 2017. Modernization II has been approved for up to US$1.1 billion of work starting in 2018 and to be completed in 2020. As per terms of the arrangements, facilities in service by October 31 collect revenues effective February 1 of the following year.

Buckeye XPress

The Buckeye XPress project (BXP) represents an upsizing of an existing pipeline replacement project in conjunction with our Columbia Gas modernization program. The US$0.2 billion cost to upsize the replacement pipe and install compressor upgrades will enable us to offer 290 TJ/d (275 MMcf/d) of incremental pipeline capacity to accommodate growing Appalachian production. We expect BXP to be placed in service in late-2020.

Mountaineer XPress Project

The Mountaineer XPress project (MXP), a Columbia Gas project designed to transport approximately 2.9 PJ/d (2.7 Bcf/d) of Marcellus and Utica gas supply to delivery points along the pipeline and to the Leach interconnect with Columbia Gulf, is expected to be placed in service in fourth quarter 2018. The current estimated project cost of US$2.6 billion reflects an increase in construction cost estimates of US$0.6 billion. As a result of a cost sharing mechanism, overall project returns are not anticipated to be materially affected.

Gibraltar

Gibraltar, a Midstream project to construct a 1,000 TJ/d (934 MMcf/d) dry gas header pipeline in southwest Pennsylvania, was placed in service November 1, 2017.

Portland XPress

PNGTS has executed precedent agreements with several LDCs in New England and Atlantic Canada to re-contract certain system capacity set to expire in 2019, as well as expand the PNGTS system to bring its certificated capacity from 222 TJ/d (210 MMcf/d) to 290 TJ/d (275 MMcf/d). The approximately US$80 million Portland XPress Project (PXP) will proceed concurrently with upstream capacity expansions. The in-service dates of PXP are being phased-in over a three-year period beginning November 1, 2018.

FERC Update

The FERC regained a quorum of three commissioners in August 2017 and two additional commissioners were approved by the U.S. Senate on November 2, 2017. The FERC has stated that it intends to expeditiously address the resulting backlog of pending applications. The FERC certificate for WB XPress was received in November 2017 and the FERC certificates for MXP and Gulf XPress projects were received on December 29, 2017.

Great Lakes

Rate Case

On October 30, 2017, Great Lakes filed a rate settlement with the FERC to satisfy its obligations from its 2013 rate settlement for new rates to be in effect by January 1, 2018. The 2017 Great Lakes Settlement, if approved by the FERC, will decrease Great Lakes' maximum transportation rates by 27 per cent beginning October 1, 2017. Great Lakes expects that the impact from other changes, including the recent long-term transportation contract with the Canadian Mainline as described below, other revenue opportunities on the system and the elimination of the revenue sharing mechanism with its customers, will essentially offset the full year impact of the reduction in Great Lakes' rates beginning in 2018.

Impact of Dawn LTFP

In conjunction with the Canadian Mainline's LTFP service, Great Lakes entered into a new ten-year gas transportation contract with the Canadian Mainline. This contract received NEB approval in September 2017, effective November 1, 2017, and contains volume reduction options up to full contract quantity beginning in year three.

Northern Border Settlement

Northern Border filed a rate settlement with the FERC on December 4, 2017, reflecting a settlement-in-principle with its shippers, which precludes the need to file a general rate case as contemplated by its previous 2012 settlement. Northern Border anticipates that the FERC will accept the settlement agreement and that it will be unopposed. This is expected to provide Northern Border with rate stability over the longer term. We have a 12.9 per cent indirect ownership interest in Northern Border through TC PipeLines, LP.

Sale of Iroquois and PNGTS to TC PipeLines, LP

In June 2017, we closed the sale of 49.34 per cent of our 50 per cent interest in Iroquois, along with an option to sell the remaining 0.66 per cent at a later date, to TC PipeLines, LP. At the same time, we closed the sale of our remaining 11.81 per cent interest in PNGTS to TC PipeLines, LP. Proceeds from these transactions were US$765 million, before post-closing adjustments. Proceeds were comprised of US$597 million in cash and US$168 million representing a proportionate share of Iroquois and PNGTS debt.

Columbia Pipeline Partners LP

In February 2017, we completed the acquisition, for cash, of all outstanding publicly held common units of CPPL at a price of US$17.00 and a stub period distribution payment of US$0.10 per common unit for an aggregate transaction value of US$921 million.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 and 2015 results have been adjusted to reflect this change.

year ended December 31 (millions of US$, unless otherwise noted)	**2017**	**2016**	**2015**
Columbia Gas[1]	**623**	269	—
ANR	**400**	321	220
TC PipeLines, LP[2,3]	**110**	118	106
Midstream[1]	**93**	40	—
Columbia Gulf[1]	**76**	25	—
Great Lakes[3,4]	**64**	60	63
Other U.S. pipelines[1,2,3,5]	**108**	74	87
Non-controlling interests[6]	**341**	365	292
Business development	**(2)**	(3)	(12)
Comparable EBITDA	**1,813**	1,269	756
Depreciation and amortization	**(453)**	(322)	(194)
Comparable EBIT	**1,360**	947	562
Foreign exchange impact	**410**	310	160
Comparable EBIT (Cdn$)	**1,770**	1,257	722
Specific items:			
Integration and acquisition related costs - Columbia	**(10)**	(63)	—
TC Offshore loss on sale	**—**	(4)	(125)
Segmented earnings (Cdn$)	**1,760**	1,190	597

1 We completed the acquisition of Columbia on July 1, 2016. Results reflect our effective ownership in these assets from that date.

2 Results from Northern Border and Iroquois reflect our share of equity income from these investments. We acquired additional interests in Iroquois of 4.87 per cent on March 31, 2016 and 0.65 per cent on May 1, 2016. TC PipeLines, LP acquired 49.34 per cent of our 50 per cent interest in Iroquois on June 1, 2017. On January 1, 2016, we sold a 49.9 per cent direct interest in PNGTS to TC PipeLines, LP and the remaining 11.81 per cent to TC PipeLines, LP on June 1, 2017. On April 1, 2015, we sold our remaining 30 per cent direct interest in GTN to TC PipeLines, LP.

3 TC PipeLines, LP periodically conducts at-the-market equity issuances which decrease our ownership in TC PipeLines, LP. The following shows our ownership interest in TC PipeLines, LP and our effective ownership interest of Great Lakes and PNGTS through our ownership interest in TC PipeLines, LP at the dates presented.

	Effective ownership percentage as of		
	December 31, 2017	**December 31, 2016**	**December 31, 2015**
TC PipeLines, LP	25.7	26.8	28.0
Effective ownership through TC PipeLines, LP:			
Great Lakes	11.9	12.5	13.0
PNGTS	15.9	13.4	—

4 Represents our 53.6 per cent direct interest in Great Lakes. The remaining 46.4 per cent is held by TC PipeLines, LP.

5 Includes our direct ownership in Iroquois and PNGTS (until June 1, 2017) and GTN (until April 1, 2015), our effective ownership in Millennium and Hardy Storage, and general and administrative costs related to U.S. natural gas assets.

6 Comparable EBITDA for the portions of TC PipeLines, LP, PNGTS (until June 1, 2017), and CPPL we do not own. Effective February 17, 2017, we acquired the remaining publicly held units of CPPL.

U.S. Natural Gas Pipelines segmented earnings in 2017 increased by $570 million compared to 2016 and increased by $593 million in 2016 compared to 2015. Segmented earnings in 2017 included pre-tax costs of $10 million (2016 - $63 million) mainly related to retention and severance expenses resulting from the Columbia acquisition. Segmented earnings in 2016 and 2015 also included pre-tax losses of $4 million and $125 million, respectively, as a result of a December 2015 agreement to sell TC Offshore, which closed in March 2016. These amounts have been excluded from our calculation of comparable EBIT and comparable earnings.

Earnings from our U.S. Natural Gas Pipelines operations, which include Columbia effective July 1, 2016, are generally affected by contracted volume levels, volumes delivered and the rates charged as well as by the cost of providing services. Columbia and ANR results are also affected by the contracting and pricing of their storage capacity and incidental commodity sales. Pipeline and storage volumes and revenues are generally higher in the winter months because of the seasonal nature of the business.

Comparable EBITDA for U.S. Natural Gas Pipelines was US$544 million higher in 2017 than 2016 primarily due to the net effect of:

- a full year contribution from Columbia
- higher ANR transportation revenue resulting from a FERC-approved rate settlement, effective August 1, 2016.

Comparable EBITDA for U.S. Natural Gas Pipelines was US$513 million higher in 2016 than 2015 primarily due to the net effect of:

- incremental earnings from Columbia as a result of the acquisition on July 1, 2016
- higher ANR transportation revenue resulting from a FERC-approved rate settlement, effective August 1, 2016, higher Southeast Mainline transportation revenues and lower pipeline integrity work on ANR, partially offset by lower incidental commodity sales and a one time settlement in 2015 with an owner of adjacent facilities for commercial interruption of ANR's service
- higher contributions from TC PipeLines, LP mainly due to higher GTN transportation revenues.

Depreciation and amortization

Depreciation and amortization was US$131 million higher in 2017 compared to 2016, and US$128 million higher in 2016 compared to 2015, primarily due to our acquisition of Columbia and increased depreciation rates on ANR following its rate settlement effective August 1, 2016.

OUTLOOK

Earnings

U.S. Natural Gas Pipelines 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, as well as broader conditions that impact demand from certain customers or market segments. Earnings are also affected by the level of operational and other costs, which include the impact of safety, environmental and other regulators' decisions.

Our U.S. natural gas pipelines are largely backed by long-term take-or-pay contracts that are expected to deliver stable and consistent financial performance.

U.S. Natural Gas Pipelines earnings are expected to be higher in 2018 than in 2017 due to, among other factors, increased revenues following the completion of expansion projects on the Columbia Gas and Columbia Gulf systems. These projects provide our customers with increased access to new sources of supply while extending their market reach. Further, we continue to pursue expansions across our existing geographical footprint that are expected to allow for the transport of constrained natural gas production in the Marcellus and Utica producing regions to areas of demand.

ANR is positioned to continue to benefit from its combination of long-term contracts originating in the Utica and Marcellus shale plays, a broad reach of storage and transmission services to customers in the Midwest, and its connectivity to Gulf Coast area production and end-use markets. We expect ANR to provide stable earnings for 2018 compared to 2017.

Great Lakes, Northern Border and GTN have benefited from market conditions through 2017 that have maintained the value of their services. Further, both Great Lakes and Northern Border have filed rate settlements with the FERC on October 30, 2017 and December 4, 2017, respectively. These settlements are expected to provide rate certainty and predictable earnings through 2018 and beyond.

We continue to seek opportunities to expand on these developments, along with continued growth in end-use markets for natural gas, as we examine commercial, regulatory and operational changes to optimize our pipelines' positions in response to positive developments in supply fundamentals.

Capital spending

We spent a total of US$3.2 billion in 2017 on our U.S. Natural Gas Pipelines and expect to spend approximately US$4.1 billion in 2018 primarily on Columbia Gas and Columbia Gulf expansion projects as well as ANR and Columbia Gas maintenance capital, the majority of which we expect to recover in future tolls.

Mexico Natural Gas Pipelines

UNDERSTANDING OUR MEXICO NATURAL GAS PIPELINES SEGMENT

For over a decade, Mexico has been undergoing a significant transition from using fuel oil and diesel to using natural gas as its primary energy source for electric generation. As a result, new natural gas pipeline infrastructure is required to meet the growing demand for natural gas. Large natural gas pipelines in Mexico have been developed primarily through a competitive bid process whereby pipeline companies propose a cash flow stream over a 25-year contract based on their estimate of construction and ongoing operating costs. The revenues in these 25-year contracts are predominately denominated in U.S. dollars and are underpinned by the CFE, Mexico's electric utility. The pipeline operator is at risk for the construction and ongoing operating costs and is subject to penalties, excluding force majeure claims, if the project is not ready for in-service by a specific date.

Our Mexican pipelines have approved tariffs, services and related rates for other potential users of the pipeline. Most of the contracts that currently underpin the construction and operation of the facilities in Mexico are long-term, fixed-rate contracts designed to recover the cost of our service.

SIGNIFICANT EVENTS

Topolobampo

The Topolobampo project is substantially complete, excluding a 20 km (12 mile) section due to delays experienced by the Secretary of Energy, the governmental department which conducts indigenous consultations in Mexico. The issue has been resolved and construction on this final section is expected to be completed in the second quarter of 2018.

The overall project is a 560 km (348 mile), 30-inch pipeline with a cost of US$1.2 billion, an increase of US$0.2 billion from the original estimate due to the delays from the force majeure event. The project will receive natural gas from upstream pipelines near El Encino, in the state of Chihuahua, and deliver natural gas from these interconnecting pipelines to delivery points along the pipeline route including our Mazatlán pipeline at El Oro, in the state of Sinaloa. Construction of the pipeline is supported by a 25-year natural gas TSA for 717 TJ/d (670 MMcf/d) with the CFE. Under the terms of the TSA, the delay in the 20 km (12 mile) section was recognized as a force majeure event with provisions allowing for the collection of revenue from the original TSA service commencement date of July 2016.

Mazatlán

The Mazatlán project was commissioned and brought into full service in July 2017. The project is a 430 km (267 mile), 24-inch pipeline running from El Oro to Mazatlán within the state of Sinaloa with a cost of US$0.4 billion. The pipeline is supported by a 25-year natural gas TSA for 214 TJ/d (200 MMcf/d) with the CFE and is awaiting continuous natural gas supply from upstream, third-party interconnecting pipelines, however, our contractual obligations have been met and therefore, the collection and recognition of revenue began under the terms of the TSA in December 2016.

Tula

The Tula project is a US$0.7 billion, 36-inch, 300 km (186 mile) pipeline with a 16-inch, 24 km (15 mile) lateral, supported by a 25-year natural gas TSA for 949 TJ/d (886 MMcf/d) with the CFE. The pipeline will transport natural gas from Tuxpan, Veracruz to markets near Tula, Querétaro extending through the states of Puebla and Hidalgo. Project completion has been revised to late 2019 due to delays experienced by the Secretary of Energy, the governmental department which conducts indigenous consultations in Mexico. Construction of the Tula pipeline was substantially completed in 2017 with the exception of approximately 90 km (56 miles) of the pipeline. The delay has been recognized by the CFE as a force majeure event and we are finalizing amending agreements to formalize the schedule and payment impacts. As a result of the delay and increased cost of land and permitting, estimated project costs have increased by US$0.1 billion from the original estimate.

Villa de Reyes

The Villa de Reyes project is a US$0.8 billion project with 36- and 24-inch pipelines totaling 420 km (261 miles), supported by a 25-year natural gas TSA for 949 TJ/d (886 MMcf/d) with the CFE. The bi-directional pipeline will transport natural gas between Tula, in the state of Hidalgo, and Villa de Reyes, in the state of San Luis Potosí. The project will interconnect with our Tamazunchale and Tula pipelines as well as with other transporters in the region. Construction of the project has commenced, however, delays due to archeological investigations by federal authorities have caused the in-service date of the project to be revised to late 2018. The delay has been recognized as a force majeure event by the CFE and we are finalizing amending agreements to formalize the schedule and payment impacts. As a result of the delay and increased cost of land and permitting, estimated project costs have increased by US$0.2 billion from the original estimate.

Sur de Texas

The US$2.1 billion Sur de Texas project is a joint venture with IEnova in which we hold a 60 per cent interest, representing an investment of approximately US$1.3 billion. Construction of the pipeline is supported by a 25-year natural gas TSA for 2.8 PJ/d (2.6 Bcf/d) with the CFE. Pipeline construction on the 42-inch diameter, approximately 800 km (497 mile) pipeline is progressing toward an anticipated in-service date of late 2018, with approximately 60 per cent of the off-shore construction completed as of the end of 2017. The pipeline will start offshore in the Gulf of Mexico, at the border point near Brownsville, Texas, and end in Tuxpan, in the state of Veracruz. The project will deliver natural gas to our Tamazunchale and Tula pipelines and to other transporters in the region.

TransGas

In 2017, we recognized an impairment charge of $12 million on our 46.5 per cent equity investment in TransGas de Occidente S.A. (TransGas). TransGas constructed and operated a natural gas pipeline in Colombia over a 20-year build-own-transfer contract term. As per the terms of the agreement, upon completion of the 20-year contract in August 2017, TransGas transferred its pipeline assets to Transportadora de Gas Internacional S.A.. The impairment charge represents the write-down of the remaining carrying value of our equity investment.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 and 2015 results have been adjusted to reflect this change.

year ended December 31 (millions of US$, unless otherwise noted)	**2017**	**2016**	**2015**
Tamazunchale	**112**	105	108
Topolobampo	**157**	81	(3)
Guadalajara	**68**	67	69
Mazatlán	**65**	5	(2)
Sur de Texas[1]	**8**	—	—
Other	**(11)**	(3)	4
Business development	**—**	(5)	(12)
Comparable EBITDA	**399**	250	164
Depreciation and amortization	**(72)**	(35)	(34)
Comparable EBIT	**327**	215	130
Foreign exchange impact	**99**	72	39
Comparable EBIT and segmented earnings (Cdn$)	**426**	287	169

1 Represents our 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline.

Mexico Natural Gas Pipelines segmented earnings in 2017 increased by $139 million compared to 2016 and increased by $118 million in 2016 compared to 2015.

Comparable EBITDA for Mexico Natural Gas Pipelines was US$149 million higher in 2017 than 2016 mainly due to the net effect of:

- incremental earnings from Topolobampo beginning July 2016 and Mazatlán beginning December 2016
- equity earnings from our investment in the Sur de Texas pipeline which records AFUDC during construction, net of interest expense on an inter-affiliate loan from TransCanada. The inter-affiliate loan interest is fully offset in interest income and other in the Corporate segment.
- the impairment of our equity investment in TransGas.

Comparable EBITDA for Mexico Natural Gas Pipelines was US$86 million higher in 2016 than 2015 primarily due the net effect of:

- incremental earnings from Topolobampo. The Topolobampo project experienced a delay in construction which, under the terms of our TSA with the CFE, constitutes a force majeure event with provisions allowing for the collection and recognition of revenue as per the original TSA service commencement date of July 2016
- incremental earnings from Mazatlán. Construction is complete and the collection and recognition of revenue began per the terms of the TSA in December 2016
- lower business development costs expensed in 2016 due to the capitalization of costs for work on projects successfully awarded and under construction.

Depreciation and amortization

Depreciation and amortization increased by US$37 million in 2017 compared to 2016 primarily due to the commencement of depreciation on Topolobampo and Mazatlán. Depreciation and amortization remained consistent in 2016 compared to 2015.

OUTLOOK

Earnings

Mexico Natural Gas Pipelines earnings reflect long-term, stable, principally U.S. dollar denominated revenue contracts that are affected by the cost of providing service and include our share of equity income from our 60 per cent effective interest in the Sur de Texas pipeline project.

We expect 2018 earnings from the Topolobampo, Tamazunchale, Guadalajara and Mazatlán pipelines to remain consistent with 2017 due to the long-term nature of the underlying revenue contracts. Sur de Texas and Villa de Reyes are expected to be in service in late 2018.

Capital spending

We spent a total of US$1.5 billion in 2017 for our Mexican natural gas pipeline capital projects and expect to spend approximately US$0.7 billion in 2018, primarily on construction of Sur de Texas, Villa de Reyes and Tula.

NATURAL GAS PIPELINES – BUSINESS RISKS

The following are risks specific to our natural gas pipelines business. See page 83 for information about general risks that affect the company as a whole, including other operational risks, HSE risks and financial risks.

Production levels within supply basins

Our pipelines downstream of the NGTL System depend largely on supply from the WCSB. Our Columbia System and its connecting downstream pipes largely depend on Appalachian supply. We continue to monitor any changes in our customers' natural gas production plans and how these changes may impact our existing assets and new project schedules. There is competition amongst pipelines to connect to major basins. An overall decrease in production and/or competing demand for supply could reduce throughput on our connected pipelines that, in turn, could negatively impact overall revenues generated. The WCSB and Appalachian basins are two of the most prolific basins in North America and have considerable natural gas reserves, however, 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. Furthermore, as a regulated pipeline business, we can apply for approval with the regulator to set tolls consistent with the level of throughput expected on our pipelines.

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 and impact revenue. New markets created by LNG export facilities developed to access global natural gas demand can lead to increased revenue through higher utilization of existing facilities and/or demand for new infrastructure. 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 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 and is impacted 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 accepts depends on the overall demand for transportation service. A decrease in the level of demand for our pipeline transportation services could adversely 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 condition 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 adversely impact anticipated 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 or require additional capital investment. There is a risk of an adverse impact to income if these costs are not fully recoverable.

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

Construction and operations

Constructing and operating our pipelines to ensure transportation services are provided safely and reliably is essential to the success of our business. Interruptions in our pipeline operations impacting our throughput capacity 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, hiring third party inspectors during construction, operating prudently, monitoring our pipeline systems 24 hours a day every day, using risk-based preventive maintenance programs and making effective capital investments. We use pipeline inspection equipment to regularly check the integrity of our pipelines, and repair or replace sections whenever necessary. We also calibrate the meters regularly to ensure accuracy, and continuously maintain compression equipment to ensure safe and reliable operation.

Liquids Pipelines

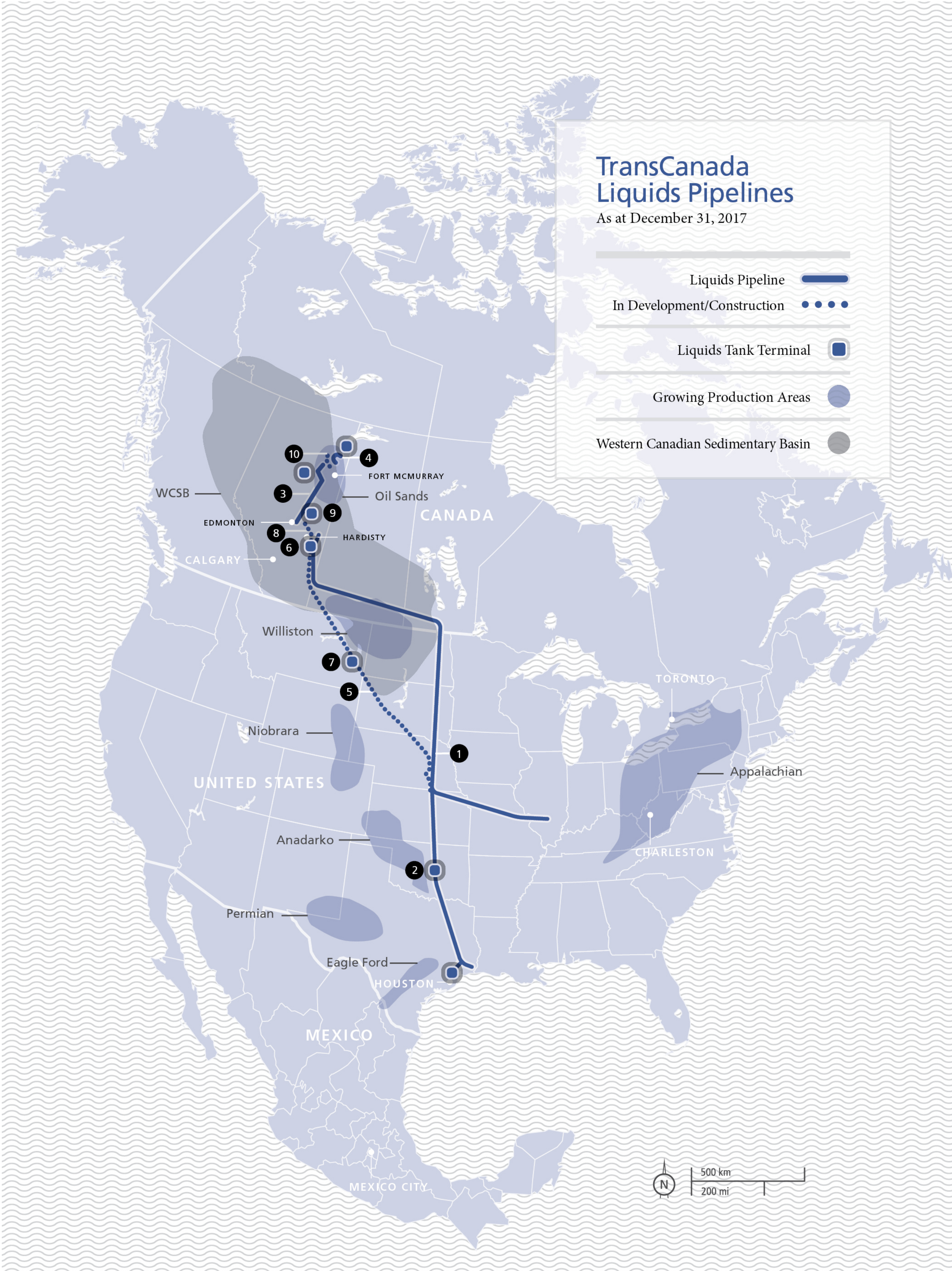
Our existing liquids pipelines infrastructure connects Alberta crude oil supplies to U.S. refining markets in Illinois, Oklahoma, Texas and the U.S. Gulf Coast. Our proposed future pipeline infrastructure would expand capacity for Canadian and U.S. crude oil to access key markets. We will also pursue enhancing our transportation service offerings to other areas of the liquids pipelines business value chain.

Strategy at a glance

- Focus on accessing and delivering growing North American liquids supply to key markets by expanding our liquids pipelines infrastructure to deliver directly from supply regions seamlessly along a contiguous path to market
- Focus on maximizing the value from our current operating assets, securing organic growth around these assets, identifying potential acquisition opportunities and positioning our business development activities to capture growth opportunities
- Expand transportation service offerings to other areas of the liquids pipelines business value chain including condensate transportation and ancillary services, such as short and long term storage of liquids, which complement our pipeline transportation infrastructure
- Continued development and construction of our proposed infrastructure projects to provide North America with a crucial liquids transportation network to transport growing supply directly to key markets and provide opportunities for us to further expand our liquids pipelines business.

Highlights

- Received the U.S. Presidential Permit for the Keystone XL project
- Received approval for a Nebraska pipeline route and secured sufficient commercial support to commence construction preparation for the Keystone XL project
- Secured incremental long-term contractual support following the conclusion of Keystone pipeline and Marketlink open seasons
- Informed the NEB that we will not be proceeding with the Energy East and Eastern Mainline project applications
- Completed construction of Grand Rapids and Northern Courier, two new intra-Alberta liquids pipelines



TransCanada
Liquids Pipelines
As at December 31, 2017
Liquids Pipeline
In Development/Construction
Liquids Tank Terminal
Growing Production Areas
Western Canadian Sedimentary Basin
10
4
FORT MCMURRAY
WCSB
3
Oil Sands
9
CANADA
EDMONTON
8
HARDISTY
6
CALGARY
Williston
7
5
TORONTO
Niobrara
1
Appalachian
UNITED STATES
Anadarko
CHARLESTON
2
Permian
Eagle Ford
HOUSTON
MEXICO
MEXICO CITY
N
500 km
200 mi

We are the operator and developer of the following:

		Length	Description	Ownership
	Liquids pipelines			
1	Keystone Pipeline System	4,324 km (2,687 miles)	Transports crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka, Illinois, Cushing, Oklahoma, and the U.S. Gulf Coast.	100%
2	Marketlink		Terminal and pipeline facilities to transport crude oil from the market hub at Cushing, Oklahoma to the U.S. Gulf Coast refining markets on facilities that form part of the Keystone Pipeline System.	100%
3	Grand Rapids	460 km (287 miles)	Transports crude oil from the producing area northwest of Fort McMurray, Alberta to the Edmonton/Heartland, Alberta market region.	50%
4	Northern Courier	90 km (56 miles)	Transports bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta.	100%
	In development			
5	Keystone XL	1,906 km (1,184 miles)	To transport crude oil from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System.	100%
6	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%
7	Bakken Marketlink		To transport crude oil from the Williston Basin producing region in North Dakota and Montana to Cushing, Oklahoma and the U.S. Gulf Coast on facilities that form part of the Keystone Pipeline System.	100%
8 9	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%
10	White Spruce	72 km (45 miles)	To transport crude oil from the Canadian Natural Resources Limited's Horizon facility in northeast Alberta into the Grand Rapids pipeline.	100%

UNDERSTANDING OUR LIQUIDS PIPELINES BUSINESS

Our liquids pipelines business primarily consists of pipelines, which efficiently move crude oil from major supply sources to markets where crude oil can be refined into various petroleum products, and ancillary services such as short and long term storage of liquids at terminals to optimize the value of our assets and expand into other areas of the liquids business value chain.

The Keystone Pipeline System, our largest liquids pipelines asset, moves approximately 20 per cent of western Canadian crude oil exports to key refining markets in the U.S. Midwest and the U.S. Gulf Coast. The Grand Rapids and Northern Courier pipelines, two new intra-Alberta liquids pipelines, are recent additions to our portfolio. Both greenfield pipelines provide transportation solutions for producers in northern and western Athabasca regions.

We provide pipeline capacity to shippers supported by long-term contracts with fixed monthly payments that are not linked to actual throughput volumes or to the price of the commodity, generating stable earnings over the contract term. Uncontracted capacity is periodically offered to the market to secure additional contracts or offered to the market on a spot basis which provides opportunities to generate incremental earnings. Storage of liquids is offered to our customers in return for fixed fee payments, which are not linked to actual storage volumes or to the price of the commodity.

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

Our liquids marketing business provides customers with a variety of crude oil marketing services including transportation, storage, and crude oil supply, primarily transacted through the purchase and sale of physical crude oil. In order to provide these services, TransCanada Liquids Marketing (TCLM) holds contractual rights on TransCanada and third-party owned pipelines and tank terminals. TCLM currently captures value in the market based on locational and time differentials.

Business environment

Crude oil continues to drive the modern economy, with people’s need for efficient and reliable transportation and products developed from petroleum generating the majority of global crude oil demand. Despite the emergence of new technologies that have made vehicles more fuel efficient, the International Energy Agency projects annual global crude oil demand growth will increase from 94 million Bbl/d in 2016 to 105 million Bbl/d in 2040 driven primarily by growth in Asia and developing countries.

The impact of recent OPEC crude oil production cuts has stabilized global prices, following the severe downturn that began in 2014. Global crude oil inventories are decreasing and are expected to continue to decline. A key driver to near and medium term crude oil pricing going forward will be the production decisions made by OPEC and some non-OPEC producers. Crude oil supply and demand is expected to balance in the near to medium term, as these producing countries extend their current production cuts through 2018. As the market comes into balance, crude oil prices are expected to recover to a range which will support further investment and supply growth.

Our liquids pipelines business is well positioned to endure the impact of short-term commodity price fluctuations and supply adjustments. 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, irrespective of commodity prices or throughput. The cyclical supply and demand nature of commodities and their 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 rate of project growth in our industry, the value of our services as contracts expire, and the timing for the demand of transportation services and/or new liquids infrastructure.

Supply and demand outlook

Canada

Canada has the world's third largest crude oil reserves and has the potential to increase its position as a major world supplier as crude oil production from mature oil fields around the world declines. 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 2017 Crude Oil Forecast, Markets and Transportation report, the Canadian Association of Petroleum Producers (CAPP) estimates 2018 WCSB crude oil supply will reach 0.8 million Bbl/d of conventional crude oil and condensate and 3.7 million Bbl/d of oil sands crude oil for a total of approximately 4.5 million Bbl/d, an increase of 0.3 million Bbl/d from 2017 levels. The report also forecasts WCSB crude oil supply will increase to 5.0 million Bbl/d by 2025 and to 5.5 million Bbl/d by 2030.

According to the 2017 Alberta's Energy Reserves and Supply/Demand Outlook, the AER estimates there was approximately 165 billion barrels of economically and technically recoverable conventional and oil sands reserves in Alberta in 2016. Oil sands projects have a long reserve life with steady production after initial ramp up. In its 2014 Responsible Canadian Energy report, CAPP estimates a typical oil sands mine has a 25 to 50-year lifespan, while an in-situ operation will run ten to 15 years on average. This longevity aligns with the producer's desire to secure long term market access for their reserves. The Keystone Pipeline System, Grand Rapids and Northern Courier are all underpinned by long term contracts.

U.S.

The U.S. is among the world's largest crude oil producers, with average production estimated at over 9.3 million Bbl/d in 2017 as a result of significant growth in light tight oil (LTO) production over the last five years. The U.S. EIA forecasts 1.4 million Bbl/d of U.S. production growth from 2017 to 2029, peaking at 10.5 million Bbl/d by 2029. It also forecasts U.S. production to average 10.3 million Bbl/d in 2018, which would mark the highest annual average production in U.S. history, surpassing the previous record of 9.6 million Bbl/d set in 1970.

Most continental U.S. crude oil is produced from the Williston, Eagle Ford, Niobrara, Permian, Anadarko and Appalachian production areas which represent some of the sources of crude oil supply for our Marketlink system at Cushing, Oklahoma. The Marketlink system, with connectivity to the Houston and Port Arthur, Texas and Lake Charles, Louisiana refining markets, is well positioned to transport this growing supply.

The U.S. is the world's largest crude oil consumer. U.S. crude oil demand is forecasted to grow slightly from approximately 16 million Bbl/d to over 17 million Bbl/d by 2040. U.S. Gulf Coast refineries are mainly configured to process heavy and medium crude oil and cannot easily switch to processing LTO in large quantities without significant capital investments. U.S. Gulf Coast refineries currently require approximately 8.6 million Bbl/d of crude oil, of which approximately 3.2 million Bbl/d is heavy and medium supplied primarily by offshore imports. This level of heavy demand is not expected to change significantly in the near or longer term. Our assets are well positioned to deliver Canadian crude oil to this significant market.

Strategic priorities

We remain committed to advancing our portfolio of commercially secured projects to connect growing Canadian and U.S. crude oil supply to key markets, maximizing the value from our existing assets, leveraging existing infrastructure and seeking new opportunities across the liquids pipelines value chain.

In 2017, we made significant progress on our Keystone XL project, which included receiving the U.S. Presidential Permit, approval of a route through Nebraska and securing sufficient commercial support. We have commenced construction preparation and primary construction execution is expected to begin in 2019. Completing the Keystone XL project will be a significant focus in order to augment and expand the Keystone Pipeline System's access in the U.S. Gulf Coast and connect to over 4.3 million Bbl/d of regional refinery capacity in Houston and Port Arthur, Texas and Lake Charles, Louisiana. Expanding the pipeline's market reach is expected to enhance both short and long haul volumes.

Within Alberta, we leveraged our extensive natural gas pipeline footprint and experience to develop an intra-Alberta liquids pipelines business. Resilient growth in oil sands production continues to support the need for intra-Alberta pipelines, such as our recently commissioned, 50 per cent owned, Grand Rapids pipeline that moves crude oil from northwest of Fort McMurray, Alberta to the market hub at Edmonton, Alberta, making it the first major pipeline completed in the west Athabasca region. Our joint venture between Grand Rapids and Keyera Corp. enhances our ability to access a reliable and cost effective source of diluent. The White Spruce pipeline will transport crude oil from Canadian Natural Resources Limited's Horizon facility into Grand Rapids and will further expand our regional footprint. In addition, our recently commissioned Northern Courier pipeline will facilitate supply from the Fort Hills Energy Partners' mine to market. With additional commercial support, the Heartland pipeline, TC Terminals and Keystone Hardisty Terminal projects, which have received regulatory approval, will allow shippers to seamlessly connect with the Keystone Pipeline System and other pipelines that transport crude oil outside of Alberta, and ultimately provide our customers with a contiguous path from production to market.

We will closely monitor the market place for strategic asset acquisitions to enhance our system connectivity or expand our footprint within North America. We remain disciplined in our approach and will position our business development activities strategically to capture opportunities as the business environment recovers.

SIGNIFICANT EVENTS

Keystone Pipeline System

In the fourth quarter of 2017, we concluded open seasons for Keystone pipeline and Marketlink and secured incremental long-term contractual support.

On November 16, 2017, the Keystone pipeline was temporarily shut down after a leak was detected in Marshall County, South Dakota. The estimated volume of the release was 5,000 barrels as reported to the National Response Center and the Pipeline and Hazardous Materials Safety Administration (PHMSA). On November 29, 2017, the pipeline was repaired and returned to service at a reduced pressure in the affected section of the pipeline. Further investigative activities and corrective measures required by PHMSA are planned for 2018.

This shutdown did not have a significant impact on our 2017 earnings.

Keystone XL

In February 2017, we filed an application with the Nebraska Public Service Commission (PSC) seeking approval for the Keystone XL pipeline route through that state and received approval for an alternate route on November 20, 2017. On November 24, 2017, we filed a motion with the Nebraska PSC to reconsider its ruling and permit us to file an amended application that would support their decision and would address certain issues related to their selection of the alternative route. On December 19, 2017, the Nebraska PSC denied this motion. On December 27, 2017, opponents of the Keystone XL project, and intervenors in the Keystone XL Nebraska regulatory proceeding, filed an appeal of the November 20, 2017 PSC decision seeking to have that decision overturned. TransCanada supports the decision of the Nebraska PSC and will actively participate in the appeal process to defend that decision.

In March 2017, the U.S. Department of State issued a U.S. Presidential Permit authorizing construction of the U.S./Canada border crossing facilities of the Keystone XL project. We discontinued our claim under Chapter 11 of the North American Free Trade Agreement and withdrew the U.S. Constitutional challenge. Later in March 2017, two lawsuits were filed in Montana District Court challenging the validity of the Presidential Permit. Along with the U.S. Government, we filed motions for dismissal of these law suits which were denied on November 22, 2017. The cases will now proceed to the consideration of summary judgment motions.

In July 2017, we launched an open season to solicit additional binding commitments from interested parties for transportation of crude oil on the Keystone pipeline and for the Keystone XL project from Hardisty, Alberta to Cushing, Oklahoma and the U.S. Gulf Coast. The successful open season concluded on October 26, 2017.

In January 2018, we secured sufficient commercial support to commence construction preparation for the Keystone XL project. We expect to commence primary construction in 2019 and construction will take approximately two years to complete.

Energy East

In September 2017, we requested the NEB suspend the review of the Energy East and Eastern Mainline project applications for 30 days to provide time for us to conduct a careful review of the NEB's changes, announced on August 23, 2017, regarding the list of issues and environmental assessment factors related to the projects and how these changes impact the projects' costs, schedules and viability.

In October 2017, after careful review of the changed circumstances, we informed the NEB that we would not be proceeding with the Energy East and Eastern Mainline project applications. We also notified Québec’s Ministère du Developpement durable, de l’Environnement, et de la Lutte contre les changements climatiques that we were withdrawing the Energy East project from the environmental review process. As the Energy East pipeline was also to provide transportation services for the Upland pipeline, the U.S. Department of State was notified in October 2017 that we would no longer be pursuing the U.S. Presidential Permit application for that project.

We reviewed the carrying value of the projects, including AFUDC capitalized since inception, and recorded a pre-tax, non-cash charge of $1,256 million ($954 million after-tax) in fourth quarter 2017. We ceased capitalizing AFUDC on the projects effective August 23, 2017, the date of the NEB's announced scope changes. With Energy East’s inability to reach a regulatory decision, no recoveries of costs from third parties are forthcoming.

Grand Rapids

In late August 2017, the Grand Rapids pipeline, jointly owned by TransCanada and PetroChina Canada Ltd., was placed in service. The 460 km (287 mile) crude oil transportation system connects producing areas northwest of Fort McMurray, Alberta to terminals in the Edmonton/Heartland region.

Northern Courier

In November 2017, the Northern Courier pipeline, a 90 km (56 mile) pipeline system which transports bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta, achieved commercial in-service.

White Spruce

In first quarter 2018, we anticipate receiving a decision from the AER on the regulatory permit to construct the $200 million White Spruce pipeline, which will transport crude oil from Canadian Natural Resources Limited's Horizon facility in northeast Alberta to the Grand Rapids pipeline. Due to the delay in the regulatory process, we expect the White Spruce pipeline to be in-service in 2019.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 and 2015 results have been adjusted to reflect this change.

year ended December 31 (millions of $)	**2017**	**2016**	**2015**
Keystone Pipeline System	**1,283**	1,155	1,332
Intra-Alberta pipelines	**33**	—	—
Other services[1]	**32**	(3)	(24)
Comparable EBITDA	**1,348**	1,152	1,308
Depreciation and amortization	**(309)**	(292)	(283)
Comparable EBIT	**1,039**	860	1,025
Specific items:			
Energy East impairment charge	**(1,256)**	—	—
Keystone XL asset costs	**(34)**	(52)	—
Keystone XL impairment charge	**—**	—	(3,686)
Risk management activities	**—**	(2)	—
Segmented (losses)/earnings	**(251)**	806	(2,661)
Comparable EBIT denominated as follows:			
Canadian dollars	**255**	223	227
U.S. dollars	**604**	482	623
Foreign exchange impact	**180**	155	175
Comparable EBIT	**1,039**	860	1,025

1 Includes primarily liquids marketing and business development activities.

Liquids Pipelines segmented earnings were $1,057 million lower in 2017 compared to 2016 and $3,467 million higher in 2016 than 2015.

Segmented losses in 2017 included a $1,256 million pre-tax impairment charge for the Energy East pipeline and $34 million (2016 - $52 million) of pre-tax costs related to Keystone XL for the maintenance and liquidation of project assets which were expensed pending further advancement of the project. Segmented earnings in 2016 also included unrealized losses from changes in the fair value of derivatives related to our liquids marketing business. Segmented losses in 2015 included a $3,686 million pre-tax impairment charge related to Keystone XL and related projects. See Critical accounting estimates on page 91 for more information. These amounts have been excluded from our calculation of comparable EBIT. The remainder of the Liquids Pipelines segmented earnings are equivalent to comparable EBIT, which, along with comparable EBITDA, are discussed below.

Comparable EBITDA for Liquids Pipelines was $196 million higher in 2017 compared to 2016 primarily due to the net effect of:

- higher uncontracted volumes on the Keystone Pipeline System
- a higher contribution from the liquids marketing business
- new intra-Alberta pipelines, Grand Rapids and Northern Courier, which began operations in the second half of 2017
- higher business development activities, including advancement of Keystone XL
- a weaker U.S. dollar which had a negative impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

Comparable EBITDA for Liquids Pipelines was $156 million lower in 2016 than in 2015 primarily due to the net effect of:

- lower uncontracted volumes on Keystone pipeline
- lower volumes on Marketlink
- higher contracted volumes on Keystone pipeline
- a higher contribution from the liquids marketing business
- lower business development activities
- a stronger U.S. dollar which had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

Depreciation and amortization

Depreciation and amortization was $17 million higher in 2017 than in 2016 as a result of new facilities being placed in-service, partially offset by the effect of a weaker U.S. dollar. Depreciation and amortization was $9 million higher in 2016 than in 2015 mainly due to the effect of a stronger U.S. dollar.

OUTLOOK

Earnings

Our 2018 earnings, excluding specific items, are expected to be higher than 2017, primarily as a result of full year earnings from the Northern Courier and Grand Rapids pipelines and incremental long-term contracts on the Keystone Pipeline System.

Capital spending

We spent a total of $0.5 billion in 2017 for our Liquids Pipelines capital projects and expect to spend approximately $0.4 billion in 2018.

BUSINESS RISKS

The following are risks specific to our liquids pipelines business. See page 83 for information about general risks that affect TransCanada as a whole, including other operational risks, 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 revenue 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.

While the majority of the costs to operate the liquids pipelines are passed through to our shippers, a portion of our volume is transported under an all-in fixed toll structure where we are exposed to changing costs which may adversely impact our earnings.

Regulatory and government

Decisions by Canadian and U.S. regulators can have a significant impact on the approval, construction, operation, commercial 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. In conjunction with this, there are some individuals and interest groups that are expressing their opposition to crude oil production by lobbying against the construction of liquids pipelines. Changing environmental requirements or revisions to current regulatory process may adversely impact the timing or ability to obtain permit approvals for our liquids pipelines. We manage these risks by continuously monitoring regulatory and government 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.

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 crude oil prices could mean producers may curtail their investment in the further development of crude oil supplies. Depending on the severity, these factors would negatively impact opportunities to expand our liquids pipelines 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 connect growing crude oil and condensate supplies between key North American producing regions and refining and export markets, we face competition from other midstream companies which also seek to transport these crude oil and condensate supplies to the same markets. Our success is dependent on our ability to offer and contract transportation services on terms that are market competitive.

Liquids marketing

Our liquids marketing business provides customers with a variety of crude oil marketing services including transportation, storage, and crude oil supply, primarily transacted through the purchase and sale of physical crude oil. Volatility in commodity prices and changing market conditions could adversely impact the value of those capacity contracts. Availability of alternative pipeline systems that can deliver into the same areas can also impact contract value. The liquids marketing business complies with our risk management policies which are described in Other information – Risks and risk management.

Energy

Our Energy business consists of power generation and unregulated natural gas storage assets.

The power business includes approximately 7,000 MW of generation capacity that we either own or are developing. Our power generation assets are located in Alberta, Ontario, Québec, New Brunswick and Arizona, and are powered by natural gas, nuclear, and wind. The majority of these assets are supported by long-term contracts.

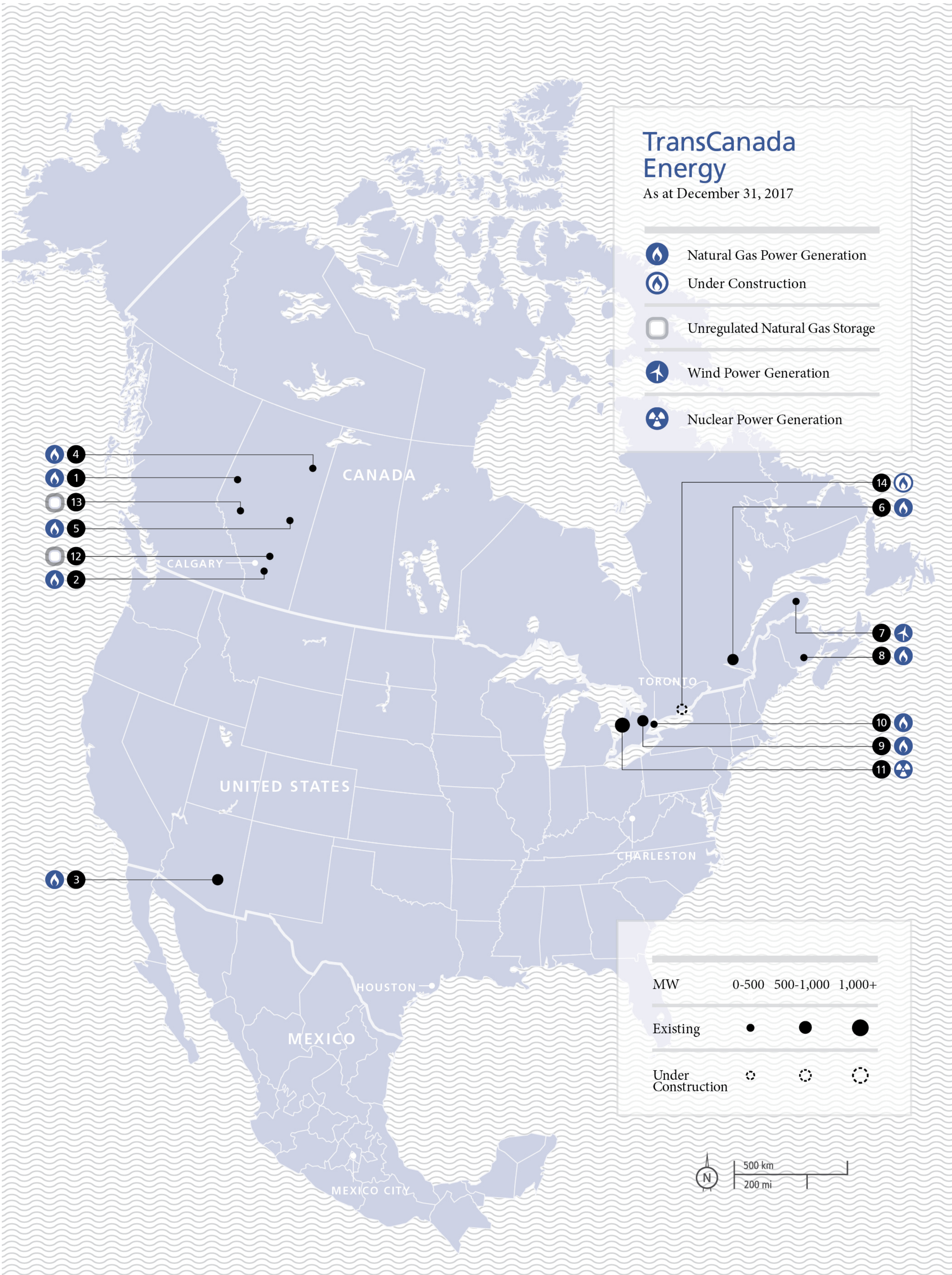
We own and operate approximately 118 Bcf of unregulated natural gas storage capacity in Alberta and hold a contract with a third party for additional storage, in total accounting for approximately one-third of all storage capacity in the province.

Strategy at a glance

- Maximize the value of our diverse portfolio of Energy assets through safe and reliable operations
- Execute capital programs on time and on budget
- Pursue North American growth in contracted power infrastructure as electric systems move to become less carbon intensive and absorb growing amounts of intermittent renewable capacity
- Maximize the value of our existing unregulated Alberta natural gas storage assets in an expanding gas marketplace that requires storage to balance and provide gas system reliability.

Highlights

- Strong financial results from Bruce Power; work is progressing on the life extension program
- Completed monetization of the U.S. Northeast generation assets and entered into an agreement to sell U.S. power retail contracts as part of the continued wind down of our U.S. power marketing operations
- Divestiture of Ontario solar assets to capture robust market value and provide capital to support near-term growth
- Construction continues on the 900 MW Napanee natural gas-fired power plant with expected in service in fourth quarter 2018.


TransCanada Energy
As at December 31, 2017
Natural Gas Power Generation
Under Construction
Unregulated Natural Gas Storage
Wind Power Generation
Nuclear Power Generation
CANADA
UNITED STATES
MEXICO
CALGARY
TORONTO
CHARLESTON
HOUSTON
MEXICO CITY
1
2
3
4
5
6
7
8
9
10
11
12
13
14
MW
0-500
500-1,000
1,000+
Existing
Under Construction
N
500 km
200 mi

We are the operator of all of our Energy assets, except for Cartier Wind, Bruce Power and Portlands Energy.

		Generating capacity (MW)	Type of fuel	Description	Ownership
	Canadian Power 6,983 MW of power generation capacity (including facilities under construction)				
	Western Power 1,021 MW of power generation capacity in Alberta and Arizona				
1	Bear Creek	100	natural gas	Cogeneration plant in Grande Prairie, Alberta.	100%
2	Carseland	95	natural gas	Cogeneration plant in Carseland, Alberta.	100%
3	Coolidge	575	natural gas	Simple-cycle peaking facility in Coolidge, Arizona. Power sold under a 20-year PPA with the Salt River Project Agricultural Improvements & Power District which expires in 2031.	100%
4	Mackay River	205	natural gas	Cogeneration plant in Fort McMurray, Alberta.	100%
5	Redwater	46	natural gas	Cogeneration plant in Redwater, Alberta.	100%
	Eastern Power 2,863 MW of power generation capacity (including facilities under construction)				
6	Bécancour	550	natural gas	Cogeneration plant in Trois-Rivières, Québec. Power sold under a 20-year PPA with Hydro-Québec which expires in 2026. Steam sold to an industrial customer. Power generation has been suspended since 2008. We continue to receive capacity payments while generation is suspended.	100%
7	Cartier Wind	365[1]	wind	Five wind power facilities in Gaspésie, Québec. Power sold under 20-year PPAs with Hydro-Québec which expire between 2026 and 2032.	62%
8	Grandview	90	natural gas	Cogeneration plant in Saint John, New Brunswick. Power sold under a 20-year tolling agreement for 100 per cent of heat and electricity output with Irving Oil which expires in 2024.	100%
9	Halton Hills	683	natural gas	Combined-cycle plant in Halton Hills, Ontario. Power sold under a 20-year Clean Energy Supply contract with the IESO which expires in 2030.	100%
10	Portlands Energy	275[1]	natural gas	Combined-cycle plant in Toronto, Ontario. Power sold under a 20-year Clean Energy Supply contract with the IESO which expires in 2029.	50%
	Bruce Power 3,099 MW of power generation capacity				
11	Bruce Power	3,099[1]	nuclear	Eight operating reactors in Tiverton, Ontario. Bruce Power leases the eight nuclear facilities from OPG.	48.4%
	Unregulated natural gas storage 118 Bcf of non-regulated natural gas storage capacity				
12	Crossfield	68 Bcf		Underground facility connected to the NGTL System in Crossfield, Alberta.	100%
13	Edson	50 Bcf		Underground facility connected to the NGTL System near Edson, Alberta.	100%
	Under construction				
14	Napanee	900	natural gas	Combined-cycle plant in Greater Napanee, Ontario. Power sold under a 20-year Clean Energy Supply contract with the IESO which expires 20 years from in-service date. Expected in-service date is fourth quarter 2018.	100%

1 Our share of power generation capacity.

UNDERSTANDING OUR ENERGY BUSINESS

Our Energy business is made up of two groups:

- Canadian Power
- Natural Gas Storage (Canadian, non-regulated).

Our U.S. Northeast Power generation assets were sold in second quarter 2017 and we are continuing to wind down our U.S. power marketing operations. See Significant Events section for more details.

Canadian Power

Western Power

We own approximately 1,000 MW of power supply through four natural gas-fired cogeneration facilities in Alberta and the Coolidge natural gas peaking facility in Arizona.

A disciplined operational strategy is critical to maximizing revenue at our cogeneration facilities and maximizing Coolidge earnings, where revenue is based on plant availability rather than a function of market price.

Our marketing group sells uncommitted power from the Alberta cogeneration plants, and buys and sells power and natural gas to maximize earnings from these assets. To reduce exposure associated with uncontracted power, 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 Government of Alberta has implemented a process to procure additional renewable energy in the coming years along with adding a capacity market in 2021 to the current energy-only market design of the Alberta power market. We continue to monitor and participate in the industry and Government discussions on the Alberta power market to identify the impacts to our existing cogeneration facilities and opportunities for potential growth.

Eastern Power

We own or are constructing approximately 2,900 MW of power generation capacity in Eastern Canada. All of the power produced by these assets is sold under long-term contracts.

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

Bruce Power

Bruce Power is a nuclear power generation facility located near Tiverton, Ontario and is comprised of eight nuclear units with a combined capacity of approximately 6,400 MW. Bruce Power leases the eight nuclear facilities from OPG. We hold a 48.4 per cent ownership interest in Bruce Power.

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

In 2015, Bruce Power entered into an agreement with the IESO to extend the operating life of the Bruce Power facility to 2064. This new agreement represents an extension and material amendment to the earlier agreement that led to the refurbishment of Units 1 and 2 at the site.

Under the amended agreement, which took economic effect in January 2016, Bruce Power has begun investing in life extension activities for Units 3 through 8 to support the long-term refurbishment program. This early investment in the Asset Management program is designed to result in near-term life extension up to the planned major refurbishment outages and beyond. Major Component Replacement (MCR) planning work is currently underway with the first MCR outage on Unit 6 expected in early 2020 and refurbishment of the remaining units planned to continue through 2033.

As part of the life extension and refurbishment agreement, Bruce Power receives a uniform contract price for all units which includes certain flow-through items such as fuel and lease expense recovery. 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 contract price.

Our estimated share of investment related to the Asset Management program to be completed over the life of the agreement is approximately $2.5 billion (2014 dollars). Our estimated share of investment in the MCR work for Units 3 through 8 over the 2020 to 2033 timeframe is approximately a further $4 billion (2014 dollars).

Under certain conditions, Bruce Power and the IESO can elect to not proceed with the remaining MCR investments should the cost exceed certain thresholds or prove to not provide sufficient economic benefits.

Over time, the contract price will be subject to adjustments for the return of and on capital invested at Bruce Power under the Asset Management and MCR capital programs, along with various other pricing adjustments that allow for a better matching of revenues and costs over the long term. As part of the amended agreement, Bruce Power is also required to share operating efficiencies with the IESO for better than planned performance.

Bruce Power also markets and trades power in Ontario and neighbouring jurisdictions under strict risk controls.

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 our regulated storage businesses. We also hold a contract for additional 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 natural gas storage business contracts with third parties, typically participants in the Alberta and interconnected gas markets, for a fixed fee to provide natural 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 natural gas prices.

SIGNIFICANT EVENTS

Canadian Power

Ontario Solar

On October 24, 2017, we entered into an agreement to sell our Ontario solar assets comprised of eight facilities with a total generating capacity of 76 MW. On December 19, 2017, we closed the sale for $541 million resulting in a pre-tax gain of $127 million ($136 million after tax).

Napanee

Construction continues on our 900 MW natural gas-fired power plant at OPG’s Lennox site in eastern Ontario in the town of Greater Napanee. We expect to invest approximately $1.3 billion in the Napanee facility and commercial operations are expected to begin in fourth quarter 2018. Costs have increased due to delays in the construction schedule. Once in service, production from the facility is fully contracted with the IESO for a 20-year period.

U.S. Power

Monetization of U.S. Northeast power business

In April 2017, we closed the sale of TC Hydro for US$1.07 billion, before post-closing adjustments and recorded a gain of approximately $715 million ($440 million after tax).

In June 2017, we closed the sale of Ravenswood, Ironwood, Ocean State Power and Kibby Wind for US$2.029 billion, before post-closing adjustments. In addition to pre-tax losses of approximately $829 million ($863 million after tax) that we recorded in 2016 upon entering into agreements to sell these assets, an additional pre-tax loss on sale of approximately $211 million ($167 million after tax) was recorded in 2017, primarily related to an adjustment to the purchase price and repair costs for an unplanned outage at Ravenswood prior to close, partially offset by insurance recoveries for a portion of the repair costs.

Proceeds from the sale transactions were used to fully retire the remaining bridge facilities that partially funded the acquisition of Columbia.

On December 22, 2017, we entered into an agreement to sell our U.S. power retail contracts as part of the continued wind down of our U.S. power marketing operations. The transaction is expected to close in the first quarter of 2018 subject to regulatory and other approvals.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 and 2015 results have been adjusted to reflect this change.

year ended December 31 (millions of $)	2017	2016	2015
Canadian Power			
Western Power[1]	**100**	74	71
Eastern Power	**344**	349	389
Bruce Power	**434**	293	285
Canadian Power – comparable EBITDA[1,2]	**878**	716	745
Depreciation and amortization	**(138)**	(145)	(193)
Canadian Power – comparable EBIT	**740**	571	552
U.S. Power – comparable EBITDA[3] (US$)	**100**	394	411
Depreciation and amortization[4]	**—**	(109)	(106)
U.S. Power – comparable EBIT (US$)	**100**	285	305
Foreign exchange impact	**30**	92	85
U.S. Power – comparable EBIT (Cdn$)	**130**	377	390
Natural Gas Storage and other operations – comparable EBITDA	**55**	58	14
Depreciation and amortization	**(13)**	(12)	(13)
Natural Gas Storage and other operations – comparable EBIT	**42**	46	1
Business Development and other costs – comparable EBITDA and EBIT[5]	**(33)**	(15)	(30)
Energy – comparable EBIT	**879**	979	913
Specific items:			
Gain/(loss) on sales of U.S. Northeast power assets	**484**	(844)	—
Gain on sale of Ontario solar assets	**127**	—	—
Ravenswood goodwill impairment	**—**	(1,085)	—
Alberta PPA terminations and settlement	**—**	(332)	—
Turbine equipment impairment charge	**—**	—	(59)
Bruce Power merger – debt retirement charge	**—**	—	(36)
Risk management activities	**62**	125	(37)
Segmented earnings/(loss)	**1,552**	(1,157)	781

1 Included losses from the Alberta PPAs up to March 2016 when the PPAs were terminated.
2 Includes our share of equity income from our investments in Portlands Energy and Bruce Power.
3 TC Hydro earnings included up to April 19, 2017 sale date; Ravenswood, Ironwood, Ocean State Power and Kibby Wind earnings included up to June 2, 2017 sale date.
4 Depreciation of U.S. Northeast power assets ceased effective November 2016 when classified as assets held for sale.
5 Includes a $21 million impairment charge in 2017 related to obsolete equipment.

Energy segmented earnings were $2,709 million higher in 2017 than in 2016 and $1,938 million lower in 2016 than in 2015 and included the following specific items:

- a net gain in 2017 of $484 million (2016 - loss of $844 million) before tax related to the monetization of our U.S. Northeast power assets which included a $715 million gain on the sale of TC Hydro, a loss of $211 million (2016 - $829 million) on the sale of the thermal and wind package and $20 million (2016 - $15 million) of pre-tax disposition costs. See Significant Events section for more details
- a gain in 2017 of $127 million before tax related to the sale of our Ontario solar assets. See Significant Events section for more details
- a $1,085 million impairment of Ravenswood goodwill in 2016. As a result of information received during the process to monetize our U.S. Northeast power business in third quarter 2016, it was determined that the fair value of Ravenswood no longer exceeded its carrying value
- a $332 million pre-tax charge in 2016 which included a $211 million impairment charge on the carrying value of our Alberta PPAs, a $29 million impairment of our equity investment in ASTC Power Partnership, and a $92 million loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the PPA terminations
- a loss in 2015 of $59 million before tax relating to an impairment in value of turbine equipment previously purchased for a power development project that did not proceed
- a charge in 2015 of $36 million before tax related to Bruce Power's retirement of debt in conjunction with the merger of the Bruce A and Bruce B partnerships
- 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)	**2017**	**2016**	**2015**
Canadian Power	**11**	4	(8)
U.S. Power	**39**	113	(30)
Natural Gas Storage	**12**	8	1
Total unrealized gains/(losses) from risk management activities	**62**	125	(37)

The variances in these unrealized gains and losses reflect the impact of changes in forward natural gas and power prices and the volume of our positions 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 representative 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.

Comparable EBITDA for Energy was $1,030 million in 2017 compared to $1,281 million in 2016, a decrease of $251 million, primarily due to the net effect of:

- lower earnings from U.S. Power due to the monetization of generating assets in second quarter 2017 and the wind down of our U.S. power marketing operations
- higher earnings from Bruce Power mainly due to higher volumes resulting from fewer outage days
- higher earnings from Western Power primarily due to the termination of the Alberta PPAs.

Comparable EBITDA for Energy was $1,281 million in 2016 compared to $1,254 million in 2015, an increase of $27 million, primarily due to the net effect of:

- higher earnings from Natural Gas Storage due to higher realized natural gas storage price spreads
- lower earnings from Eastern Power due to lower contractual earnings at Bécancour and lower contributions from the sale of unused natural gas transportation
- lower earnings from U.S. Power
- lower business development expenses primarily due to decreased business development activity
- higher earnings from Bruce Power mainly due to lower depreciation as a result of the operating life extensions, our increased ownership interest and higher realized sales price, partially offset by lower volumes and higher operating costs from increased outage days
- a stronger U.S. dollar and its positive effect on the foreign exchange impact.

Western and Eastern Power results

Western Power

Western Power comparable EBITDA in 2017 was $26 million higher than in 2016 mainly due to the termination of the Alberta PPAs. Results from the Alberta PPAs are included up to March 7, 2016 when we terminated the PPAs for the Sundance A, Sundance B and Sheerness facilities.

In 2016, Western Power comparable EBITDA was $3 million higher than in 2015 due to higher realized prices on generated volumes offset by PPA losses realized in first quarter 2016.

Eastern Power

Eastern Power comparable EBITDA in 2017 was $5 million lower than 2016 mainly due to lower earnings on the sale of unused natural gas transportation.

In 2016, Eastern Power comparable EBITDA was $40 million lower than 2015 due to lower contractual earnings at Bécancour and lower earnings on the sale of unused natural gas transportation.

Depreciation and amortization

Depreciation and amortization decreased by $7 million in 2017 compared to 2016 and $48 million in 2016 compared to 2015 following the termination of the Alberta PPAs in March 2016.

Bruce Power results

Bruce Power results reflect our proportionate share. Bruce A and B were merged in December 2015 and comparative information for 2015 is reported on a combined basis to reflect the merged entity. Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 8 for more information on non-GAAP measures we use. The following is our proportionate share of the components of comparable EBITDA and comparable EBIT.

year ended December 31 (millions of $, unless otherwise noted)	**2017**	**2016**	**2015**
Equity income included in comparable EBITDA and EBIT comprised of:			
Revenues	**1,626**	1,491	1,317
Operating expenses	**(846)**	(870)	(707)
Depreciation and other	**(346)**	(328)	(325)
Comparable EBITDA and comparable EBIT[1]	**434**	293	285
Bruce Power – other information			
Plant availability[2]	**90%**	83%	87%
Planned outage days	**221**	415	327
Unplanned outage days	**49**	76	45
Sales volumes (GWh)[1]	**24,368**	22,178	19,358
Realized sales price per MWh[3]	**$67**	$68	$66

1 Represents our 48.4 per cent (2016 - 48.5 per cent) ownership interest in Bruce Power after the merger on December 4, 2015 and, prior to this, 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. Comparable EBITDA in 2015 excludes a $36 million debt retirement charge.

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

3 Calculation based on actual and deemed generation. Realized sales price per MWh includes realized gains and losses from contracting activities and cost flow-through items. Excludes unrealized gains and losses on contracting activities and non-electricity revenues.

Bruce Power comparable EBITDA in 2017 was $141 million higher than 2016 mainly due to higher volumes resulting from fewer outage days.

In 2016, Bruce Power comparable EBITDA was $8 million higher than 2015 mainly due to lower depreciation as a result of the Bruce Power facility's operating life extension, our increased ownership and higher realized sales prices, partially offset by lower volumes and higher operating costs from increased outage days compared to 2015.

U.S. Power results

In second quarter 2017, we completed the sales of our U.S. Power generation assets and initiated the wind down of our U.S. power marketing operations. See Significant Events section for more details.

U.S. Power's comparable EBITDA in 2016 was US$17 million lower than 2015, primarily due to the net effect of:

- lower capacity revenues due to lower realized capacity prices in New York and the impact of lower availability as a result of a unit outage from September 2014 to May 2015, partially offset by insurance recoveries, net of deductibles at Ravenswood
- lower realized power prices and lower generation at our facilities in New England, partially offset by lower fuel costs
- lower margins on sales to wholesale, commercial and industrial customers partially offset by higher sales to customers in the PJM market
- higher earnings due to our acquisition of the Ironwood power plant in February 2016
- insurance recoveries related to an unplanned outage at the Ravenswood facility that occurred in 2008.

Natural Gas Storage and other operating results

Natural Gas Storage comparable EBITDA in 2017 was $3 million lower than 2016 primarily due to lower realized natural gas storage price spreads.

In 2016, Natural Gas Storage comparable EBITDA was $44 million higher than 2015 mainly due to higher realized natural gas storage price spreads.

OUTLOOK

Earnings

Our 2018 comparable earnings for the Energy segment are expected to be lower than 2017 primarily due to the monetization of the U.S. Northeast power generation assets in second quarter 2017 and the Ontario solar assets in late 2017, the continuing wind down of our U.S. Power marketing operations and higher planned outages at Bruce Power, partially offset by incremental earnings from the expected completion of the Napanee power plant in Ontario.

Following the monetization of the U.S. Northeast power business, the vast majority of Energy's remaining output is sold under long-term contracts.

Western Power earnings in 2018 are expected to be slightly higher than in 2017 due to an increase in forecast average spot power prices and a modest increase in generation.

Eastern Power earnings in 2018 are expected to be slightly lower than in 2017 due to the sale of our Ontario solar assets in 2017, partially offset by the completion of our Napanee power plant which is expected to begin commercial operations in fourth quarter 2018.

Bruce Power equity income in 2018 is expected to be lower than in 2017 due to higher planned outages. Planned maintenance is expected to occur on Bruce Units 1 and 4 in the first half of 2018 and Units 3 and 8 in the second half of 2018. The average plant availability percentage in 2018 is expected to be in the high 80 per cent range compared to 90 per cent in 2017.

Natural Gas Storage earnings in 2018 are expected to be lower than in 2017 due to lower expected realized storage spreads.

Capital spending

We spent a total of $0.4 billion in 2017 and expect to spend approximately $0.5 billion on capital projects in Energy in 2018, primarily on Napanee.

We invested $0.3 billion for capital and maintenance projects at Bruce Power in 2017 and expect to invest approximately $0.5 billion in 2018.

BUSINESS RISKS

The following are risks specific to our Energy business. See page 83 for information about general risks that affect the Company as a whole, including other operational risks, HSE risks, and financial risks.

Fluctuating power and natural gas market prices

Our portfolio of assets in Eastern Canada and our Coolidge facility in Arizona are fully contracted, and are therefore not materially impacted by fluctuating spot power and natural gas prices. As these contracts expire in the long term, it is uncertain if we will be able to re-contract on similar terms and may face future commodity exposure.

Much of the physical power generation and fuel used in our Western Power operations in Alberta is currently exposed to commodity price volatility. These exposures are mitigated through long-term contracts and hedging activities. As contracts expire, new contracts are entered into at prevailing market prices.

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

Plant availability

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

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

Regulatory

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

Compliance

Market rules, regulations and operating standards apply to our power business based on the jurisdictions in which they operate. Our trading and marketing activities may be subject to fair competition and market conduct requirements, as well as specific rules that apply to physical and financial transactions in deregulated markets. Similarly, our generators may be subject to specific operating and technical standards relating to maintenance activities, generator availability and delivery of energy and energy-related products. While significant efforts are made to ensure we comply with all applicable statutory requirements, situations including unforeseen operational challenges, lack of rule clarity, and the ambiguous and unpredictable application of requirements by regulators and market monitors occasionally arise and create compliance risk. Deemed contravention of these requirements may result in mandatory mitigation activities, monetary penalties, imposition of operational limitations, or even prosecution.

Weather

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

Competition

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

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented losses (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. Certain costs previously reported in our Corporate segment are now being reported within the business segments as a result of our 2015 business transformation initiative. 2016 and 2015 results have been adjusted to reflect this change.

year ended December 31 (millions of $)	**2017**	**2016**	**2015**
Comparable EBITDA and EBIT	**(21)**	18	(53)
Specific items:			
Integration and acquisition related costs – Columbia	**(81)**	(116)	—
Foreign exchange gain – inter-affiliate loan[1]	**63**	—	—
Restructuring costs	**—**	(22)	(99)
Segmented losses	**(39)**	(120)	(152)

1 Reported in Income from equity investments on the consolidated statement of income.

Corporate segmented losses were $81 million lower in 2017 compared to 2016 and $32 million lower in 2016 compared to 2015.

Segmented losses in 2017 included pre-tax integration and acquisition costs of $81 million (2016 – $116 million) associated with the acquisition of Columbia and a $63 million foreign exchange gain on a peso-denominated inter-affiliate loan to the Sur de Texas project for our proportionate share of the project's financing. There is a corresponding foreign exchange loss included in interest income and other on the inter-affiliate loan receivable which fully offsets this gain.

Segmented losses in 2016 and 2015 included restructuring costs of $22 million and $99 million, respectively, as described below. These amounts have been excluded from our calculation of comparable EBITDA and EBIT.

Comparable EBITDA decreased by $39 million in 2017 compared to 2016 primarily due to increased general and administrative costs.

Comparable EBITDA increased by $71 million in 2016 compared to 2015 primarily due to the 2015 inclusion of the portion of our corporate restructuring costs recovered through our tolling mechanisms.

Corporate restructuring and business transformation

In mid-2015, we commenced a business restructuring and transformation initiative to reduce overall costs and maximize the effectiveness and efficiency of our existing operations. As a result of this initiative, we began to incur restructuring costs, consisting primarily of severance and expected future losses under lease commitments, and recorded a provision of $87 million before tax to allow for planned severance costs for 2016 and 2017, as well as expected future losses under lease commitments. In 2016 and 2017, we recorded additional provisions to reflect changes in our expected future losses under lease commitments. Changes in the restructuring liability were as follows:

(millions of $)	**Employee Severance**	**Lease Commitments**	**Total**
Restructuring liability as at December 31, 2015	60	27	87
Restructuring charges	—	44	44
Cash payments	(24)	(8)	(32)
Restructuring liability as at December 31, 2016	36	63	99
Restructuring charges	—	6	6
Cash payments	(27)	(16)	(43)
Restructuring Liability as at December 31, 2017	**9**	**53**	**62**

The remaining employee severance provision at December 31, 2017 is expected to be settled in early 2018.

Cumulatively to December 31, 2017, we have incurred costs, net of amounts recoverable through regulatory and tolling structures, of $86 million for employee severance and $38 million for lease commitments under this initiative.

OTHER INCOME STATEMENT ITEMS

Interest Expense

year ended December 31 (millions of $)	2017	2016	2015
Interest on long-term debt and junior subordinated notes			
Canadian dollar-denominated	**(494)**	(452)	(437)
U.S. dollar-denominated	**(1,269)**	(1,127)	(911)
Foreign exchange impact	**(379)**	(366)	(255)
	(2,142)	(1,945)	(1,603)
Other interest and amortization expense	**(99)**	(114)	(47)
Capitalized interest	**173**	176	280
Interest expense included in comparable earnings	**(2,068)**	(1,883)	(1,370)
Specific items:			
Integration and acquisition related costs – Columbia	**—**	(115)	—
Risk management activities	**(1)**	—	—
Interest expense	**(2,069)**	(1,998)	(1,370)

Interest expense in 2017 was $71 million higher than in 2016 primarily due to the net effect of:

- long-term debt and junior subordinated notes issuances in 2017 and 2016, partially offset by Canadian and U.S. dollar-denominated debt maturities. See the Financial condition section for further details on long-term debt
- debt assumed in the acquisition of Columbia on July 1, 2016
- lower amortization expense on debt issuance costs related to the Columbia acquisition bridge facilities, which were fully repaid in June 2017
- higher foreign exchange on interest expense related to higher levels of U.S. dollar-denominated debt
- the specific item of $115 million in 2016 included the dividend equivalent payments of $109 million on the subscription receipts issued to partially fund the Columbia acquisition and $6 million of other acquisition related costs.

Interest expense in 2016 was $628 million higher than 2015 mainly due to the net effect of:

- the specific item of $115 million in 2016 discussed above
- long-term debt issuances in 2016 and 2015, partially offset by Canadian and U.S. dollar-denominated debt maturities
- debt assumed in the acquisition of Columbia on July 1, 2016
- higher foreign exchange on interest expense related to a weaker Canadian dollar and higher levels of U.S. dollar-denominated debt
- amortization expense on debt issuance costs related to the Columbia acquisition bridge facilities
- higher carrying charges to shippers in 2016 on the net revenue variance for the Canadian Mainline
- lower capitalized interest on Keystone XL and related projects following the November 6, 2015 denial of a U.S. Presidential Permit, partially offset by higher capitalized interest on liquids projects, LNG projects and Napanee.

Allowance for funds used during construction

year ended December 31 (millions of $)	2017	2016	2015
Allowance for funds used during construction			
Canadian dollar-denominated	**174**	181	119
U.S. dollar-denominated	**259**	181	137
Foreign exchange impact	**74**	57	39
Allowance for funds used during construction	**507**	419	295

AFUDC increased by $88 million in 2017 compared to 2016, mainly due to continued investment in and higher rates on projects acquired as part of the 2016 Columbia acquisition, as well as continued investment in Mexico projects and the NGTL System, partially offset by the commercial in-service of Topolobampo, the completion of Mazatlán construction and our decision not to proceed with the Energy East Pipeline.

AFUDC in 2016, was $124 million higher than 2015 due to capital expenditures on our Mexico pipelines, Energy East and NGTL System expansion projects.

Interest income and other

year ended December 31 (millions of $)	2017	2016	2015
Interest income and other included in comparable earnings	**159**	71	(111)
Specific items:			
Integration and acquisition related costs – Columbia	**—**	6	—
Foreign exchange loss - inter-affiliate loan	**(63)**	—	—
Risk management activities	**88**	26	(21)
Interest income and other	**184**	103	(132)

In 2017, interest income and other was $81 million higher than 2016 due to the net effect of:

- higher unrealized gains on risk management activities in 2017 compared to 2016. These amounts have been excluded from comparable earnings
- recovery of $32 million related to carrying charges on Coastal GasLink project costs incurred and recognized on the termination of the PRGT project. See the Canadian Natural Gas Pipelines Significant events section for more information
- foreign exchange impact on the translation of foreign currency denominated working capital balances
- lower realized gains in 2017 compared to 2016 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- higher interest income along with a $63 million foreign exchange loss related to an inter-affiliate loan receivable from the Sur de Texas joint venture. The corresponding interest expense and foreign exchange gain are reflected in income from equity investments in the Mexico Natural Gas Pipelines and Corporate segments, respectively. Both currency-related amounts are excluded from comparable earnings.

In 2016, interest income and other was $235 million higher than 2015 due to the net effect of:

- realized gains in 2016 compared to realized losses in 2015 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- unrealized gains on risk management activities in 2016 compared to losses in 2015. These amounts have been excluded from comparable earnings
- foreign exchange impact on the translation of foreign currency denominated working capital
- interest income on the gross proceeds of the subscription receipts issued to partially fund the Columbia acquisition. These amounts have been excluded from comparable earnings.

Income tax expense

year ended December 31 (millions of $)	2017	2016	2015
Income tax expense included in comparable earnings	**(839)**	(841)	(903)
Specific items:			
U.S. Tax Reform adjustment	**804**	—	—
Energy East impairment charge	**302**	—	—
Integration and acquisition related costs – Columbia	**22**	10	—
Gain on sale of Ontario solar assets	**9**	—	—
Keystone XL income tax recoveries	**7**	28	—
Keystone XL asset costs	**6**	10	—
Net gain on sales of U.S. Northeast power assets	**(177)**	(29)	—
Ravenswood goodwill impairment	**—**	429	—
Alberta PPA terminations and settlement	**—**	88	—
Restructuring costs	**—**	6	25
TC Offshore loss on sale	**—**	1	39
Keystone XL impairment charge	**—**	—	795
Turbine equipment impairment charge	**—**	—	16
Bruce Power merger – debt retirement charge	**—**	—	9
Alberta corporate income tax rate increase	**—**	—	(34)
Risk management activities	**(45)**	(54)	19
Income tax recovery/(expense)	**89**	(352)	(34)

Income tax expense included in comparable earnings in 2017 remained consistent with 2016 and reflects the net impact of higher comparable earnings, changes in the proportion of income earned between Canadian and foreign jurisdictions and changes in flow-through taxes in regulatory operations.

Income tax expense included in comparable earnings decreased by $62 million in 2016 compared to 2015 mainly due to lower flow-through taxes in 2016 on Canadian regulated pipelines and changes in the proportion of income earned between Canadian and foreign jurisdictions, partially offset by higher pre-tax earnings in 2016 compared to 2015.

Net income attributable to non-controlling interests

year ended December 31 (millions of $)	2017	2016	2015
Net income attributable to non-controlling interests included in comparable earnings	**(238)**	(257)	(205)
Specific items:			
Acquisition related costs – Columbia	**—**	5	—
TC PipeLines, LP – Great Lakes impairment	**—**	—	199
Net income attributable to non-controlling interests	**(238)**	(252)	(6)

Net income attributable to non-controlling interests and net income attributable to non-controlling interests included in comparable earnings decreased by $14 million and $19 million, respectively, in 2017 compared to 2016 primarily due to our acquisition of the remaining outstanding publicly held common units of CPPL in February 2017.

In 2016, net income attributable to non-controlling interests increased by $246 million compared to 2015 due to the net effect of a $5 million charge in 2016 related to the non-controlling interests' portion of retention and severance expenses resulting from the Columbia acquisition and a US$199 million impairment charge recorded by TC PipeLines, LP in 2015 related to its equity investment in Great Lakes. Both of these items were excluded in the calculation of comparable earnings. On consolidation, we reversed the non-controlling interests' 72 per cent of this TC PipeLines, LP impairment charge, which was US$143 million or $199 million in Canadian dollars. TC PipeLines, LP's impairment charge was not recognized at the TransCanada consolidation level as a result of our lower carrying value of Great Lakes. See the Critical accounting estimates section for more information on our goodwill impairment testing.

In 2016, net income attributable to non-controlling interests included in comparable earnings increased by $52 million compared to 2015 primarily due to the acquisition of Columbia, which brought with it a non-controlling interest in CPPL. The sale of our 30 per cent direct interest in GTN in April 2015 and a 49.9 per cent interest in PNGTS in January 2016 to TC PipeLines, LP, along with the impact of a stronger U.S. dollar on the Canadian dollar equivalent earnings from TC PipeLines, LP also contributed to increased net income attributable to non-controlling interests year-over-year.

Preferred share dividends

year ended December 31 (millions of $)	2017	2016	2015
Preferred share dividends	**(160)**	(109)	(94)

Preferred share dividends declared in 2017 increased by $51 million compared to 2016 due to the issuance of Series 13 and Series 15 preferred shares in April 2016 and November 2016, respectively. See Financial condition section for more information.

Financial condition

We strive to maintain strong financial capacity and flexibility in all parts of the economic cycle. We rely on our operating cash flow to sustain our business, pay dividends and fund a portion of our growth. In addition, we access capital markets to meet our financing needs, manage our capital structure and to preserve our credit ratings. More information on how our credit ratings can impact our financing costs, liquidity and operations is available in our Annual Information Form available on SEDAR (www.sedar.com).

We believe we have the financial capacity to fund our existing capital program through predictable and growing cash flow from operations, access to capital markets (including through our ATM equity issuance programs, as appropriate), our DRP, portfolio management including proceeds we receive from TC PipeLines, LP in exchange for the drop down of natural gas pipeline assets, cash on hand and substantial committed credit facilities. The drop down of our U.S. natural gas pipeline assets into TC PipeLines, LP remains an important financing option for us as we execute our capital growth program, subject to actual funding needs, market conditions, the relative attractiveness of alternate capital sources, as well as the approvals of TC PipeLines, LP's Board of Directors and our Board of Directors (the Board).

Balance sheet analysis

Our total assets at December 31, 2017 were $86.1 billion compared to $88.1 billion at December 31, 2016. The decrease primarily reflects the sales of our U.S. Northeast power assets to repay bridge facilities drawn to complete the acquisition of Columbia in 2016, and the impairment of Energy East and related projects. These amounts were partially offset by continued capital investment.

At December 31, 2017, our total liabilities were $59.2 billion compared to $60.9 billion at December 31, 2016. The decrease mainly reflects a net reduction in long-term debt, primarily as a result of retirement of the remaining Columbia acquisition bridge facilities, partially offset by issuances of junior subordinated notes and increased notes payable.

At December 31, 2017, we no longer have common units subject to rescission or redemption, compared to $1.2 billion at December 31, 2016, as a result of the acquisition of the outstanding publicly held common units of CPPL and the expiration of rescission rights on common units of TC PipeLines, LP.

Our equity at December 31, 2017 was $26.9 billion compared to $26.0 billion at December 31, 2016. The increase is primarily due to common shares issued under our DRP and corporate ATM program, partially offset by the impact of a stronger Canadian dollar on the translation of our net investment in foreign operations.

Consolidated capital structure

The following table summarizes the components of our capital structure.

at December 31 (millions of $ – unless otherwise noted)	**2017**	**Percent of Total**	**2016**	**Percent of total**
Notes payable	**1,763**	**3 %**	774	1 %
Long-term debt, including current portion	**34,741**	**50 %**	40,150	57 %
Cash and cash equivalents	**(1,089)**	**(2)%**	(1,016)	(1)%
Debt	**35,415**	**51 %**	39,908	57 %
Junior subordinated notes	**7,007**	**10 %**	3,931	6 %
Preferred shares	**3,980**	**6 %**	3,980	6 %
Common shareholders' equity[1]	**22,911**	**33 %**	22,003	31 %
	69,313	**100 %**	69,822	100 %

1 Includes non-controlling interests.

At December 31, 2017, we had unused capacity of $2.8 billion, $2.0 billion, and US$7.5 billion under our various equity, Canadian debt and U.S. debt shelf prospectuses, respectively, to facilitate future access to capital markets.

We were in compliance with all of our financial covenants at December 31, 2017. Provisions of various trust indentures and credit arrangements with certain of our subsidiaries can restrict those subsidiaries' ability to declare and pay dividends or make distributions under certain circumstances. If such restrictions apply, they may, in turn, have an impact on our ability to declare and pay dividends on our common and preferred shares. In the opinion of management, these provisions do not currently restrict or alter our ability to declare or pay dividends. These trust indentures and credit arrangements also require us to comply with various affirmative and negative covenants and maintain certain financial ratios.

Cash flow

The following tables summarize the consolidated cash flows of our business.

year ended December 31 (millions of $)	2017	2016	2015
Net cash provided by operations	**5,230**	5,069	4,384
Net cash used in investing activities	**(3,699)**	(18,783)	(4,879)
	1,531	(13,714)	(495)
Net cash (used in)/provided by financing activities	**(1,419)**	14,007	744
	112	293	249
Effect of foreign exchange rate changes on cash and cash equivalents	**(39)**	(127)	112
Increase in cash and cash equivalents	**73**	166	361

At December 31, 2017, our current assets totaled $4.7 billion (2016 – $8.1 billion) and current liabilities amounted to $9.9 billion (2016 – $7.7 billion), leaving us with a working capital deficit of $5.2 billion compared to a surplus of $0.4 billion at December 31, 2016. The surplus at December 31, 2016 was primarily the result of the pending sale of the U.S. Northeast power assets, the $3.7 billion carrying value of which had been reclassified to assets held for sale within current assets. Without the assets held for sale classification as current on the balance sheet, we would have reported a working capital deficit at December 31, 2016. Our working capital deficiency is considered to be in the normal course of business and is managed through:

- our ability to generate predictable and growing cash flow from operations
- our access to capital markets, including through our DRP and ATM programs
- approximately $9.0 billion of unused, unsecured credit facilities.

Cash provided by operating activities

year ended December 31 (millions of $)	2017	2016	2015
Net cash provided by operations	**5,230**	5,069	4,384
Increase/(decrease) in operating working capital	**273**	(248)	346
Funds generated from operations	**5,503**	4,821	4,730
Specific items:			
Integration and acquisition related costs - Columbia	**84**	283	—
Keystone XL asset costs	**34**	52	—
U.S. Northeast power disposition costs	**20**	15	—
Restructuring costs	**—**	—	85
Comparable funds generated from operations	**5,641**	5,171	4,815
Dividends on preferred shares	**(155)**	(100)	(92)
Distributions paid to non-controlling interests	**(283)**	(279)	(224)
Maintenance capital expenditures including equity investments			
– Recoverable in future tolls	**(1,364)**	(941)	(786)
– Other	**(240)**	(310)	(256)
Comparable distributable cash flow			
– Reflecting all maintenance capital expenditures	**3,599**	3,541	3,457
– Reflecting only non-recoverable maintenance capital expenditures	**4,963**	4,482	4,243
Comparable distributable cash flow per common share			
– Reflecting all maintenance capital expenditures	**$4.13**	$4.67	$4.88
– Reflecting only non-recoverable maintenance capital expenditures	**$5.69**	$5.91	$5.98

Net cash provided by operations

The year-over-year increases in net cash provided by operations are primarily due to higher comparable earnings (as discussed in Financial highlights on page 21) and the amount and timing of working capital changes.

Comparable funds generated from operations

Comparable funds generated from operations, a non-GAAP measure, helps us assess the cash generating ability of our operations by excluding the timing effects of working capital changes. See page 8 for more information about non-GAAP measures.

Comparable funds generated from operations increased by $470 million in 2017 compared to 2016, primarily due to higher comparable EBITDA (excluding income from equity investments) and higher distributions from our equity investments, partially offset by higher interest expense and increased funding of our employee post-retirement benefit plans.

Comparable funds generated from operations increased by $356 million in 2016 compared to 2015 mainly due to higher comparable EBITDA (excluding income from equity investments) and higher interest income and other primarily due to realized gains in 2016 against losses in 2015 and higher distributions from our equity investments, partially offset by higher interest expense on debt incurred for and assumed in the Columbia acquisition, lower capitalized interest on Keystone XL and higher funding of our employee post-retirement benefit plans.

Comparable distributable cash flow

Comparable distributable cash flow, a non-GAAP measure, helps us assess the cash available to common shareholders before capital allocation. See page 8 for more information on non-GAAP measures we use.

The year-over-year increases in comparable distributable cash flow primarily reflect higher comparable funds generated from operations, as described above, partially offset by higher recoverable maintenance capital expenditures in Canadian and U.S. natural gas pipelines. Comparable distributable cash flow per common share for the year ended December 31, 2017 also includes the dilutive effect of common shares issued in 2016 and 2017.

Although we deduct maintenance capital expenditures in determining comparable distributable cash flow, we have the ability to recover the majority of these costs in Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Liquids Pipelines. Canadian natural gas pipelines maintenance capital expenditures are reflected in rate bases, on which we earn a regulated return and subsequently recover in tolls. Almost all of our U.S. natural gas pipelines can recover maintenance capital through tolls under current rate settlements, or have the ability to recover maintenance capital through tolls established in future rate cases or settlements. Tolling arrangements in Liquids Pipelines provide for recovery of maintenance capital.

The following table provides a breakdown of maintenance capital expenditures.

year ended December 31 (millions of $)	**2017**	**2016**	**2015**
Canadian Natural Gas Pipelines	**601**	323	347
U.S. Natural Gas Pipelines	**749**	586	381
Liquids Pipelines	**19**	32	58
Other	**235**	310	256
Maintenance capital expenditures including equity investments	**1,604**	1,251	1,042

Cash used in investing activities

year ended December 31 (millions of $)	2017	2016	2015
Capital spending			
Capital expenditures	**(7,383)**	(5,007)	(3,918)
Capital projects in development	**(146)**	(295)	(511)
Contributions to equity investments	**(1,681)**	(765)	(493)
	(9,210)	(6,067)	(4,922)
Acquisitions, net of cash acquired	**—**	(13,608)	(236)
Proceeds from sale of assets, net of transaction costs	**5,317**	6	—
Other distributions from equity investments	**362**	727	9
Deferred amounts and other	**(168)**	159	270
Net cash used in investing activities	**(3,699)**	(18,783)	(4,879)

Net cash used in investing activities decreased from $18.8 billion in 2016 to $3.7 billion in 2017 mainly due to the net effect of:

- the 2016 acquisitions of Columbia and Ironwood
- higher capital spending in 2017
- proceeds from the sales of our U.S. power generation assets and solar assets in 2017
- recovery of PRGT project costs.

Net cash used in investing activities increased from $4.9 billion in 2015 to $18.8 billion in 2016 primarily as a result of the acquisitions of Columbia and Ironwood along with higher capital spending, partially offset by increased distributions received from Bruce Power related to its debt issuances.

Capital Spending[1]

The following table summarizes capital spending by segment.

year ended December 31 (millions of $)	2017	2016	2015
Canadian Natural Gas Pipelines	**2,181**	1,525	1,596
U.S. Natural Gas Pipelines	**3,830**	1,522	537
Mexico Natural Gas Pipelines	**1,954**	1,142	566
Liquids Pipelines	**529**	1,137	1,601
Energy	**675**	708	558
Corporate	**41**	33	64
	9,210	6,067	4,922

1 Capital spending includes capacity capital expenditures, maintenance capital expenditures, capital projects in development, and contributions to equity investments.

Capital expenditures

Capital expenditures in 2017 were incurred primarily for the expansion of the Columbia Gas, Columbia Gulf, NGTL System and Canadian Mainline natural gas pipelines, the construction of Mexican natural gas pipelines and the Napanee power generating facility, as well as capital additions to and maintenance of our ANR pipeline.

Our 2016 capital expenditures were incurred mainly for expanding the Columbia Gas and Columbia Gulf pipelines from their acquisition date along with the NGTL System, Canadian Mainline and ANR, plus construction of our Mexican natural gas pipelines, Northern Courier pipeline and the Napanee power generating facility.

Our 2015 capital expenditures were incurred primarily for expanding the NGTL System, Canadian Mainline and ANR, plus construction of our Mexican natural gas pipelines, Northern Courier pipeline and the Napanee power generating facility.

Capital projects in development

Costs incurred on capital projects in development were predominantly related to spending on the Energy East and LNG-related pipeline projects in each year.

Contributions to equity investments

Contributions to equity investments increased in 2017 compared to 2016 primarily due to our investments in Sur de Texas, Bruce Power and Northern Border, partially offset by decreased contributions to Grand Rapids which went into service in August 2017. Contributions to equity investments in 2017 also includes our proportionate share of Sur de Texas debt financing.

The increase in contributions to equity investments in 2016 compared to 2015 was primarily due to our investments in Bruce Power, Grand Rapids and Sur de Texas.

Acquisitions and sales of assets

On December 19, 2017, we closed the sale of our Ontario solar assets for proceeds of approximately $541 million, before post-closing adjustments.

On July 25, 2017, we were notified that PNW LNG would not be proceeding with their LNG project. As a result, we received a payment of $0.6 billion from Progress Energy in October 2017 for full recovery of our costs plus carrying charges.

On June 2, 2017, TransCanada completed the sale of Ravenswood, Ironwood, Kibby Wind and Ocean State Power for proceeds of approximately US$2.029 billion, before post-closing adjustments.

On April 19, 2017, the Company completed the sale of TC Hydro for proceeds of approximately US$1.07 billion, before post-closing adjustments.

In 2016, we completed the following transactions:

- acquired 100 per cent ownership of Columbia for US$10.3 billion in cash
- acquired the Ironwood power plant for US$653 million in cash after post-acquisition adjustments
- acquired an additional 5.52 per cent interest in Iroquois for an aggregate purchase price of US$61 million
- sold TC Offshore for $6 million.

Other distributions from equity investments

Other distributions from equity investments primarily reflects our proportionate share of Bruce Power financings undertaken to fund its capital program and make distributions to its partners. In 2017, Bruce Power issued senior notes in capital markets which resulted in distributions totaling $362 million being received by us. In 2016, Bruce Power issued senior notes in the capital markets and borrowed under a bank credit facility which resulted in $725 million being received by us.

Cash (used in)/provided by financing activities

year ended December 31 (millions of $)	**2017**	**2016**	**2015**
Notes payable issued/(repaid), net	**1,038**	(329)	(1,382)
Long-term debt issued, net of issue costs	**3,643**	12,333	5,045
Long-term debt repaid	**(7,085)**	(7,153)	(2,105)
Junior subordinated notes issued, net of issue costs	**3,468**	1,549	917
Dividends and distributions paid	**(1,777)**	(1,815)	(1,762)
Common shares issued, net of issue costs	**274**	7,747	27
Common shares repurchased	**—**	(14)	(294)
Preferred shares issued, net of issue costs	**—**	1,474	243
Partnership units of subsidiary issued, net of issue costs	**225**	215	55
Common units of Columbia Pipelines Partners LP acquired	**(1,205)**	—	—
Net cash (used in)/provided by financing activities	**(1,419)**	14,007	744

Net cash provided by financing activities decreased by $15.4 billion in 2017 compared to 2016 primarily due to significant financing activity, including common share issuances, associated with funding the US$10.3 billion cash acquisition of Columbia in 2016 and the US$921 million acquisition of the outstanding publicly held common units of CPPL in 2017 which, as a transaction between entities under common control, was recorded in equity.

Net cash provided by financing activities increased by $13.3 billion in 2016 compared to 2015 mainly due to issuances of long-term debt (net of long-term debt repaid), common shares, junior subordinated notes and preferred shares in 2016 to support the financing of the Columbia acquisition.

The principal transactions reflected in our financing activities are discussed in further detail below.

Long-term debt issued

In 2017, TCPL issued US$700 million of Senior Unsecured Notes, bearing interest at a fixed rate of 2.125 per cent, as well as an additional US$550 million of Senior Unsecured Notes, bearing interest at a floating rate, due in November 2019.

In 2017, TCPL issued $700 million of Medium Term Notes, due in September 2047, bearing interest at a fixed rate of 4.33 per cent, as well as an additional $300 million of Medium Term Notes, due in March 2028, bearing interest at a fixed rate of 3.39 per cent.

The net proceeds of the above debt issuances were used for general corporate purposes, to fund our capital program and to repay existing debt.

In 2017, TC PipeLines, LP issued US$500 million of Senior Unsecured Notes, due in May 2027, bearing interest at a fixed rate of 3.90 per cent. The net proceeds of this debt issuance were primarily used to fund TC PipeLines, LP's acquisition of interests in PNGTS and Iroquois.

For more information about long-term debt issued in 2017, 2016 and 2015, see Note 17, Long-Term Debt, of our consolidated financial statements.

Long-term debt repaid

Proceeds from the sales of our U.S. Northeast power generation assets were used to repay US$3.7 billion of acquisition bridge facilities in 2017. The facilities were initially put into place to finance a portion of the Columbia acquisition.

In 2017, TCPL repaid US$1.0 billion of Senior Unsecured Notes bearing interest at a fixed rate of 1.625 per cent, $300 million of Medium Term Notes bearing interest at a fixed rate of 5.10 per cent and $100 million of Debentures bearing interest at a fixed rate of 9.80 per cent.

In 2018, TCPL repaid US$500 million of Senior Unsecured Notes bearing interest at a fixed rate of 1.875 per cent and US$250 million of Senior Unsecured Notes bearing interest at a floating rate.

For more information about long-term debt repaid in 2017, 2016 and 2015, see Note 17, Long-Term Debt, of our consolidated financial statements.

Junior subordinated notes issued

In May 2017, TransCanada Trust (Trust), a wholly-owned financing trust subsidiary of TCPL, issued $1.5 billion of Trust Notes – Series 2017-B to third party investors at a fixed interest rate of 4.65 per cent for the first ten years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for $1.5 billion of junior subordinated notes of TCPL at an initial fixed rate of 4.90 per cent, including a 0.25 per cent administration charge, for the first ten years, converting to a floating rate thereafter. The junior subordinated notes are redeemable at TCPL's option at any time on or after May 18, 2027 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

In March 2017, the Trust issued US$1.5 billion of Trust Notes – Series 2017-A to third party investors at a fixed interest rate of 5.30 per cent for the first ten years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for US$1.5 billion of junior subordinated notes of TCPL at an initial fixed rate of 5.55 per cent, including a 0.25 per cent administration charge, for the first ten years, converting to a floating rate thereafter. The junior subordinated notes are redeemable at TCPL's option at any time on or after March 15, 2027 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

Pursuant to the terms of the Trust Notes and related agreements, in certain circumstances (1) TCPL may issue deferral preferred shares to holders of the Trust Notes in lieu of interest; and (2) TransCanada and TCPL would be prohibited from declaring or paying dividends on or redeeming their outstanding preferred shares (or, if none are outstanding, their respective common shares) until all deferral preferred shares are redeemed by TCPL. The Trust Notes may also be automatically exchanged for preferred shares of TCPL upon certain kinds of bankruptcy and insolvency events. All of these preferred shares would rank equally with any other outstanding first preferred shares of TCPL.

For more information about the junior subordinated notes, see Note 18, Junior Subordinated Notes, of our consolidated financial statements.

Dividend reinvestment plan

On July 1, 2016, we re-initiated the issuance of common shares from treasury under our DRP. Under this plan, eligible holders of common and preferred shares of TransCanada can reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares. Common shares are issued from treasury at a discount of two per cent to market prices over a specified period. On dividends declared in 2017, the participation rate amongst common shareholders was approximately 36 per cent (2016 – 39 per cent), resulting in $791 million (2016 – $363 million) of common equity issued.

TransCanada Corporation ATM Issuance Program

In June 2017, we established an ATM program that allows us to issue common shares from treasury from time to time, at the prevailing market price, when sold through the Toronto Stock Exchange (TSX), the New York Stock Exchange (NYSE), or any other existing trading market for TransCanada common shares in Canada or the United States. The ATM program, which is effective for a 25-month period, will be utilized as appropriate to manage our capital structure over time. The program has an aggregate gross sales limit of $1.0 billion or the U.S. dollar equivalent. In 2017, 3.5 million common shares were issued under the program at an average price of $63.03 per share for gross proceeds of $218 million. Related commissions and fees totaled approximately $2 million, resulting in net proceeds of $216 million.

Common shares issued under public offerings and subscription receipts

In November 2016, we issued 60.2 million common shares at a price of $58.50 each for total proceeds of approximately $3.5 billion. Proceeds from the offering were used to repay a portion of the US$6.9 billion of acquisition bridge facilities which were used to partially fund the closing of the Columbia acquisition.

In April 2016, we issued 96.6 million subscription receipts entitling each holder to receive one common share upon closing of the Columbia acquisition to partially fund the Columbia acquisition at a price of $45.75 each for total proceeds of $4.4 billion. On July 1, 2016, these subscription receipts were automatically exchanged for TransCanada common shares in accordance with the terms of the subscription receipt agreement and were delisted from the TSX. Holders of record at close of business on April 15, 2016 and June 30, 2016 received a cash payment per subscription receipt that was equal in amount to dividends declared on each common share.

For more information about common shares and subscription receipts issued, including dividend equivalent payments, see Note 20, Common Shares, of our consolidated financial statements.

Common shares repurchased

In November 2015, we announced that the TSX had approved our normal course issuer bid (NCIB), which allowed for the repurchase and cancellation of up to 21.3 million of our common shares, representing three per cent of our issued and outstanding common shares. Under the NCIB, which expired in November 2016, we repurchased 7.1 million common shares at an average purchase price of $43.36 per share through the facilities of the TSX, other designated exchanges and published markets in Canada, or through off-exchange block purchases by way of private agreement.

Preferred share issuance, redemption and conversion

No preferred shares were issued in 2017.

In November 2016, we completed a public offering of 40 million Series 15 cumulative redeemable minimum rate reset first preferred shares at $25 per share resulting in gross proceeds of $1.0 billion. The Series 15 preferred shareholders will have the right to convert their Series 15 preferred shares into Series 16 cumulative redeemable first preferred shares on May 31, 2022 and on the last business day of May of every fifth year thereafter.

In April 2016, we completed a public offering of 20 million Series 13 cumulative redeemable minimum rate reset first preferred shares at $25 per share resulting in gross proceeds of $500 million. The Series 13 preferred shareholders will have the right to convert their Series 13 preferred shares into Series 14 cumulative redeemable first preferred shares on May 31, 2021 and on the last business day of May of every fifth year thereafter.

In February 2016, holders of 1.3 million Series 5 cumulative redeemable first preferred shares exercised their option to convert to Series 6 cumulative redeemable first preferred shares and receive quarterly floating rate cumulative dividends at an annual rate equal to the applicable 90-day Government of Canada treasury bill rate plus 1.54 per cent which will reset every quarter going forward. The fixed dividend rate on the remaining Series 5 preferred shares was reset for five years at 2.263 per cent per annum and will reset every five years going forward.

The net proceeds of the above preferred share offerings were used for general corporate purposes and to reduce short-term indebtedness which was used to fund our capital program.

For more information on preferred shares see Note 21, Preferred Shares, of our consolidated financial statements.

Common units of Columbia Pipeline Partners LP

On February 17, 2017, we acquired all outstanding publicly held common units of CPPL at a price of US$17.00 and a stub period distribution payment of US$0.10 per common unit for an aggregate transaction value of US$921 million. As this was a transaction between entities under common control, it was recognized in equity.

TC PipeLines, LP

At-the-market equity issuance program

Under the TC PipeLines, LP ATM program, TC PipeLines, LP is authorized, from time to time, to offer and sell common units through ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed upon by TC PipeLines, LP and by one or more of its agents. Our ownership interest in TC PipeLines, LP decreases as a result of equity issuances under the ATM program.

During 2017, 3.1 million (2016 – 3.1 million) common units were issued under the TC PipeLines, LP ATM program generating net proceeds of approximately US$173 million (2016 – US$164 million). At December 31, 2017, our ownership interest in TC PipeLines, LP was 25.7 per cent (2016 – 26.8 per cent) after issuances under the ATM program and resulting dilution.

In connection with the late filing of an employee-related Form 8-K with the SEC, in March 2016, TC PipeLines, LP became ineligible to use the then effective shelf registration statement upon the filing of its 2015 Annual Report. As a result, it was determined that the purchasers of 1.6 million common units issued from March 8, 2016 to May 19, 2016 under the ATM program may have had a rescission right for an amount equal to the purchase price paid for the units, plus statutory interest and less any distributions paid, upon the return of such units to TC PipeLines, LP. In 2017, all rescission rights expired and no unitholder claimed or attempted to exercise any rescission rights prior to the expiration date.

Asset drop downs

On June 1, 2017, we closed the sale of 49.34 per cent of our 50 per cent interest in Iroquois, along with an option to sell the remaining 0.66 per cent at a later date, to TC PipeLines, LP. At the same time, we closed the sale of our remaining 11.81 per cent interest in PNGTS to TC PipeLines, LP. Proceeds from these transactions were US$765 million before post-closing adjustments. Proceeds were comprised of US$597 million in cash and US$168 million representing a proportionate share of Iroquois and PNGTS debt.

In January 2016, we closed the sale of a 49.9 per cent interest in PNGTS to TC PipeLines, LP for US$223 million. Proceeds were comprised of US$188 million in cash and the assumption of US$35 million of a proportional share of PNGTS debt.

Share information

as at February 12, 2018		
Common Shares	**issued and outstanding**	
	885 million	
Preferred Shares	**issued and outstanding**	**convertible to**
Series 1	9.5 million	Series 2 preferred shares
Series 2	12.5 million	Series 1 preferred shares
Series 3	8.5 million	Series 4 preferred shares
Series 4	5.5 million	Series 3 preferred shares
Series 5	12.7 million	Series 6 preferred shares
Series 6	1.3 million	Series 5 preferred shares
Series 7	24 million	Series 8 preferred shares
Series 9	18 million	Series 10 preferred shares
Series 11	10 million	Series 12 preferred shares
Series 13	20 million	Series 14 preferred shares
Series 15	40 million	Series 16 preferred shares
Options to buy common shares	**outstanding**	**exercisable**
	11 million	7 million

For more information on preferred shares see Note 21, Preferred Shares, of our consolidated financial statements.

Dividends

year ended December 31	2017	2016	2015
Dividends declared			
per common share	**$2.50**	$2.26	$2.08
per Series 1 preferred share	**$0.8165**	$0.8165	$0.8165
per Series 2 preferred share	**$0.62138**	$0.60648	$0.6299
per Series 3 preferred share	**$0.538**	$0.538	$0.769
per Series 4 preferred share	**$0.46138**	$0.44648	$0.2269
per Series 5 preferred share	**$0.56575**	$0.56575	$1.10
per Series 6 preferred share	**$0.55275**	$0.50648	—
per Series 7 preferred share	**$1.00**	$1.00	$1.00
per Series 9 preferred share	**$1.0625**	$1.0625	$1.0625
per Series 11 preferred share	**$0.95**	$1.1875	$0.704
per Series 13 preferred share	**$1.375**	$1.18525	—
per Series 15 preferred share	**$1.225**	$0.3323	—

Credit facilities

We have several committed credit facilities that support our commercial paper programs and provide short-term liquidity for general corporate purposes. In addition, we have demand credit facilities that are also used for general corporate purposes, including issuing letters of credit and providing additional liquidity.

At February 12, 2018, we had a total of $10.9 billion of committed revolving and demand credit facilities:

Amount	Unused capacity	Borrower	Description	Matures
Committed, syndicated, revolving, extendible, senior unsecured credit facilities:				
$3.0 billion	$3.0 billion	TCPL	Supports TCPL's Canadian dollar commercial paper program and for general corporate purposes	December 2022
US$2.0 billion	US$2.0 billion	TCPL	Supports TCPL's U.S. dollar commercial paper program and for general corporate purposes	December 2018
US$1.0 billion	US$0.9 billion	TCPL USA	Used for TCPL USA general corporate purposes, guaranteed by TCPL	December 2018
US$1.0 billion	US$1.0 billion	Columbia	Used for Columbia general corporate purposes, guaranteed by TCPL	December 2018
US$0.5 billion	US$0.5 billion	TAIL	Supports TAIL's U.S. dollar commercial paper program and for general corporate purposes, guaranteed by TCPL	December 2018
Demand senior unsecured revolving credit facilities:				
$1.9 billion	$0.4 billion	TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity; TCPL USA facility guaranteed by TCPL	Demand
MXN$5.0 billion	MXN$4.8 billion	Mexican subsidiary	Used for Mexico general corporate purposes, guaranteed by TCPL	Demand

At February 12, 2018, our operated affiliates had an additional $0.5 billion of undrawn capacity on committed credit facilities.

Contractual obligations

Our contractual obligations include our long-term debt, operating leases, purchase obligations and other liabilities incurred in our business such as environmental liability funds and employee pension and post-retirement benefit plans.

Payments due (by period)

at December 31, 2017 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Notes payable	1,763	1,763	—	—	—
Long-term debt and junior subordinated notes	41,748	2,866	6,024	4,014	28,844
Operating leases[1]	790	71	145	133	441
Purchase obligations	4,260	2,292	647	310	1,011
	48,561	6,992	6,816	4,457	30,296

1 Future payments for various premises, services and equipment, less sub-lease receipts.

Long-term debt and junior subordinated notes

At the end of 2017, we had $34.7 billion of long-term debt and $7.0 billion of junior subordinated notes outstanding, compared to $40.2 billion of long-term debt and $3.9 billion of junior subordinated notes at December 31, 2016.

Total notes payable was $1.8 billion at the end of 2017 compared to $0.8 billion at the end of 2016.

We attempt to smooth the maturity profile of our debt. The weighted-average maturity of our long-term debt and junior subordinated notes to final maturity, is 20 years, with the majority maturing beyond five years.

Interest payments

At December 31, 2017, scheduled interest payments related to our long-term debt and junior subordinated notes were as follows:

at December 31, 2017 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Long-term debt	21,364	1,722	3,071	2,586	13,985
Junior subordinated notes	23,047	374	750	750	21,173
	44,411	2,096	3,821	3,336	35,158

Operating leases

Our operating leases for premises, services and equipment expire at different times between now and 2052. Some of our operating leases include the option to renew the agreement for one to 25 years.

Purchase obligations

We have purchase obligations that are transacted at market prices and in the normal course of business, including long-term natural gas transportation and purchase arrangements.

Capital expenditure commitments include obligations related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts.

Payments due (by period)[1]

at December 31, 2017 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Canadian Natural Gas Pipelines					
Transportation by others[2]	889	82	161	139	507
Capital spending[3]	307	306	1	—	—
U.S. Natural Gas Pipelines					
Transportation by others[2]	762	156	184	117	305
Capital spending[3]	397	387	9	1	—
Mexico Natural Gas Pipelines					
Capital spending[3]	743	687	56	—	—
Liquids Pipelines					
Capital spending[3]	70	70	—	—	—
Other	26	5	9	6	6
Energy					
Commodity purchases	243	156	87	—	—
Capital spending[3]	434	378	56	—	—
Other[4]	306	31	47	36	192
Corporate					
Capital spending[3]	83	34	37	11	1
	4,260	2,292	647	310	1,011

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

2 Demand rates are subject to change. The contractual obligations in the table are based on demand volumes only and exclude variable charges incurred when volumes flow.

3 Amounts are primarily for capital expenditures and contributions to equity investments for capital projects. Amounts are estimates and are subject to variability based on timing of construction and project requirements.

4 Includes estimates of certain amounts which are subject to change depending on plant-fired hours, the consumer price index, actual plant maintenance costs, plant salaries as well as changes in regulated rates for fuel transportation.

Outlook

We are developing quality projects under our $47 billion capital program. These long-life infrastructure assets are supported by long-term commercial arrangements or regulated cost of service business models and, once completed, are expected to generate significant growth in earnings and cash flow.

Our $47 billion capital program is comprised of $23 billion of near-term projects and $24 billion of commercially supported medium and longer-term projects, each of which are subject to key commercial or regulatory approvals. The portfolio is expected to be financed through our growing internally generated cash flow and a combination of other funding options including:

- senior debt
- project financing
- preferred shares
- hybrid securities
- additional drop downs of our U.S. natural gas pipeline assets to TC PipeLines, LP
- asset sales
- potential involvement of strategic or financial partners
- common shares issued under our DRP
- common shares issued under our ATM programs, as appropriate
- lastly, discrete common equity issuances.

GUARANTEES

Sur de Texas

We and our partner on the Sur de Texas pipeline, IEnova, have jointly guaranteed the obligations for construction services during the construction of the pipeline. The guarantees have terms ranging to 2020.

At December 31, 2017, our share of potential exposure under the Sur de Texas pipeline guarantees was estimated to be $315 million. The carrying amount of the guarantee was approximately $2 million.

Bruce Power

We and our partner, BPC Generation Infrastructure Trust, have each severally guaranteed a Bruce Power contingent financial obligation related to a lease agreement. The Bruce Power guarantee has a term to 2018.

At December 31, 2017, our share of the potential exposure under the Bruce Power guarantee was estimated to be $88 million. The carrying amount of the guarantee was approximately $1 million.

Other jointly owned entities

We and our partners in certain other jointly owned entities have also guaranteed (jointly, severally, or jointly and severally) the financial performance of these entities. Such agreements include guarantees and letters of credit which are primarily related to delivery of natural gas, construction services including purchase agreements and the payment of liabilities. The guarantees have terms ranging to 2059.

Our share of the potential exposure under these assurances was estimated at December 31, 2017 to be $104 million. The carrying amount of these guarantees was approximately $13 million. In some cases, if we make a payment that exceeds our ownership interest, the additional amount must be reimbursed by our partners.

The carrying value of these guarantees has been included in other long-term liabilities.

OBLIGATIONS – PENSION AND OTHER POST-RETIREMENT PLANS

In 2018, we expect to make funding contributions of approximately $98 million for the defined benefit pension plans, approximately $7 million for other post-retirement benefit plans and approximately $45 million for the savings plan and defined contribution pension plans. In addition, we expect to provide a $27 million letter of credit to the Canadian defined benefit plan for solvency funding requirements.

In 2017, we made funding contributions of $163 million to our defined benefit pension plans, $7 million for the other post-retirement benefit plans and $42 million for the savings plan and defined contribution pension plans. We also provided a $27 million letter of credit to the Canadian defined benefit plan for solvency funding requirements.

Outlook

The next actuarial valuation for our pension and other post-retirement benefit plans will be carried out as at January 1, 2018. Based on current market conditions, we expect funding requirements for these plans to approximate 2017 levels for several years. This will allow us to amortize solvency deficiencies in the plans, in addition to normal funding costs.

Our net benefit cost for our defined benefit and other post-retirement plans decreased to $106 million in 2017 from $116 million in 2016 mainly due to higher expected returns on plan assets, partially offset by 2017 settlement charges.

Future net benefit costs and the amount we will need to contribute to fund our plans will depend on a range of factors, including:

- interest rates
- actual returns on plan assets
- changes to actuarial assumptions and plan design
- actual plan experience versus projections
- amendments to pension plan regulations and legislation.

We do not expect future increases in the level of funding needed to maintain our plans to have a material impact on our liquidity.

Other information

RISKS AND RISK MANAGEMENT

Risk management is integral to the successful operation of our business. Our strategy is to ensure that our risks and related exposures are in line with our business objectives and risk tolerance.

We manage risk through a centralized assessment process that identifies and allows us to qualify risk that could materially impact our strategic objectives. Risk assessment is built into our decision-making processes at all levels.

Our Board of Directors' Governance Committee oversees our risk management activities, which includes ensuring appropriate management systems are in place to manage our risks, including adequate Board oversight of our risk management policies, programs and practices. Other Board committees oversee specific types of risk:

- the Human Resources Committee oversees executive resourcing, organizational capabilities and compensation risk to ensure compensation practices align with our overall business strategy
- the Health, Safety and Environment Committee oversees operational, safety and environmental risk
- the Audit Committee oversees management's role in monitoring financial risk.

Our executive leadership team is accountable for developing and implementing risk management plans and actions, and effective risk management is reflected in their compensation.

The following is a summary of general risks that affect our company. Risks specific to each operating business segment can be found in each business segment discussion.

Risk and Description	Impact	Monitoring and Mitigation
Business interruption		
Operational risks, including labour disputes, equipment malfunctions or breakdowns, acts of terror and sabotage, or natural disasters and other catastrophic events, including those related to climate change.	Decrease in revenues, increase in operating costs or legal proceedings or other expenses all of which could reduce our earnings. Losses not covered by insurance could have an adverse effect on operations, cash flow and financial position.	We have incident, emergency and crisis management systems to ensure an effective response to minimize further loss or injuries and to enhance our ability to resume operations. We also have a Business Continuity Program that determines critical business processes and develops resumption plans to ensure process continuity. We have comprehensive insurance to mitigate certain of these risks, but insurance does not cover all events in all circumstances.
Reputation and relationships		
Our operations and growth prospects require us to have strong relationships with key stakeholders including Indigenous communities, landowners, governments and government agencies and environmental non-governmental organizations. Inadequately managing expectations and issues important to stakeholders, including those related to climate change, could affect our reputation and our ability to operate and grow, and continue to access sources of capital.	Our reputation with stakeholders, including Indigenous communities, can have a significant impact on our operations and projects, infrastructure development and overall reputation. Should investors develop negative perceptions regarding the energy infrastructure business, future access to investment capital could be negatively impacted.	Our Stakeholder Engagement Framework guides our engagement activities with stakeholders. Our four core values – safety, integrity, responsibility and collaboration – are at the heart of our commitment to stakeholder engagement, and guide us in our interactions with stakeholders. We also have specific stakeholder programs and policies that set requirements, assess risks and ensure compliance with legal and policy requirements.
Execution and capital costs		
Investing in large infrastructure projects involves substantial capital commitments and associated execution risks based on the assumption that these assets will deliver an attractive return on investment in the future.	While we carefully consider the expected cost of our capital projects, under some contracts, we bear capital cost overrun and schedule risk which may decrease our return on these projects.	Our Project Governance Program supports project execution and operational excellence. The program aligns with TransCanada's Operational Management System that provides the framework and standards to optimize project execution, ensuring timely and on budget execution. We prefer to contractually structure our projects to recover development costs if a project does not proceed and cost overruns occur. However, under some contracts, we share or bear the cost of execution risk.

Risk and Description	Impact	Monitoring and Mitigation
Cyber security		
We rely on our information technology to process, transmit and store electronic information, including information we use to safely operate our assets. We continue to face cyber security risks, and could be subject to cyber-security events directed against our information technology. The methods used to obtain unauthorized access, disable or degrade service or sabotage systems are constantly evolving and may be difficult to anticipate or to detect for long periods of time.	A breach in the security of our information technology could expose our business to a risk of loss, misuse or interruption of critical information and functions. This could affect our operations, damage our assets, result in safety incidents, damage to the environment, reputational harm, competitive disadvantage, regulatory enforcement actions and potential litigation, which could have a material adverse effect on our operations, financial position and results of operations.	We have a comprehensive cyber security strategy which aligns with industry and recognized standards for cyber security. This strategy is regularly reviewed and updated, and the status of our cyber security program is reported to the Audit Committee on a quarterly basis. The program includes cyber security risk assessments, continuous monitoring of networks and other information sources for threats to the organization, comprehensive incident response plans/ processes and a cyber security awareness program for employees. We have insurance which covers reasonably foreseeable losses due to damage to our facilities, and losses incurred by others, as a result of a cyber security event.

Health, safety and environment

The Board's Health, Safety and Environment (HSE) committee oversees operational risk, people and process safety, security of personnel and environmental risks, and monitors compliance with our HSE programs through regular reporting from management. We use an integrated management system that establishes a framework for managing these risks and which is used to capture, organize, document, monitor and improve our related policies, programs and procedures.

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

- planning – risk and regulatory assessment, objective and target setting, defining roles and responsibilities
- implementing – development and implementation of programs, procedures and standards to manage operational risk
- reporting – incident reporting and investigation, and performance monitoring
- action – assurance activities and review of performance by management.

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

- overall HSE corporate governance
- operational performance and preventive maintenance metrics
- asset integrity programs
- emergency preparedness, incident response and evaluation
- people and process safety performance metrics
- our Environment Program
- developments in and compliance with applicable legislation and regulations, including those related to the environment.

Health and safety

The safety of our employees, contractors and the public, as well as the integrity of our energy and pipeline infrastructure, is a top priority. All assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are brought into service only after all necessary requirements have been satisfied.

In 2017, we spent $1.1 billion for pipeline integrity on the Natural Gas and Liquids pipelines we operate, a $252 million increase over 2016 due to an increase of in-line pipeline inspections and enhanced system availability. Additionally, pipeline integrity spending will fluctuate based on the results of annual risk assessments conducted on our pipeline systems and evaluations of information obtained from recent inspections and maintenance activities.

Our Energy operations spending associated with process safety, and various integrity programs, is used to minimize risk to employees and the public, equipment, the surrounding environment, and to prevent disruptions to serving the energy needs of our customers.

As described in the Business interruption section above, we have a set of procedures in place to manage our response to natural disasters which include catastrophic events such as forest fires, tornadoes, earthquakes, floods, volcanic eruptions and hurricanes. The procedures, which are included in our Emergency Management Program, are designed to help protect the health and safety of our employees, minimize risk to the public and limit the potential for adverse effects on the environment.

Environmental risk, compliance and liabilities
We maintain an Environment Program to minimize potentially adverse environmental impacts. This program identifies our requirements to proactively and systematically manage environmental hazards and risks throughout the lifecycle of our assets.

Our primary sources of risk related to the environment include:
- changing regulations and costs associated with our emissions of air pollutants and GHG
- product releases, including crude oil, diluent and natural gas, that may cause harm to the environment (land, water and air)
- use, storage and disposal of chemicals and hazardous materials
- conformance and compliance with corporate and regulatory policies and requirements and new regulations.

Our assets are subject to federal, state, provincial and local environmental statutes and regulations governing environmental protection, including air and GHG emissions, water quality, species at risk, wastewater discharges and waste management. Operating our assets requires obtaining and complying with a wide variety of environmental registrations, licenses, permits and other approvals and requirements. Failure to comply could result in administrative, civil or criminal penalties, remedial requirements or orders affecting future operations.

Through the implementation of our Environment Program, we continually monitor our facilities to ensure compliance with all environmental requirements. We routinely monitor proposed changes in environmental policy, legislation and regulation, and where the risks are uncertain or have the potential to affect our ability to effectively operate our business, we comment on proposals independently or through industry associations.

On November 28, 2017, in connection with the line break experienced on the Keystone Pipeline System near Amherst, South Dakota on November 16, 2017, the PHMSA issued a Correction Action Order (the "Amherst CAO") directing us to, among other things, repair the pipeline in accordance with an approved repair plan, return the pipeline to service in accordance with an approved return to service plan, operate the affected section of the pipeline at a reduced operating pressure until further directed and facilitate an investigation into the cause of the incident. We are fully cooperating with PHMSA on all matters relating to this incident and the Amherst CAO. Other than the Amherst CAO, we are not aware of any material outstanding orders, claims or lawsuits against us related to releasing or discharging any material into the environment or in connection with environmental protection.

Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any failure to comply, and potential limitations on operations.

Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated properties, and with damage claims arising from the contamination of properties.

The timing and complete extent of future expenditures related to environmental matters is difficult to estimate accurately because:
- environmental laws and regulations (and interpretation and enforcement of them) change
- new claims can be brought against our existing or discontinued assets
- our pollution control and clean-up cost estimates may change, especially when our current estimates are based on preliminary site investigation or agreements
- we may find new contaminated sites, or what we know about existing sites could change
- where there is potentially more than one responsible party involved in litigation, we cannot estimate our joint and several liability with certainty.

At December 31, 2017, accruals related to these obligations totaled $34 million (2016 – $39 million), representing the estimated amount we will need to manage our currently known environmental liabilities. We believe we have considered all necessary contingencies and established appropriate reserves for environmental liabilities, however a risk exists that unforeseen matters may arise requiring us to set aside additional amounts. We adjust reserves regularly to account for changes in liabilities.

Climate change and related regulation risk
We own assets and have business interests in a number of regions subject to GHG emissions regulations, including GHG emissions management and carbon pricing policies. In 2017, we incurred $63 million (2016 – $62 million) of expense under existing carbon pricing programs. Across North America, there are a variety of new and evolving initiatives in development at the federal, regional, state and provincial level aimed at reducing GHG emissions. We actively monitor and submit comments to regulators as these new and evolving initiatives are undertaken. We support transparent climate change policies that lead to actual resolutions, allowing for sustainable and economically responsible natural resource development, but are appropriately flexible to adapt to economic realities and unintended outcomes. We expect that, over time, most of our assets will be subject to some form of regulation to

manage GHG emissions. Changes in regulations may result in higher operating costs or other expenses, or higher capital expenditures to comply with possible new regulations.

Existing policies

- the U.S. Environmental Protection Agency (EPA) published regulations related to fugitive methane emissions for new and modified compressor stations in the natural gas transmission and storage sector in 2015. In 2017, the EPA indicated its intention to reconsider this regulation
- B.C. has a tax on GHG emissions from fossil fuel combustion. We recover the compliance costs through the tolls our customers pay
- under the SGER in Alberta, established industrial facilities with GHG emissions above a certain threshold are required to reduce their emissions below an intensity baseline. The SGER program covers our natural gas pipelines and Energy assets. Natural gas pipeline compliance costs are recovered through regulated tolls. A portion of the compliance costs for the Energy assets are recovered through market pricing and hedging activities
- Québec and California have GHG cap and trade programs linked under the Western Climate Initiative (WCI) GHG emissions market. In Québec, the Bécancour cogeneration plant is subject to this program. The government allocates free emission units for the majority of Bécancour's compliance requirements. The remaining requirements were met with GHG instruments purchased at auctions or secondary markets. The costs of these emissions units were recovered through commercial contracts. The Canadian Mainline natural gas pipeline facilities in Québec are also subject to this program and have purchased compliance instruments. In California, TransCanada has costs associated with the cap and trade program from our electricity marketing activities
- Ontario launched a cap and trade program under the WCI on January 1, 2017. The Canadian Mainline natural gas pipeline facilities in Ontario are subject to this program and have purchased compliance instruments which are recoverable in tolls. Although TransCanada's electricity generation facilities in the province are not directly subject to this program, TransCanada contributes to the compliance costs through distribution rates
- on March 23, 2017, the California Air Resources Board published regulations related to monitoring and repairing methane leaks. Tuscarora Gas Transmission facilities are required to comply with these regulations
- Washington State adopted emission standards to cap and reduce GHGs from certain stationary sources in September 2016. Some GTN compressor stations in Washington are potentially impacted by the standards beginning in 2020.

Anticipated policies

- future legislative and regulatory programs could significantly restrict emissions of GHGs including methane across our operations
- the Government of Canada has proposed a federal plan to have carbon pricing in place in all Canadian jurisdictions in 2018. The plan would expand GHG pricing coverage of TransCanada assets to Saskatchewan, Manitoba and New Brunswick and is within the bounds of our previously anticipated changes to GHG regulations
- the Alberta government announced a climate change policy, the Climate Leadership Plan (CLP), in 2015. This policy will see the replacement of the SGER program with the Carbon Competitiveness Incentive Regulation, a performance standard-based GHG pricing program, on January 1, 2018
- Environment and Climate Change Canada issued a draft Methane Reduction Regulation on May 27, 2017. The draft regulations detail requirements to reduce methane emissions through operational and capital modifications
- the Government of Canada has proposed a federal plan, the Clean Fuel Standard, to implement a single national standard encompassing all fuel types and applications
- the Pennsylvania Department of Environmental Protection has proposed new operating permits for oil and gas facilities that include numerous requirements including methane leak detection and repair
- New York State announced its intent to adopt regulations to reduce methane from existing, new and modified facilities
- Maryland announced its intent to establish fugitive methane regulations for compressor stations
- the Government of Mexico has proposed to implement a carbon tax for all companies that exceed an annual emissions threshold
- the Saskatchewan and Manitoba governments each announced that large industrial emitters will be subject to a yet to be developed carbon pricing system.

Financial risks

We are exposed to market risk, counterparty credit risk and liquidity risk, and have strategies, policies and limits in place to mitigate their impact on our earnings, cash flow and, ultimately, shareholder value.

These strategies, policies and limits are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance. We manage market risk and counterparty credit risk within limits that are ultimately established by the Board, implemented by senior management and monitored by our risk management and internal audit groups. Management monitors compliance with market and counterparty risk management policies and procedures, and reviews the adequacy of the risk management framework, overseen by the Audit Committee. Our internal audit group assists the Audit Committee by carrying out regular and ad-hoc reviews of risk management controls and procedures, and reporting up to the Audit Committee.

Market risk

We build and invest in energy infrastructure projects, buy and sell energy commodities, issue short-term and long-term debt (including amounts in foreign currencies) and invest in foreign operations. Certain of these activities expose us to market risk from changes in commodity prices, foreign exchange rates and interest rates which may affect our earnings and the value of the financial instruments we hold. We assess contracts used to manage market risk to determine whether all, or a portion, meet the definition of a derivative.

Derivative contracts we use to assist in managing our exposure to market risk include:

- forwards and futures contracts – agreements to buy or sell a financial instrument or commodity at a specified price and date in the future
- swaps – agreements between two parties to exchange streams of payments over time according to specified terms
- options – agreements that give the purchaser the right (but not the obligation) to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period.

Power generation commodity price risk

We are exposed to commodity price movements as part of our normal business operations. A number of strategies are used to manage these exposures, including the following:

- committing a portion of expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to manage operational and price risks in our asset portfolio
- purchasing a portion of the natural gas required to fuel certain of our power plants or entering into contracts that base the sale price of electricity on the cost of natural gas, effectively locking in a margin
- meeting power sales commitments using power generation or fixed price purchase contracts, thereby reducing our exposure to fluctuating commodity prices.

In April and June 2017, we sold our U.S. Northeast power generation assets and in December 2017, we entered into an agreement to sell our outstanding U.S. power retail contracts as part of the continued wind down of our U.S. power marketing operations. The U.S. power retail contracts transaction is expected to close in the first quarter of 2018 subject to regulatory and other approvals. As a result of these sales, our exposure to commodity price risk has been reduced.

Natural gas storage commodity price risk

We manage our exposure to seasonal natural gas price spreads in the non-regulated natural gas storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. We simultaneously enter into forward purchase contracts of natural gas for injection into storage and offsetting forward sale contracts of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to natural gas price movements. Unrealized gains and losses on fair value adjustments recorded each period on these forward contracts are not necessarily representative of the amounts that will be realized on settlement.

Liquids marketing commodity price risk

The liquids marketing business began operations in 2016. We enter into short-term or long-term liquids pipeline and storage terminal capacity contracts. We fix a portion of our exposure by entering into derivative instruments to manage variable price fluctuations that arise from physical liquids transactions.

Foreign exchange and interest rate risk

We generate revenues and incur expenses that are denominated in currencies other than Canadian dollars. As a result, our earnings and cash flows are exposed to currency fluctuations.

A portion of our businesses generate earnings in U.S. dollars, but since we report our financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect our net income. As our U.S. dollar-denominated operations continue to grow, this exposure increases. The majority of this risk is offset by interest expense on U.S. dollar-denominated debt and by using foreign exchange derivatives.

We are exposed to interest rate risk resulting from financial instruments and contractual obligations containing variable interest rate components. We manage this using a combination of interest rate swaps and options.

Average exchange rate – U.S. to Canadian dollars

The average exchange rate for one U.S. dollar converted into Canadian dollars was as follows:

2017	**1.30**
2016	1.33
2015	1.28

The impact of changes in the value of the U.S. dollar on our U.S. operations is significantly offset by interest on U.S. dollar-denominated debt, as set out in the table below. Comparable EBIT is a non-GAAP measure. See page 8 for more information.

Significant U.S. dollar-denominated amounts

year ended December 31 (millions of US$)	**2017**	**2016**	**2015**
U.S. Natural Gas Pipelines comparable EBIT	**1,360**	947	562
Mexico Natural Gas Pipelines comparable EBIT[1]	**353**	215	130
U.S. Liquids Pipelines comparable EBIT	**604**	482	623
U.S. Power comparable EBIT	**100**	285	305
Interest on U.S. dollar-denominated long-term debt and junior subordinated notes	**(1,269)**	(1,127)	(911)
Capitalized interest on U.S. dollar-denominated capital expenditures	**3**	22	109
U.S. dollar-denominated allowance for funds used during construction	**259**	181	137
U.S. non-controlling interests and other	**182**	189	16
	1,592	1,194	971

1 Excludes interest expense on our inter-affiliate loan with Sur de Texas which is offset in interest income and other.

Net investment hedge

We hedge our net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, foreign exchange forward contracts and foreign exchange options.

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

	2017		**2016**	
at December 31 (millions of $)	**Fair value[1]**	**Notional or principal amount**	**Fair value[1]**	**Notional or principal amount**
U.S. dollar cross-currency interest rate swaps (maturing 2018 to 2019)[2]	**(199)**	**US 1,200**	(425)	US 2,350
U.S. dollar foreign exchange options (maturing 2018)	**5**	**US 500**	—	—
U.S. dollar foreign exchange forward contracts	**—**	**—**	(7)	US 150
	(194)	**US 1,700**	(432)	US 2,500

1 Fair values equal carrying values.

2 In 2017, consolidated net income includes net realized gains of $4 million (2016 – gains of $6 million) related to the interest component of cross-currency swap settlements which are reported within interest expense.

The notional amounts and fair value of U.S. dollar-denominated debt designated as a net investment hedge were as follows:

at December 31 (millions of $)	2017	2016
Notional amount	**25,400 (US 20,200)**	26,600 (US 19,800)
Fair value	**28,900 (US 23,100)**	29,400 (US 21,900)

Counterparty credit risk

We have exposure to counterparty credit risk in the following areas:

- accounts receivable
- the fair value of derivative assets
- cash and cash equivalents.

If a counterparty fails to meet its financial obligations to us according to the terms and conditions of the financial instrument, we could experience a financial loss. We manage our exposure to this potential loss using recognized credit management techniques, including:

- dealing with creditworthy counterparties – a significant amount of our credit exposure is with investment grade counterparties or, if not, is generally partially supported by financial assurances from investment grade parties
- setting limits on the amount we can transact with any one counterparty – we monitor and manage the concentration of risk exposure with any one counterparty, and reduce our exposure when we feel we need to and when it is allowed under the terms of our contracts
- using contract netting arrangements and obtaining financial assurances such as guarantees, letters of credit or cash when we believe it is necessary.

There is no guarantee that these techniques will protect us from material losses.

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At December 31, 2017, we had no significant credit losses, no significant credit risk concentration and no significant amounts past due or impaired. At December 31, 2016, we had a credit risk concentration with one counterparty of $200 million (US$149 million).

We have significant credit and performance exposure to financial institutions because they hold cash deposits and provide committed credit lines and letters of credit that help manage our exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

For our Canadian regulated natural gas pipeline assets, counterparty credit risk is also managed through application of tariff provisions as approved by the NEB.

Liquidity risk

Liquidity risk is the risk that we will not be able to meet our financial obligations as they come due. We manage our liquidity by continuously forecasting our cash flow and making sure we have adequate cash balances, cash flow from operations, committed and demand credit facilities and access to capital markets to meet our operating, financing and capital expenditure obligations under both normal and stressed economic conditions. See Financial condition for more information about our liquidity.

Legal proceedings

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

CONTROLS AND PROCEDURES

We meet Canadian and U.S. regulatory requirements for disclosure controls and procedures, internal control over financial reporting and related CEO and CFO certifications.

Disclosure controls and procedures

Under the supervision and with the participation of management, including our President and CEO and our CFO, we carried out quarterly evaluations of the effectiveness of our disclosure controls and procedures, including for the year ended December 31, 2017, as required by the Canadian securities regulatory authorities and by the SEC. Based on this evaluation, our President and CEO and our CFO have concluded that the disclosure controls and procedures are effective in that they are designed to ensure that the information we are required to disclose in reports we file with or send to securities regulatory authorities is recorded, processed, summarized and reported accurately within the time periods specified under Canadian and U.S. securities laws.

Management's annual report on internal control over financial reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting, which is a process designed by, or under the supervision of, our President and CEO and our CFO, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Under the supervision and with the participation of management, including our President and CEO and our CFO, an evaluation of the effectiveness of the internal control over financial reporting was conducted as of December 31, 2017, based on the criteria described in "Internal Control – Integrated Framework" issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2017, the internal control over financial reporting was effective.

Our internal control over financial reporting as of December 31, 2017 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included in this document.

CEO and CFO certifications

Our President and CEO and our CFO have attested to the quality of the public disclosure in our fiscal 2017 reports filed with Canadian securities regulators and the SEC, and have filed certifications with them.

Changes in internal control over financial reporting

Effective April 1, 2017, management successfully integrated Columbia, which we acquired on July 1, 2016, into our existing enterprise resource planning (ERP) system. As a result of the Columbia ERP system integration, certain processes supporting our internal control over financial reporting for Columbia operations changed in second quarter 2017, however, overall controls and procedures we follow in establishing internal controls over financial reporting were not significantly impacted.

Other than as noted above, there were no changes during the year covered by this annual report that had or are reasonably likely to have a material impact on our internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

When we prepare financial statements that conform with GAAP, we are required to make certain estimates and assumptions that affect the timing and amounts we record for our assets, liabilities, revenues and expenses because these items may be affected by future events. We base the estimates and assumptions on the most current information available, using our best judgment. We also regularly assess the assets and liabilities themselves.

The following accounting estimates require us to make the most significant assumptions when preparing our financial statements and changes in these assumptions could have a material impact on the financial statements from those estimates.

Rate-regulated accounting

Under GAAP, an asset qualifies for use of RRA when it meets three criteria:

- a regulator must establish or approve the rates for the regulated services or activities
- the regulated rates must be designed to recover the cost of providing the services or products
- it is reasonable to assume that rates set at levels to recover the cost can be charged to (and collected from) customers because of the demand for services or products and the level of direct and indirect competition.

We believe that the regulated natural gas pipelines projects we account for using RRA meet these criteria. The most significant impact of using these principles is the timing of when we recognize certain expenses and revenues, which is based on the economic impact of the regulators' decisions about our revenues and tolls, and may be different from what would otherwise be expected under GAAP. Regulatory assets represent costs that are expected to be recovered in customer rates in future periods. Regulatory liabilities are amounts that are expected to be returned to customers through future rate setting processes. A decrease in regulatory assets of $27 million and an increase in regulatory liabilities in the amount of $1,659 million were recorded as a result of U.S. Tax Reform. See page 13 for more information.

Regulatory assets and liabilities

at December 31 (millions of $)	2017	2016
Regulatory assets		
Long-term assets	**1,376**	1,322
Short-term assets (included in other current assets)	**23**	33
Regulatory liabilities		
Long-term liabilities	**4,321**	2,121
Short-term liabilities (included in accounts payable and other)	**263**	178

Impairment of long-lived assets, equity investments and goodwill

We review long-lived assets (such as plant, property and equipment), equity investments and intangible assets for impairment whenever events or changes in circumstances lead us to believe we might not be able to recover an asset's carrying value. If the total of the undiscounted future cash flows that we estimate for an asset is less than its carrying value, we consider its fair value to be less than its carrying value and we calculate and record an impairment loss to recognize this. For goodwill, if fair value of the reporting unit is less than carrying value we consider it to be impaired.

In 2017, the following impairments were recorded:

- a $954 million after-tax charge on the carrying value of our investment in Energy East and related projects
- a $16 million after-tax charge on the remaining carrying value of certain Energy turbine equipment
- a $12 million after-tax charge related to the remaining carrying value of our investment in TransGas.

In 2016, the following impairments were recorded:

- a goodwill impairment charge on the full carrying value of Ravenswood goodwill of $656 million after tax
- a $244 million after-tax charge with respect to the Alberta PPA terminations.

Energy East and related projects

In September 2017, we requested the NEB suspend the review of the Energy East and Eastern Mainline project applications for 30 days to provide time for us to conduct a careful review of the NEB's changes, announced on August 23, 2017, regarding the list of issues and environmental assessment factors related to the projects and how these changes impact the projects' costs, schedules and viability.

In October 2017, after careful review of the changed circumstances, we informed the NEB that we would not be proceeding with the Energy East and Eastern Mainline project applications. We also notified Québec's Ministère du Developpement durable, de l'Environnement, et de la Lutte contre les changements climatiques that we are withdrawing the Energy East project from the environmental review process. As the Energy East pipeline was also to provide transportation services for the Upland pipeline, the U.S. Department of State was notified in October 2017 that we would no longer be pursuing the U.S. Presidential Permit application for that project.

We reviewed the approximate $1.3 billion carrying value of the projects, including AFUDC capitalized since inception, and recorded a $954 million after-tax non-cash charge in fourth quarter 2017. We ceased capitalizing AFUDC on the projects effective August 23, 2017, being the date of the NEB's announced scope changes. With Energy East's inability to reach a regulatory decision, no recoveries of costs from third parties are forthcoming.

Energy Turbine Equipment

At December 31, 2017, we recognized a non-cash impairment charge of $16 million after tax related to the remaining carrying value of certain turbine equipment after determining that it was no longer recoverable. This turbine equipment was previously purchased for a power development project that did not proceed. In 2015, we recognized a non-cash impairment charge of $43 million after tax related to this equipment after evaluating specific capital opportunities and concluding the carrying value was not fully recoverable. The impairment charge was based on the excess of the carrying value over the estimated fair value of the equipment which was determined based on a comparison to similar assets available for sale in the market at that time.

TransGas

In third quarter 2017, we recognized an impairment charge of $12 million after tax on our 46.5 per cent equity investment in TransGas. TransGas constructed and operated a natural gas pipeline in Colombia for a 20-year build-own-transfer contract term. As per the terms of the agreement, upon completion of the 20-year contract in August 2017, TransGas transfered its pipeline assets to Transportadora de Gas Internacional S.A.. The impairment charge represents the write-down of the remaining carrying value of our equity investment in TransGas.

Alberta PPA terminations

On March 7, 2016, we issued notice to the Balancing Pool of the decision to terminate our Sheerness and Sundance A PPAs. In accordance with a provision in the PPAs, a buyer is permitted to terminate the arrangement if a change in law occurs that makes the arrangement unprofitable or more unprofitable. As a result of recent changes in law surrounding the Alberta SGER, we expected increasing costs related to carbon emissions to continue throughout the remaining terms of the PPAs resulting in increasing unprofitability. As such, in 2016, we recognized a non-cash impairment charge of $155 million after tax, which represented the carrying value of the PPAs. Upon final settlement of the Alberta PPA terminations in December 2016, we transferred to the Balancing Pool a package of environmental credits that were being held to offset the PPA emissions costs and recorded a non-cash charge of $68 million after tax related to the carrying value of these environmental credits.

We also recognized a non-cash impairment charge of $21 million after tax which represented the carrying value of the equity investment in ASTC Partnership, which held the similarly terminated Sundance B PPA.

Keystone XL

At December 31, 2017, we reviewed our remaining investment in Keystone XL and related projects with a carrying value of $475 million (2016 – $526 million) and found no events or changes in circumstance indicating that the carrying value may not be recoverable.

At December 31, 2015, in connection with the denial of the U.S. Presidential permit, we evaluated our $4.3 billion investment in Keystone XL and related projects, including Keystone Hardisty Terminal, for impairment. As a result of our analysis, we determined that the carrying amount of these assets was no longer recoverable, and recognized a total non-cash impairment charge of $3.7 billion ($2.9 billion after tax). The impairment charge was based on the excess of the carrying value over the estimated fair value of $621 million.

The estimated fair value related to plant and equipment at December 31, 2015 was based on the price that would be received to sell the assets in their current condition. Key assumptions used in the determination of selling price included an estimated two-year disposal period and the then current weak energy market conditions. The valuation considered a variety of potential selling prices that were based on the various markets that could be used in order to dispose of these assets.

The estimated fair value of the terminals, including Keystone Hardisty Terminal, at December 31, 2015, was determined using a discounted cash flow approach as a measure of fair value. We recorded a full impairment charge on capitalized interest and other intangible assets as these costs were no longer probable to be recovered.

Goodwill

We test goodwill for impairment annually or more frequently if events or changes in circumstances lead us to believe it might be impaired. We can elect to first assess qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired, and if we conclude that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, we use a two-step process to test for impairment: We can also elect to proceed directly to the two-step process to test any reporting unit for impairment. This two-step process involves the following:

1. First, we compare the fair value of the reporting unit to its book value, including its goodwill. If fair value is less than book value, we consider our goodwill to be impaired.
2. Next, we measure the amount of the impairment by calculating the implied fair value of the reporting unit's goodwill. We do this by deducting the fair value of the tangible and intangible net assets of the reporting unit from the fair value we calculated in the first step. To the extent the goodwill's carrying value exceeds its implied fair value, we record an impairment charge.

We determine the fair value of a reporting unit based on our projections of future cash flows, which involves making estimates and assumptions about commodity and capacity prices, market supply and demand, growth opportunities, output levels, competition from other companies, operating costs, regulatory changes, discount rates and earnings multiples.

If our assumptions change significantly, our requirement to record an impairment charge could also change.

At December 31, 2017, the estimated fair value of Great Lakes exceeded its carrying value by less than ten per cent. We measured the fair value of this reporting unit using a discounted cash flow analysis in our most recent valuation. Assumptions used in the analysis regarding Great Lakes' ability to realize long-term value in the North American energy market included the reduction in Great Lakes' rates effective October 1, 2017 as a result of the expected outcome of 2017 Great Lakes Settlement. This reduction in rates was largely offset by expected cash flows from the long-term transportation contract with the Canadian Mainline, other opportunities to increase utilization on the system and the 2017 Great Lakes Settlement elimination of the revenue sharing mechanism with its customers. Although evolving market conditions and other factors relevant to Great Lakes' long term financial performance have been positive, there is a risk that reductions in future cash flow forecasts or adverse changes in other key assumptions could result in a future impairment of a portion of the goodwill balance relating to Great Lakes. Our share of the goodwill related to Great Lakes, net of non-controlling interests, was US$379 million at December 31, 2017 (2016 – US$382 million).

As a result of information received during the process to monetize our U.S. Northeast power generation assets, in third quarter 2016, it was determined that the fair value of Ravenswood did not exceed its carrying value, including goodwill. The fair value of the reporting unit was determined using a combination of methods including a discounted cash flow approach and a range of expected consideration from a potential sale. The expected cash flows were discounted using a risk-adjusted discount rate to determine the fair value. As a result, we recorded a goodwill impairment charge on the full carrying value of Ravenswood goodwill of $1,085 million ($656 million after tax) within the Energy segment. The impairment charge was recorded prior to Ravenswood's reclassification to assets held for sale.

Asset retirement obligations

When there is a legal obligation to set aside funds to cover future abandonment costs, and we can reasonably estimate them, we recognize the fair value of the ARO in our financial statements.

We cannot determine when we will retire many of our liquids pipelines, natural gas pipelines and transportation facilities, and regulated natural gas storage systems because we intend to operate them as long as there is supply and demand, and so we have not recorded obligations for them.

For those we do record, we use the following assumptions:

- when we expect to retire the asset
- the scope of abandonment and reclamation activities that are required
- inflation and discount rates.

The ARO is initially recorded when the obligation exists and is subsequently accreted through charges to operating expenses.

We continue to evaluate our future abandonment obligations and costs and monitor developments that could affect the amounts we record.

FINANCIAL INSTRUMENTS

Non-derivative financial instruments

Fair value of non-derivative financial instruments

The fair value of long-term debt and junior subordinated notes has been estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data service providers.

Available for sale assets are recorded at fair value which is calculated using quoted market prices where available. Certain non-derivative financial instruments including cash and cash equivalents, accounts receivable, intangible and other assets, notes payable, accounts payable and other, accrued interest and other long-term liabilities have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity and would be classified in Level II of the fair value hierarchy.

Credit risk has been taken into consideration when calculating the fair value of non-derivative financial instruments.

Derivative instruments

We use derivative instruments to reduce volatility associated with fluctuations in commodity prices, interest rates and foreign exchange rates. Derivative instruments, including those that qualify and are designated for hedge accounting treatment, are recorded at fair value.

The majority of derivative instruments that are not designated or do not qualify for hedge accounting treatment have been entered into as economic hedges to manage our exposure to market risk (held for trading). Changes in the fair value of held for trading derivative instruments are recorded in net income in the period of change. This may expose us to increased variability in reported operating results since the fair value of the held for trading derivative instruments can fluctuate significantly from period to period.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipelines exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, can be recovered or refunded through the tolls charged by us. As a result, these gains and losses are deferred as regulatory assets or regulatory liabilities and are refunded to or collected from the ratepayers in subsequent years when the derivative settles.

Fair value of derivative instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses market rates and applies a discounted cash flow valuation model. The fair value of commodity derivatives has been calculated using a market approach which bases the fair value measures on a comparable transaction using quoted market prices, or in the absence of quoted market prices, third-party broker quotes or other valuation techniques. Credit risk has been taken into consideration when calculating the fair value of derivative instruments.

Balance sheet presentation of derivative instruments

The balance sheet presentation of the fair value of derivative instruments is as follows:

at December 31 (millions of $)	**2017**	**2016**
Other current assets	**332**	376
Intangible and other assets	**73**	133
Accounts payable and other	**(387)**	(607)
Other long-term liabilities	**(72)**	(330)
	(54)	(428)

Anticipated timing of settlement of derivative instruments

The anticipated timing of settlement of derivative instruments assumes constant commodity prices, interest rates and foreign exchange rates. Settlements will vary based on the actual value of these factors at the date of settlement.

at December 31, 2017 (millions of $)	Total fair value	2018	2019 and 2020	2021 and 2022
Derivative instruments held for trading				
Assets	389	320	64	5
Liabilities	(244)	(218)	(26)	—
Derivative instruments in hedging relationships				
Assets	16	12	—	4
Liabilities	(215)	(169)	(46)	—
	(54)	(55)	(8)	9

Unrealized and realized gains/(losses) on derivative instruments

The following summary does not include hedges of our net investment in foreign operations.

year ended December 31 (millions of $)	2017	2016
Derivative instruments held for trading[1]		
Amount of unrealized gains/(losses) in the year		
Commodities[2]	**62**	123
Foreign exchange	**88**	25
Interest rate	**(1)**	—
Amount of realized (losses)/gains in the year		
Commodities	**(107)**	(204)
Foreign exchange	**18**	62
Interest rate	**1**	—
Derivative instruments in hedging relationships		
Amount of realized gains/(losses) in the year		
Commodities	**23**	(167)
Foreign exchange	**5**	(101)
Interest rate	**1**	4

1 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell commodities are included net in revenues. Realized and unrealized gains and losses on interest rate and foreign exchange held for trading derivative instruments are included net in interest expense and interest income and other, respectively.

2 In 2017, there were no gains or losses included in net income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur (2016 - net loss of $42 million).

Derivatives in cash flow hedging relationships

The components of the consolidated statement of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests is as follows:

year ended December 31 (millions of $, pre-tax)	2017	2016
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Commodities	**(1)**	39
Interest rate	**4**	5
	3	44
Reclassification of (losses)/gains on derivative instruments from AOCI to net income (effective portion)[1]		
Commodities[2]	**(20)**	57
Interest rate[3]	**17**	14
	(3)	71

1 No amounts have been excluded from the assessment of hedge effectiveness. In 2017 and 2016, there were no gains or losses included in net income related to ineffective portions. Amounts in parentheses indicate losses recorded to OCI and AOCI.

2 Reported within revenues on the consolidated statement of income.

3 Reported within interest expense on the consolidated statement of income.

Credit risk related contingent features of derivative instruments

Derivatives often contain financial assurance provisions that may require us to provide collateral if a credit risk-related contingent event occurs (for example, if our credit rating is downgraded to non-investment grade). We may also need to provide collateral if the fair value of our derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at December 31, 2017, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $2 million (2016 – $19 million), with collateral provided in the normal course of business of nil (2016 – nil). If the credit-risk-related contingent features in these agreements were triggered on December 31, 2017, we would have been required to provide additional collateral of $2 million (2016 – $19 million) to our counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

We have sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

ACCOUNTING CHANGES

Changes in accounting policies for 2017

Inventory

In July 2015, the Financial Accounting Standards Board (FASB) issued new guidance on simplifying the measurement of inventory. The new guidance specifies that an entity should measure inventory within the scope of this guidance at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This new guidance was effective January 1, 2017, was applied prospectively and did not have a material impact on our consolidated balance sheet.

Derivatives and hedging

In March 2016, the FASB issued new guidance that clarifies the requirements for assessing whether contingent call or put options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. The new guidance requires only an assessment of the four-step decision sequence outlined in GAAP to determine whether the economic characteristics and risks of call or put options are clearly and closely related to the economic characteristics and risks of their debt hosts. This new guidance was effective January 1, 2017, was applied prospectively and has not resulted in any impact on our consolidated financial statements.

Equity method investments

In March 2016, the FASB issued new guidance that simplifies the transition to equity method accounting. The new guidance eliminates the requirement to retroactively apply the equity method of accounting when an increase in ownership interest in an investment qualifies it for equity method accounting. This new guidance was effective January 1, 2017, was applied prospectively and has not resulted in any impact on our consolidated financial statements.

Employee share-based payments

In March 2016, the FASB issued new guidance that simplifies several aspects of the accounting for employee share-based payment transactions, including income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. The new guidance also permits entities to make an accounting policy election either to continue to estimate the total number of awards for which the requisite service period will not be rendered or to account for forfeitures when they occur. We have elected to account for forfeitures when they occur. This new guidance was effective January 1, 2017 and resulted in a cumulative-effect adjustment of $12 million to retained earnings and the recognition of a deferred tax asset related to employee share-based payments that were made prior to the adoption of this guidance.

Consolidation

In October 2016, the FASB issued new guidance on consolidation relating to VIEs held through related parties that are under common control. The new guidance amends the consolidation requirements such that if a decision maker is required to evaluate whether it is the primary beneficiary of a VIE, it will need to consider only its proportionate indirect interest in the VIE held through a common control party. The new guidance was effective January 1, 2017, was applied retrospectively and did not result in any change to our consolidation conclusions.

Future accounting changes

Revenue from contracts with customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. The new guidance requires that an entity recognize revenue in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in an amount that reflects the total consideration to which it expects to be entitled during the term of the contract in exchange for those goods or services. The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue and the related cash flows. We will adopt the new guidance on the effective date of January 1, 2018. There are two methods in which the new guidance can be adopted: (1) a full retrospective approach with restatement of all prior periods presented, or (2) a modified retrospective approach with a cumulative-effect adjustment as of the date of adoption. We will adopt the guidance using the modified retrospective approach with the cumulative-effect of the adjustment, if any, recognized at the date of adoption, subject to allowable and elected practical expedients.

We identified all existing customer contracts that are within the scope of the new guidance by operating segment. We have completed our analysis of the contracts and have not identified any material differences in the amount and timing of revenue recognition as a result of implementing the new guidance. We will therefore, not require a cumulative-effect adjustment to opening retained earnings on January 1, 2018.

Although consolidated revenues will not be materially impacted by the new guidance, we will be required to add significant disclosures based on the prescribed requirements. These new disclosures will include information regarding the significant judgments used in evaluating when and how revenues, are recognized and information related to contract assets and deferred revenues. In addition, the new guidance requires that our revenue recognition policy disclosure includes additional detail regarding the various performance obligations and the nature, amount, timing and estimates of revenues and cash flows generated from contracts with customers. We have developed draft disclosures required in first quarter 2018 with a particular focus on the scope of contracts subject to disclosure of future revenues from remaining performance obligations. We have addressed system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance.

Financial instruments

In January 2016, the FASB issued new guidance on the accounting for equity investments and financial liabilities. The new guidance will change the income statement effect of equity investments and the recognition of changes in the fair value of financial liabilities when the fair value option is elected. The new guidance also requires us to assess valuation allowances for deferred tax assets related to available for sale debt securities in combination with their other deferred tax assets. This new guidance is effective January 1, 2018 and a method of adoption is specified for each component of the guidance. We have completed our analysis and do not expect the adoption of this guidance to have a material impact on our consolidated financial statements.

Leases

In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease requiring the lessor to have both (1) the right to obtain substantially all of the economic benefits from the use of the asset and (2) the right to direct the use of the asset in order for an arrangement to qualify as a lease. The new guidance also establishes a right-of-use (ROU) model that requires a lessee to recognize a ROU asset and corresponding lease liability on the balance sheet for all leases with a term longer than 12 months. Leases will be classified as finance or operating, with classification affecting the pattern of expense recognition in the income statement. The new guidance does not make extensive changes to lessor accounting.

The new guidance is effective January 1, 2019, with early adoption permitted. A modified retrospective transition approach is required for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. We are continuing to identify and analyze existing lease agreements to determine the effect of application of the new guidance on our consolidated financial statements. We are also addressing system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance and continue to monitor and analyze additional guidance and clarification provided by the FASB.

Measurement of credit losses on financial instruments

In June 2016, the FASB issued new guidance that significantly changes how entities measure credit losses for most financial assets and certain other financial instruments that are not measured at fair value through net income. The new guidance amends the impairment model of financial instruments basing it on expected losses rather than incurred losses. These expected credit losses will be recognized as an allowance rather than a direct write down of the amortized cost basis. The new guidance is effective January 1, 2020 and will be applied using a modified retrospective approach. We are currently evaluating the impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Income taxes

In October 2016, the FASB issued new guidance on the income tax effects of intra-entity transfers of assets other than inventory. The new guidance requires the recognition of deferred and current income taxes for an intra-entity asset transfer when the transfer occurs. The new guidance is effective January 1, 2018 and will be applied using a modified retrospective approach. We have completed our analysis and do not expect the application of this guidance to have a material impact on our consolidated financial statements.

Restricted cash

In November 2016, the FASB issued new guidance on restricted cash and cash equivalents on the statement of cash flows. The new guidance requires that the statement of cash flows explain the change during the period in the total cash and cash equivalents balance, and amounts generally described as restricted cash or restricted cash equivalents. Restricted cash and cash equivalents will be included with cash and cash equivalents when reconciling the beginning of year and end of year total amounts on the statement of cash flows. This new guidance is effective January 1, 2018 and will be applied retrospectively.

Goodwill impairment

In January 2017, the FASB issued new guidance on simplifying the test for goodwill impairment by eliminating Step 2 of the impairment test, which is the requirement to calculate the implied fair value of goodwill to measure the impairment charge. Instead, entities will record an impairment charge based on the excess of a reporting unit's carrying amount over its fair value. This new guidance is effective January 1, 2020 and will be applied prospectively, however, early adoption is permitted.

Employee post-retirement benefits

In March 2017, the FASB issued new guidance that will require entities to disaggregate the current service cost component from the other components of net benefit cost and present it with other current compensation costs for related employees in the income statement. The new guidance also requires that the other components of net benefit cost be presented elsewhere in the income statement and excluded from income from operations if such a subtotal is presented. In addition, the new guidance makes changes to the components of net benefit cost that are eligible for capitalization. Entities must use a retrospective transition method to adopt the requirement for separate presentation in the income statement of the components of net benefit cost, and a prospective transition method to adopt the change to capitalization of benefit costs. This new guidance is effective January 1, 2018. We have completed our analysis and do not expect the application of this guidance to have a material impact on our consolidated financial statements.

Amortization on purchased callable debt securities

In March 2017, the FASB issued new guidance that shortens the amortization period for the premium on certain purchased callable debt securities by requiring entities to amortize the premium to the earliest call date. This new guidance is effective January 1, 2019 and will be applied using a modified retrospective approach. We are currently evaluating the impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Hedge accounting

In August 2017, the FASB issued new guidance on hedge accounting, making more financial and non-financial hedging strategies eligible for hedge accounting. The new guidance also amends the presentation requirements relating to the change in fair value of a derivative and additional disclosure requirements include cumulative basis adjustments for fair value hedges and the effect of hedging on individual statement of income line items. This new guidance is effective January 1, 2019, with early adoption permitted. We have elected to apply this guidance effective January 1, 2018. We have completed our analysis and do not expect the application of this guidance to have a material impact on our consolidated financial statements.

RECONCILIATION OF COMPARABLE EBITDA AND COMPARABLE EBIT TO SEGMENTED EARNINGS

year ended December 31 (millions of $, except per share amounts)	2017	2016	2015
Comparable EBITDA			
Canadian Natural Gas Pipelines	**2,144**	2,182	2,216
U.S. Natural Gas Pipelines	**2,357**	1,682	970
Mexico Natural Gas Pipelines	**519**	332	213
Liquids Pipelines	**1,348**	1,152	1,308
Energy	**1,030**	1,281	1,254
Corporate	**(21)**	18	(53)
Comparable EBITDA	**7,377**	6,647	5,908
Depreciation and amortization	**(2,048)**	(1,939)	(1,765)
Comparable EBIT	**5,329**	4,708	4,143
Specific items:			
Energy East impairment charge	**(1,256)**	—	—
Integration and acquisition related costs – Columbia	**(91)**	(179)	—
Keystone XL asset costs	**(34)**	(52)	—
Net gain/(loss) on U.S. Northeast power assets	**484**	(844)	—
Gain on sale of Ontario solar assets	**127**	—	—
Foreign exchange gain – inter-affiliate loan	**63**	—	—
Ravenswood goodwill impairment	**—**	(1,085)	—
Alberta PPA terminations and settlement	**—**	(332)	—
Restructuring costs	**—**	(22)	(99)
TC Offshore loss on sale	**—**	(4)	(125)
Keystone XL impairment charge	**—**	—	(3,686)
Turbine equipment impairment charge	**—**	—	(59)
Bruce Power merger – debt retirement charge	**—**	—	(36)
Risk management activities[1]	**62**	123	(37)
Segmented earnings	**4,684**	2,313	101

1

year ended December 31 (millions of $)	2017	2016	2015
Canadian Power	**11**	4	(8)
U.S. Power	**39**	113	(30)
Liquids marketing	**—**	(2)	—
Natural Gas Storage	**12**	8	1
Total unrealized gains/(losses) from risk management activities	**62**	123	(37)

QUARTERLY RESULTS

Selected quarterly consolidated financial data

(unaudited, millions of $, except per share amounts)

2017	Fourth	Third	Second	First
Revenues	**3,617**	**3,224**	**3,217**	**3,391**
Net income attributable to common shares	**861**	**612**	**881**	**643**
Comparable earnings	**719**	**614**	**659**	**698**
Comparable earnings per common share	**$0.82**	**$0.70**	**$0.76**	**$0.81**
Share statistics				
Net income per common share – basic and diluted	**$0.98**	**$0.70**	**$1.01**	**$0.74**
Dividends declared per common share	**$0.625**	**$0.625**	**$0.625**	**$0.625**

2016	Fourth	Third	Second	First
Revenues	3,635	3,642	2,756	2,514
Net (loss)/income attributable to common shares	(358)	(135)	365	252
Comparable earnings	626	622	366	494
Comparable earnings per common share	$0.75	$0.78	$0.52	$0.70
Share statistics				
Net (loss)/income per common share – basic and diluted	($0.43)	($0.17)	$0.52	$0.36
Dividends declared per common share	$0.565	$0.565	$0.565	$0.565

Factors affecting quarterly financial information by business segment

Quarter-over-quarter revenues and net income fluctuate for reasons that vary across our business segments.

In our Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Mexico Natural Gas Pipelines segments, except for seasonal fluctuations in short-term throughput volumes on U.S. pipelines, quarter-over-quarter revenues and net income generally remain relatively stable during any fiscal year. Over the long term, however, they fluctuate because of:

- regulators' decisions
- negotiated settlements with shippers
- acquisitions and divestitures
- developments outside of the normal course of operations
- newly constructed assets being placed in service.

In Liquids Pipelines, annual revenues and net income are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income are affected by:

- developments outside of the normal course of operations
- newly constructed assets being placed in service
- regulatory decisions.

In Energy, quarter-over-quarter revenues and net income are affected by:

- weather
- customer demand
- market prices for natural gas and power
- capacity prices and payments
- planned and unplanned plant outages
- acquisitions and divestitures
- certain fair value adjustments
- developments outside of the normal course of operations
- newly constructed assets being placed in service.

Factors affecting financial information by quarter

We calculate comparable measures by adjusting certain GAAP and non-GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period.

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

In fourth quarter 2017, comparable earnings excluded:

- an $804 million recovery of deferred income taxes as a result of U.S. Tax Reform
- a $136 million after-tax gain related to the sale of our Ontario solar assets
- a $64 million net after-tax gain related to the monetization of our U.S. Northeast power business, which included an incremental after-tax loss of $7 million recorded on the sale of the thermal and wind package, $23 million of after-tax third-party insurance proceeds related to a 2017 Ravenswood outage and income tax adjustments
- a $954 million after-tax impairment charge for the Energy East pipeline and related projects as a result of our decision not to proceed with the project applications
- a $9 million after-tax charge related to the maintenance and liquidation of Keystone XL assets which were expensed pending further advancement of the project.

In third quarter 2017, comparable earnings excluded:

- an incremental net loss of $12 million related to the monetization of our U.S. Northeast power business which included an incremental loss of $7 million after tax on the sale of the thermal and wind package and $14 million of after-tax disposition costs and income tax adjustments
- an after-tax charge of $30 million for integration-related costs associated with the acquisition of Columbia
- an after-tax charge of $8 million related to the maintenance of Keystone XL assets which were being expensed pending further advancement of the project.

In second quarter 2017, comparable earnings excluded:

- a $265 million net after-tax gain related to the monetization of our U.S. Northeast power business which included a $441 million after-tax gain on the sale of TC Hydro and a loss of $176 million after tax on the sale of the thermal and wind package
- an after-tax charge of $15 million for integration-related costs associated with the acquisition of Columbia
- an after-tax charge of $4 million related to the maintenance of Keystone XL assets which were being expensed pending further advancement of the project.

In first quarter 2017, comparable earnings excluded:

- a charge of $24 million after tax for integration-related costs associated with the acquisition of Columbia
- a charge of $10 million after tax for costs related to the monetization of our U.S. Northeast power business
- a charge of $7 million after tax related to the maintenance of Keystone XL assets which were being expensed pending further advancement of the project
- a $7 million income tax recovery related to the realized loss on a third party sale of Keystone XL project assets. A provision for the expected pre-tax loss on these assets was included in our 2015 impairment charge, but the related income tax recoveries could not be recorded until realized.

In fourth quarter 2016, comparable earnings excluded:

- an $870 million after-tax charge related to the loss on U.S. Northeast power assets held for sale which included an $863 million after-tax loss on the thermal and wind package held for sale and $7 million of after-tax costs related to the monetization
- an additional $68 million after-tax loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the Alberta PPA terminations
- an after-tax charge of $67 million for costs associated with the acquisition of Columbia which included a $44 million deferred tax adjustment upon acquisition and $23 million of retention, severance and integration costs
- an after-tax charge of $18 million related to Keystone XL costs for the maintenance and liquidation of project assets which were being expensed pending further advancement of the project
- an after-tax restructuring charge of $6 million for additional expected future losses under lease commitments. These charges formed part of a restructuring initiative, which commenced in 2015, to maximize the effectiveness and efficiency of our existing operations and reduce overall costs.

In third quarter 2016, comparable earnings excluded:

- a $656 million after-tax impairment on the Ravenswood goodwill. As a result of information received during the process to monetize our U.S. Northeast power business in third quarter 2016, it was determined that the fair value of Ravenswood no longer exceeded its carrying value
- costs associated with the acquisition of Columbia including a charge of $67 million after tax primarily relating to retention, severance and integration expenses
- $28 million of income tax recoveries related to the realized loss on a third party sale of Keystone XL plant and equipment. A provision for the expected loss on these assets was included in our fourth quarter 2015 impairment charge but the related tax recoveries could not be recorded until realized
- a charge of $9 million after tax related to Keystone XL costs for the maintenance and liquidation of project assets which were being expensed pending further advancement of the project
- a $3 million after-tax charge related to the monetization of our U.S. Northeast power business.

In second quarter 2016, comparable earnings excluded:

- a charge of $113 million related to costs associated with the acquisition of Columbia which included $109 million related to dividend equivalent payments on the subscription receipts
- a charge of $9 million after tax related to Keystone XL costs for the maintenance and liquidation of project assets which were being expensed pending further advancement of the project
- a charge of $10 million after tax for restructuring charges mainly related to expected future losses under lease commitments.

In first quarter 2016, comparable earnings excluded:

- a $176 million after-tax impairment charge on the carrying value of our Alberta PPAs as a result of our decision to terminate the PPAs
- a charge of $26 million related to costs associated with the acquisition of Columbia
- a charge of $6 million after tax related to Keystone XL costs for the maintenance and liquidation of project assets which were being expensed pending further advancement of the project
- an additional $3 million after-tax loss on the sale of TC Offshore which closed on March 31, 2016.

FOURTH QUARTER 2017 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	2017	2016
Canadian Natural Gas Pipelines	**333**	364
U.S. Natural Gas Pipelines	**461**	403
Mexico Natural Gas Pipelines	**93**	103
Liquids Pipelines	**(932)**	213
Energy	**472**	(574)
Corporate	**63**	(33)
Total segmented earnings	**490**	476
Interest expense	**(541)**	(542)
Allowance for funds used during construction	**140**	97
Interest income and other	**(9)**	(15)
Income before income taxes	**80**	16
Income tax recovery/(expense)	**870**	(274)
Net income/(loss)	**950**	(258)
Net income attributable to non-controlling interests	**(49)**	(68)
Net income/(loss) attributable to controlling interests	**901**	(326)
Preferred share dividends	**(40)**	(32)
Net income/(loss) attributable to common shares	**861**	(358)
Net income/(loss) per common share – basic and diluted	**$0.98**	($0.43)

Net income/(loss) attributable to common shares increased by $1,219 million or $1.41 per share for the three months ended December 31, 2017 compared to the same period in 2016 due to the changes in net income described below, as well as the dilutive effect of issuing 60 million common shares in the fourth quarter of 2016 and common shares issued under our DRP and corporate ATM program in 2017.

Fourth quarter 2017 results included:

- an $804 million recovery of deferred income taxes as a result of U.S. Tax Reform
- a $136 million after-tax gain related to the sale of our Ontario solar assets
- a $64 million net after-tax gain related to the monetization of our U.S. Northeast power business, which included an incremental after-tax loss of $7 million recorded on the sale of the thermal and wind package, $23 million of after-tax third-party insurance proceeds related to a 2017 Ravenswood outage and income tax adjustments
- a $954 million after-tax impairment charge for the Energy East pipeline and related projects as a result of our decision not to proceed with the project applications
- a $9 million after-tax charge related to the maintenance and liquidation of Keystone XL assets which were expensed pending further advancement of the project.

Fourth quarter 2016 results included:

- an $870 million after-tax charge related to the loss on U.S. Northeast power assets held for sale which included an $863 million after-tax loss on the thermal and wind package held for sale and $7 million of after-tax costs related to the monetization
- an additional $68 million after-tax loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the Alberta PPA terminations
- an after-tax charge of $67 million for costs associated with the acquisition of Columbia which included a $44 million deferred tax adjustment upon closing of the acquisition and $23 million of retention, severance and integration costs
- an $18 million after-tax charge related to the maintenance and liquidation of Keystone XL assets which were expensed pending further advancement of the project
- an after-tax restructuring charge of $6 million for additional expected future losses under lease commitments. These charges form part of a restructuring initiative, which commenced in 2015, to maximize the effectiveness and efficiency of our existing operations and reduce overall costs.

Net income/(loss) in both periods included unrealized gains and losses from changes in risk management activities which we exclude, along with the above-noted items, to arrive at comparable earnings.

Reconciliation of net income/(loss) to comparable earnings

three months ended December 31 (millions of $, except per share amounts)	2017	2016
Net income/(loss) attributable to common shares	**861**	(358)
Specific items (net of tax):		
U.S. Tax Reform adjustment	**(804)**	—
Gain on sale of Ontario solar assets	**(136)**	—
Net (gain)/loss on sales of U.S. Northeast power assets	**(64)**	870
Energy East impairment charge	**954**	—
Keystone XL asset costs	**9**	18
Alberta PPA terminations and settlement	**—**	68
Acquisition related costs – Columbia	**—**	67
Restructuring costs	**—**	6
Risk management activities[1]	**(101)**	(45)
Comparable earnings	**719**	626
Net income/(loss) per common share	**$0.98**	($0.43)
Specific items (net of tax):		
U.S. Tax Reform adjustment	**(0.92)**	—
Gain on sale of Ontario solar assets	**(0.16)**	—
Net (gain)/loss on sales of U.S. Northeast power assets	**(0.08)**	1.05
Energy East impairment charge	**1.09**	—
Keystone XL asset costs	**0.01**	0.02
Alberta PPA terminations and settlement	**—**	0.08
Acquisition related costs – Columbia	**—**	0.08
Restructuring costs	**—**	0.01
Risk management activities	**(0.10)**	(0.06)
Comparable earnings per common share	**$0.82**	$0.75

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three months ended December 31 (millions of $)	2017	2016
Canadian Power	**6**	1
U.S. Power	**136**	97
Liquids marketing	**15**	4
Natural Gas Storage	**7**	(1)
Foreign exchange	**(1)**	(23)
Income tax attributable to risk management activities	**(62)**	(33)
Total unrealized gains from risk management activities	**101**	45

Comparable earnings

Comparable earnings increased by $93 million or $0.07 per share for the three months ended December 31, 2017 compared to the same period in 2016 and was primarily the net effect of:

- increased earnings from Liquids Pipelines primarily due to higher uncontracted volumes on the Keystone Pipeline System, liquids marketing activities, and the commencement of operations on new intra-Alberta pipelines Grand Rapids and Northern Courier
- higher contribution from U.S. Natural Gas Pipelines due to lower operating costs including synergies achieved from the Columbia acquisition
- higher AFUDC on our rate-regulated U.S. natural gas pipelines, partially offset by our decision not to proceed with the Energy East Pipeline
- higher earnings from Bruce Power mainly due to higher volumes resulting from fewer outage days
- lower contribution from U.S. Power due to the monetization of our U.S. Northeast power generation assets in second quarter 2017 and the continued wind-down of our U.S. power marketing operations
- an after-tax impairment charge in 2017 of $16 million related to obsolete Energy equipment.

Highlights by business segment

Canadian Natural Gas Pipelines

Canadian Natural Gas Pipelines segmented earnings decreased by $31 million for the three months ended December 31, 2017 compared to the same period in 2016 and are equivalent to comparable EBIT.

Net income for the NGTL System increased by $6 million for the three months ended December 31, 2017 compared to the same period in 2016 mainly due to a higher average investment base, partially offset by lower OM&A incentive earnings.

Canadian Mainline's net income decreased by $4 million for the three months ended December 31, 2017 compared to the same period in 2016 primarily due to a lower average investment base and lower incentive earnings.

Depreciation and amortization increased by $16 million for the three months ended December 31, 2017 compared to the same period in 2016 mainly due to facilities that were placed in service for the NGTL System and Canadian Mainline.

U.S. Natural Gas Pipelines

U.S. Natural Gas Pipelines segmented earnings increased by $58 million for the three months ended December 31, 2017 compared to the same period in 2016. Segmented earnings for the three months ended December 31, 2016 included pre-tax costs of $11 million mainly related to retention and severance expenses resulting from the Columbia acquisition, which has been excluded from our calculation of comparable EBIT.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$45 million for the three months ended December 31, 2017 compared to the same period in 2016. This was primarily due to lower operating costs including synergies achieved from the Columbia acquisition.

Depreciation and amortization decreased by US$5 million for the three months ended December 31, 2017 compared to the same period in 2016 primarily due to fair value adjustments related to our Midstream assets recorded in fourth quarter 2016.

Mexico Natural Gas Pipelines

Mexico Natural Gas Pipelines segmented earnings decreased by $10 million for the three months ended December 31, 2017 compared to the same period in 2016 and are equivalent to comparable EBIT. Aside from the commercial factors outlined below, a weaker U.S. dollar had a negative impact on the Canadian dollar equivalent segmented earnings from our Mexico operations.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$5 million for the three months December 31, 2017 compared to the same period in 2016 and was the net effect of:

- incremental earnings from Mazatlán beginning December 2016
- equity earnings from our investment in the Sur de Texas pipeline which records AFUDC during construction, net of interest expense on an inter-affiliate loan from TransCanada. The inter-affiliate loan interest is fully offset in interest income and other in the Corporate segment.

Depreciation and amortization increased by US$6 million for the three months ended December 31, 2017 compared to the same period in 2016 primarily due to the commencement of depreciation on Mazatlán.

Liquids Pipelines

Liquids Pipelines segmented earnings decreased by $1,145 million for the three months ended December 31, 2017 compared to the same period in 2016. This was primarily the net effect of a $1,256 million pre-tax impairment charge for the Energy East pipeline, $11 million (2016 – $15 million) of pre-tax costs related to Keystone XL for the maintenance and liquidation of project assets which were expensed pending further advancement of the project, and unrealized gains from changes in the fair value of derivatives related to our liquids marketing business. These amounts have been excluded from our calculation of comparable EBIT.

Comparable EBITDA for Liquids Pipelines increased by $99 million for the three months ended December 31, 2017 compared to the same period in 2016 and was the net effect of:

- higher uncontracted volumes on the Keystone Pipeline System
- new intra-Alberta pipelines, Grand Rapids and Northern Courier, which began operations in the second half of 2017
- a higher contribution from the liquids marketing business
- higher business development activities, including advancement of Keystone XL
- a weaker U.S. dollar which had a negative impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

Depreciation and amortization increased by $3 million for the three months ended December 31, 2017 compared to the same period in 2016 as a result of the new facilities being placed in-service, partially offset by the effect of a weaker U.S. dollar.

Energy

Energy segmented earnings increased by $1,046 million for the three months ended December 31, 2017 compared to the same period in 2016 and included the following specific items:

- a gain in 2017 of $127 million before tax related to the sale of our Ontario solar assets
- a net gain in 2017 of $15 million before tax related to the monetization of our U.S. Northeast power assets which consisted primarily of insurance recoveries for a portion of repair costs incurred during an unplanned outage at Ravenswood prior to its sale
- in 2016, a loss of $839 million before tax related to the sale of the U.S. Northeast power assets which included an $829 million pre-tax loss on the thermal and wind package and $10 million of pre-tax disposition costs
- in 2016, a $92 million before tax loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the Alberta PPA terminations
- unrealized gains and losses in both years from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks.

The remainder of the Energy segmented earnings are equivalent to comparable EBIT along with comparable EBITDA.

Corporate

Corporate segmented earnings were $63 million for the three months ended December 31, 2017 compared to a loss of $33 million for the same period in 2016 and included the following specific items that have been excluded from comparable EBIT:

- in 2017, a foreign exchange gain on a peso-denominated inter-affiliate loan to the Sur de Texas project for our proportionate share of the project's financing. There is a corresponding foreign exchange loss included in interest income and other on the inter-affiliate loan receivable which fully offsets this gain
- in 2016, pre-tax integration and acquisition costs associated with the acquisition of Columbia and restructuring costs.

Comparable EBITDA decreased by $12 million for the three months ended December 31, 2017 compared to the same period in 2016 primarily due to increased general and administrative costs.

Glossary

Units of measure

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

General terms and terms related to our operations

ATM	An at-the-market program allowing us to issue common shares from treasury at the prevailing market price
bitumen	A thick, heavy oil that must be diluted to flow (also see: diluent). One of the components of the oil sands, along with sand, water and clay
cogeneration facilities	Facilities that produce both electricity and useful heat at the same time
diluent	A thinning agent made up of organic compounds. Used to dilute bitumen so it can be transported through pipelines
Empress	A major delivery/receipt point for natural gas near the Alberta/ Saskatchewan border
FID	Final investment decision
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it
GHG	Greenhouse gas
HSE	Health, safety and environment
investment base	Includes rate base as well as assets under construction
LDC	Local distribution company
LNG	Liquefied natural gas
MLP	Master limited partnership
OM&A	Operating, maintenance and administration
PPA	Power purchase arrangement
rate base	Our annual average investment used
TSA	Transportation Service Agreements
WCSB	Western Canada Sedimentary Basin

Accounting terms

AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive (loss)/income
ARO	Asset retirement obligations
DRP	Dividend reinvestment plan
GAAP	U.S. generally accepted accounting principles
FASB	Financial Accounting Standards Board (U.S.)
OCI	Other comprehensive (loss)/income
RRA	Rate-regulated accounting
ROE	Rate of return on common equity
Specific Item	Items we believe are significant but not reflective of our underlying operations in the period

Government and regulatory bodies terms

AER	Alberta Energy Regulator
CFE	Comisión Federal de Electricidad (Mexico)
CRE	Comisión Reguladora de Energia, or Energy Regulatory Commission (Mexico)
FERC	Federal Energy Regulatory Commission (U.S.)
IESO	Independent Electricity System Operator
ISO	Independent System Operator
NAFTA	North American Free Trade Agreement
NEB	National Energy Board (Canada)
OPEC	Organization of the Petroleum Exporting Countries
OPG	Ontario Power Generation
SEC	U.S. Securities and Exchange Commission
SGER	Specified Gas Emitters Regulations