Management's discussion and analysis

February 12, 2020

On May 3, 2019, TransCanada Corporation changed its name to TC Energy Corporation (TC Energy) to better reflect the scope of our operations as a leading North American energy infrastructure company.

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TC Energy Corporation. It discusses our business, operations, financial position, risks and other factors for the year ended December 31, 2019.

This MD&A should be read with our accompanying December 31, 2019 audited Consolidated financial statements and notes for the same period, which have been prepared in accordance with U.S. GAAP.

Contents

About this document

Throughout this MD&A, the terms ***we***, ***us***, ***our*** and ***TC Energy*** mean TC Energy Corporation and its subsidiaries. Abbreviations and acronyms that are not defined in the document are defined in the glossary on page 106. All information is as of February 12, 2020 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:
- our financial and operational performance, including the performance of our subsidiaries
- expectations about strategies and goals for growth and expansion
- expected cash flows and future financing options available, including portfolio management
- expected dividend growth
- expected access to and cost of capital
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures, contractual obligations, commitments and contingent liabilities
- expected regulatory processes and outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- the expected impact of future tax and accounting changes
- 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

- regulatory decisions and outcomes
- planned and unplanned outages and the use of our pipeline, power and storage assets
- integrity and reliability of our assets
- anticipated construction costs, schedules and completion dates
- access to capital markets, including portfolio management
- expected industry, market and economic conditions
- inflation rates and commodity prices
- interest, tax and foreign exchange rates
- nature and scope of hedging.

Risks and uncertainties

- our ability to successfully implement our strategic priorities and whether they will yield the expected benefits
- our ability to implement a capital allocation strategy aligned with maximizing shareholder value
- the operating performance of our pipeline, power and storage assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the amount of capacity payments and revenues from our power generation assets due to plant availability
- production levels within supply basins
- construction and completion of capital projects
- costs for labour, equipment and materials
- the availability and market prices of commodities
- access to capital markets on competitive terms
- interest, tax and foreign exchange rates
- performance and credit risk of our counterparties
- regulatory decisions and outcomes of legal proceedings, including arbitration and insurance claims
- our ability to effectively anticipate and assess changes to government policies and regulations, including those related to the environment
- competition in the businesses in which we operate
- unexpected or unusual weather
- acts of civil disobedience
- cyber security and technological developments
- economic conditions in North America as well as globally.

You can read more about these factors and others in this MD&A and in other 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 TC Energy in our Annual Information Form (AIF) 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 EBITDA
- comparable EBIT
- comparable earnings
- comparable earnings per common share
- funds generated from operations
- comparable funds generated from operations.

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

Comparable measures

We calculate comparable measures by adjusting certain 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:

- gains or losses on sales of assets or assets held for sale
- income tax refunds and adjustments to enacted tax rates
- certain fair value adjustments relating to risk management activities
- legal, contractual and bankruptcy settlements
- impairment of goodwill, investments and other assets
- acquisition and integration costs
- restructuring 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 most directly comparable GAAP measures.

Comparable measure	GAAP measure
comparable EBITDA	segmented earnings
comparable EBIT	segmented earnings
comparable earnings	net income attributable to common shares
comparable earnings per common share	net income per common share
comparable funds generated from operations	net cash provided by operations

Comparable EBITDA and comparable EBIT

Comparable EBITDA represents segmented earnings adjusted for certain specific items, excluding non-cash charges for depreciation and amortization. We use comparable EBITDA as a measure of our earnings from ongoing operations as it is a useful indicator of our performance and is also presented on a consolidated basis. Comparable EBIT represents segmented earnings adjusted for specific items. Comparable EBIT is an effective tool for evaluating trends in each segment. Refer to the business segments Financial results sections for a reconciliation to segmented earnings.

Comparable earnings and comparable earnings per common share

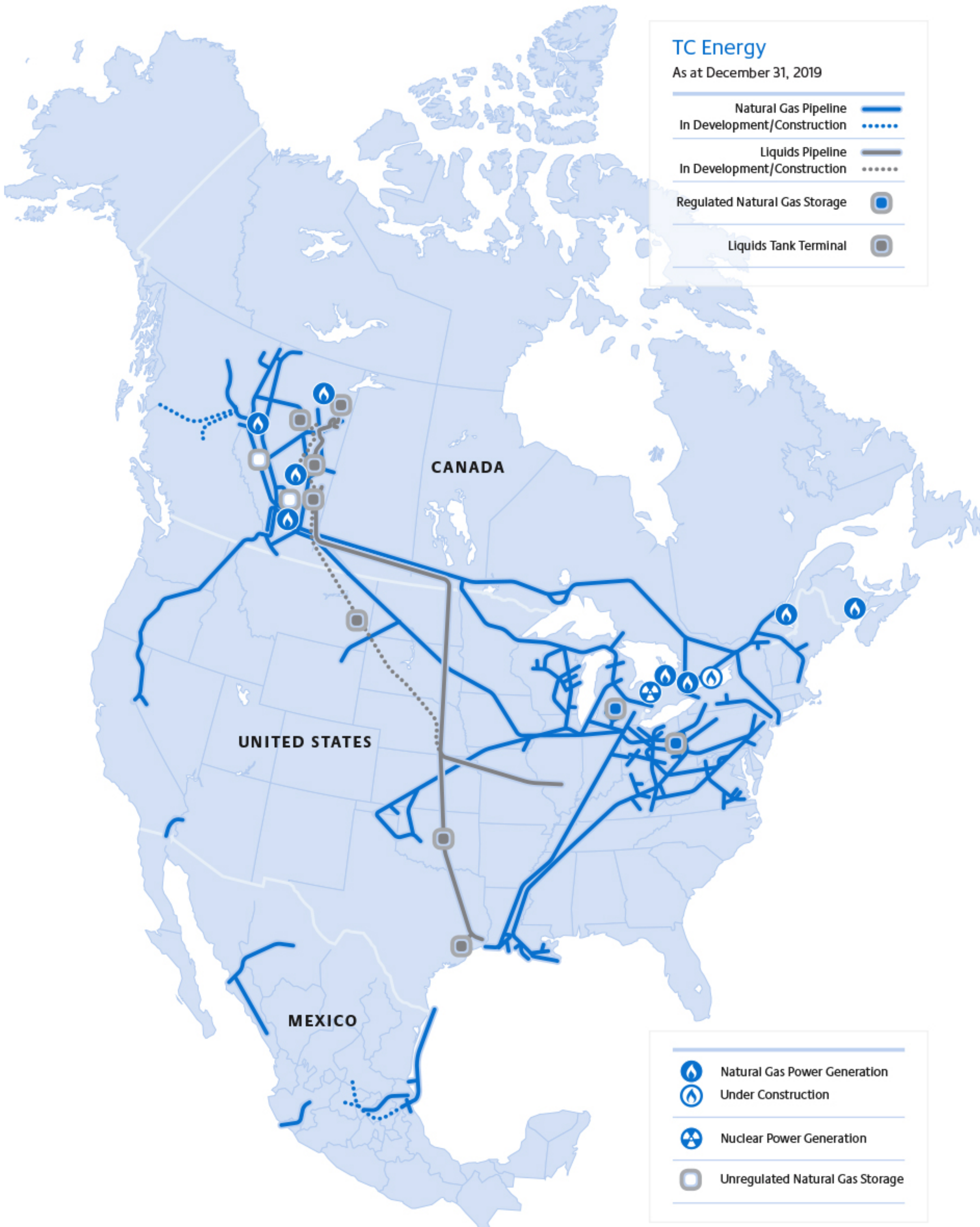
Comparable earnings represents earnings or losses attributable to common shareholders on a consolidated basis, adjusted for specific items. Comparable earnings is comprised of segmented earnings, Interest expense, AFUDC, Interest income and other, Income tax expense, Non-controlling interests and Preferred share dividends, adjusted for specific items. Refer to the Financial highlights section for reconciliations to Net income attributable to common shares and Net income per common share.

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 flows 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. Refer to the Financial condition section for a reconciliation to net cash provided by operations.

About our business

With over 65 years of experience, TC Energy 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 Power and Storage. In order to provide information that is aligned with how management decisions about our businesses are made and how performance of our businesses 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 Power and Storage. We also have a Corporate segment consisting of corporate and administrative functions that provide governance, financing and other support to TC Energy's business segments.

Year at-a-glance

at December 31 (millions of $)	2019	2018
Total assets by segment		
Canadian Natural Gas Pipelines	**21,983**	18,407
U.S. Natural Gas Pipelines[1]	**41,627**	44,115
Mexico Natural Gas Pipelines	**7,207**	7,058
Liquids Pipelines[2]	**15,931**	17,352
Power and Storage[3]	**7,788**	8,475
Corporate	**4,743**	3,513
	99,279	98,920

1 Includes Columbia midstream assets in 2018, which were sold on August 1, 2019.
2 Reflects the sale of an 85 per cent equity interest in Northern Courier on July 17, 2019.
3 Includes Coolidge generating station in 2018, which was sold on May 21, 2019.

year ended December 31 (millions of $)	2019	2018
Total revenues by segment		
Canadian Natural Gas Pipelines	**4,010**	4,038
U.S. Natural Gas Pipelines[1]	**4,978**	4,314
Mexico Natural Gas Pipelines	**603**	619
Liquids Pipelines[2]	**2,879**	2,584
Power and Storage[3]	**785**	2,124
	13,255	13,679

1 Includes Columbia midstream assets until sold on August 1, 2019.
2 Reflects the sale of an 85 per cent equity interest in Northern Courier on July 17, 2019.
3 Includes Coolidge generating station until sold on May 21, 2019 and Cartier Wind assets until sold in October 2018.

year ended December 31 (millions of $)	2019	2018
Comparable EBITDA by segment		
Canadian Natural Gas Pipelines	**2,274**	2,379
U.S. Natural Gas Pipelines[1]	**3,480**	3,035
Mexico Natural Gas Pipelines	**605**	607
Liquids Pipelines[2]	**2,192**	1,849
Power and Storage[3]	**832**	752
Corporate	**(17)**	(59)
	9,366	8,563

1 Includes Columbia midstream assets until sold on August 1, 2019.
2 Reflects the sale of an 85 per cent equity interest in Northern Courier on July 17, 2019.
3 Includes Coolidge generating station until sold on May 21, 2019 and Cartier Wind assets until sold in October 2018.

OUR STRATEGY

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

Our business is made up of pipeline and storage assets that transport, store or deliver natural gas and crude oil as well as power generation assets that produce electricity to support businesses and communities across the continent. Leveraging the key components of our strategy, highlighted below, we have decades of experience managing our portfolio to capitalize on opportunities and mitigate risks (refer to the Enterprise risk management section).

Key components of our strategy

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

- Long-life infrastructure assets covering strategic North American corridors and supported by 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 and associated storage facilities that connect low cost supply basins with stable and growing North American and export markets, generating predictable and sustainable cash flows and earnings
- Our power and non-regulated storage assets are primarily under long-term contracts that provide stable cash flows and earnings.

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

- We are developing high quality, long-life assets under our current capital program, comprised of $30 billion in secured projects and $21 billion in largely commercially-supported projects under development. These investments will contribute incremental earnings and cash flows as they are placed in service
- Our existing extensive footprint offers replenishable growth opportunities
- 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 our experience and our regulatory, commercial, financial, legal and operational expertise to successfully permit, fund, build and integrate new pipeline and other energy facilities
- Safety, profitability and responsible ESG performance are fundamental to our investments.

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, considers future resilience, and diversifies access to attractive supply and market regions within our risk tolerance profile. Refer to the Enterprise risk management section for additional information
- We focus on commercially regulated and/or long-term contracted 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
- We monitor trends specific to energy supply and demand fundamentals, in addition to analyzing how our portfolio performs under different energy scenarios considering the recommendations of the Task Force on Climate-related Financial Disclosures (TCFD). These results contribute to the identification of opportunities to maintain our resilience, strengthen our asset base or seek diversification, if required.

4	**Maximize our competitive strengths**

- We are continually refining core competencies in key sustainability and ESG areas such as safety, operational excellence, supply chain management, project execution and stakeholder relations to ensure we deliver maximum shareholder value over the short, medium and long terms.

Our competitive advantage

Decades of experience in the energy infrastructure business and a disciplined approach to project management and capital investment give us our competitive edge while remaining focused on our purpose: to deliver the energy people need every day, safely, responsibly, collaboratively and with integrity.

- strong leadership and governance: we maintain rigorous governance over our approach to business ethics, enterprise risk management, competitive behaviour, operating capabilities and strategy development, as well as regulatory, legal, commercial and financing support
- a high-quality portfolio: our low-risk and enduring business model offers the scale and presence to maximize the full-life value of our long-life assets and commercial positions throughout all points of the business cycle
- disciplined operations: our values-centred workforce is highly skilled in designing, building and operating energy infrastructure with a focus on operational excellence and a commitment to health, safety, sustainability and the environment
- financial positioning: we exhibit consistently strong financial performance, long-term financial stability and profitability, and a disciplined approach to capital investment. We can access sizable amounts of competitively-priced capital to support our growth and balance common share dividend growth while preserving financial flexibility to fund our capital program in all market conditions. In addition, we continue to maintain the simplicity and understandability of our business and corporate structure
- commitment to sustainability and ESG: we take a long-term view to managing our interactions with the environment, Indigenous groups, community members and landowners. We aim to communicate transparently on sustainability-related issues with all stakeholders
- open communication: we carefully manage relationships with our customers and shareholders and offer clear communication of our prospects to investors – both the upside and the downside risks – to build trust and support.

Our risk preferences

The following is an overview of our risk philosophy:

Live within our means

- Rely on internally-generated cash flows, existing debt capacity, partnerships and portfolio management to finance new initiatives. Reserve common equity issuances for transformational opportunities.

Project risks known and acceptable

- Select investments with known, acceptable and manageable project execution risk, including sustainability considerations.

Business underpinned by strong fundamentals

- Invest in assets that are investment-grade on a stand-alone basis, with stable cash flows, supported by strong underlying macroeconomic fundamentals, conducive regulations and/or long-term contracts with creditworthy counterparties.

Manage credit metrics to ensure "top-end" sector ratings

- Solid investment-grade ratings are an important competitive advantage and TC Energy will seek to ensure its ratings are in the top-end of its sector while balancing the interests of equity and fixed income investors.

Prudent management of counterparty exposure

- Limit counterparty concentration and sovereign risk; seek diversification and solid commercial arrangements underpinned by strong fundamentals.

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 and/or regulated business models and are expected to generate significant growth in earnings and cash flows.

Our capital program consists of approximately $30 billion of secured projects which include commercially-supported, committed projects that are either under construction or are in or preparing to commence the permitting stage. An additional $21 billion of projects under development are commercially supported (except where noted) but have greater uncertainty with respect to timing and estimated project costs and remain subject to certain key approvals.

Three years of maintenance capital expenditures for our businesses are included in secured projects. Maintenance capital expenditures on our regulated Canadian and U.S. natural gas pipeline businesses are added to rate base on which we have the opportunity to earn a return and recover these expenditures through current or future tolls, which is similar to our capacity capital projects on these pipelines. Tolling arrangements in our liquids pipelines business provide for the recovery of maintenance capital expenditures.

In 2019, we placed approximately $8.7 billion of capacity projects in service including Mountaineer XPress, Gulf XPress, NGTL System expansions and the Sur de Texas and White Spruce pipelines. In addition, approximately $2 billion of maintenance capital expenditures were incurred.

All projects are subject to cost and timing adjustments due to weather, market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits, among other factors. Amounts presented in the following tables exclude capitalized interest and AFUDC.

Secured projects

(billions of $)	Expected in-service date	Estimated project cost[1]	Carrying value at December 31, 2019
Canadian Natural Gas Pipelines			
Canadian Mainline	2020-2023	0.4	0.1
NGTL System[2]	2020	3.4	2.5
	2021	2.6	0.2
	2022	1.8	—
	2023+	1.5	—
Coastal GasLink[3,4]	2023	6.6	1.2
Regulated maintenance capital expenditures	2020-2022	1.9	—
U.S. Natural Gas Pipelines			
Modernization II (Columbia Gas)	2020	US 1.1	US 0.7
Other capacity capital	2020-2023	US 1.5	US 0.1
Regulated maintenance capital expenditures	2020-2022	US 2.1	—
Mexico Natural Gas Pipelines			
Villa de Reyes	2020	US 0.9	US 0.8
Tula[5]	—	US 0.8	US 0.6
Liquids Pipelines			
Other capacity capital	2020	0.1	—
Recoverable maintenance capital expenditures	2020-2022	0.1	—
Power and Storage			
Bruce Power – life extension[6]	2020-2023	2.4	0.8
Other			
Non-recoverable maintenance capital expenditures[7]	2020-2022	0.4	—
		27.6	**7.0**
Foreign exchange impact on secured projects[8]		**1.9**	**0.7**
Total secured projects (Cdn$)		**29.5**	**7.7**

1 Amounts reflect 100 per cent of costs related to wholly-owned assets and assets held through TC PipeLines, LP, as well as cash contributions to our joint venture investments.

2 Includes $0.6 billion for the Foothills pipeline system related to the West Path Delivery Program.

3 Represents 100 per cent of Coastal GasLink required capital prior to the impact of the announced joint venture partnership and expected project-level financing.

4 Carrying value is net of the 2018 receipts from the LNG Canada participants for the reimbursement of approximately $0.5 billion of pre-FID costs pursuant to project agreements.

5 Construction of the central segment for the Tula project has been delayed due to a lack of progress to successfully complete Indigenous consultation by the Secretary of Energy. Project completion is expected approximately two years after the consultation process is successfully concluded. The East Section of the Tula pipeline is available for interruptible transportation services.

6 Reflects our proportionate share of the Unit 6 Major Component Replacement program costs, expected to be in service in 2023, and amounts to be invested under the Asset Management program through 2023.

7 Includes non-recoverable maintenance capital expenditures from all segments and is primarily comprised of our proportionate share of maintenance capital expenditures for Bruce Power and other Power and Storage assets.

8 Reflects U.S./Canada foreign exchange rate of 1.30 at December 31, 2019.

Projects under development

The costs provided in the table below reflect the most recent estimates for each project as filed with the various regulatory authorities or as otherwise determined by management.

(billions of $)	Estimated project cost[1]	Carrying value at December 31, 2019
Canadian Natural Gas Pipelines		
NGTL System – Merrick	1.9	—
U.S. Natural Gas Pipelines		
Other capacity capital[2]	US 0.7	—
Liquids Pipelines		
Keystone XL[3]	US 8.0	US 1.1
Heartland and TC Terminals[4]	0.9	0.1
Grand Rapids Phase II[4]	0.7	—
Keystone Hardisty Terminal[4]	0.3	0.1
Power and Storage		
Bruce Power – life extension[5]	5.8	0.1
	18.3	**1.4**
Foreign exchange impact on projects under development[6]	**2.6**	**0.3**
Total projects under development (Cdn$)	**20.9**	**1.7**

1 Amounts reflect our proportionate share of joint venture costs where applicable and 100 per cent of costs related to wholly-owned assets and assets held through TC Pipelines, LP.

2 Includes projects subject to a positive customer FID.

3 Carrying value reflects amount remaining after the 2015 impairment charge, along with additional amounts capitalized from January 2018. A portion of the carrying value is recoverable from shippers under certain conditions.

4 Regulatory approvals have been obtained and additional commercial support is being pursued.

5 Reflects our proportionate share of Major Component Replacement program costs for Units 3, 4, 5, 7 and 8, and the remaining Asset Management program costs beyond 2023.

6 Reflects U.S./Canada foreign exchange rate of 1.30 at December 31, 2019.

2019 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 comparable to similar 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 and comparable funds generated from operations are all non-GAAP measures. Refer to page 8 for more information about the non-GAAP measures we use and pages 20 and 72 as well as the business segment Financial results sections for reconciliations to the most directly comparable GAAP measures.

year ended December 31 (millions of $, except per share amounts)	**2019**	**2018**	**2017**
Income			
Revenues	**13,255**	13,679	13,449
Net income attributable to common shares	**3,976**	3,539	2,997
per common share – basic	**$4.28**	$3.92	$3.44
– diluted	**$4.27**	$3.92	$3.43
Comparable EBITDA	**9,366**	8,563	7,377
Comparable earnings	**3,851**	3,480	2,690
per common share	**$4.14**	$3.86	$3.09
Cash flows			
Net cash provided by operations	**7,082**	6,555	5,230
Comparable funds generated from operations	**7,117**	6,522	5,641
Capital spending[1]	**8,784**	10,929	9,210
Proceeds from sales of assets, net of transaction costs	**2,398**	614	4,683
Reimbursement of costs related to capital projects in development	**—**	470	634
Balance sheet			
Total assets	**99,279**	98,920	86,101
Long-term debt	**36,985**	39,971	34,741
Junior subordinated notes	**8,614**	7,508	7,007
Preferred shares	**3,980**	3,980	3,980
Non-controlling interests	**1,634**	1,655	1,852
Common shareholders' equity	**26,783**	25,358	21,059
Dividends declared[2]			
per common share	**$3.00**	$2.76	$2.50
Basic common shares (millions)			
– weighted average for the year	**929**	902	872
– issued and outstanding at end of year	**938**	918	881

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

2 Refer to the Financial condition section on page 71 for details on common and preferred share dividends.

Consolidated results

year ended December 31 (millions of $, except per share amounts)	2019	2018	2017
Segmented earnings/(losses)			
Canadian Natural Gas Pipelines	**1,115**	1,250	1,236
U.S. Natural Gas Pipelines	**2,747**	1,700	1,760
Mexico Natural Gas Pipelines	**490**	510	426
Liquids Pipelines	**1,848**	1,579	(251)
Power and Storage	**455**	779	1,552
Corporate	**(70)**	(54)	(39)
Total segmented earnings	**6,585**	5,764	4,684
Interest expense	**(2,333)**	(2,265)	(2,069)
Allowance for funds used during construction	**475**	526	507
Interest income and other	**460**	(76)	184
Income before income taxes	**5,187**	3,949	3,306
Income tax (expense)/recovery	**(754)**	(432)	89
Net income	**4,433**	3,517	3,395
Net (income)/loss attributable to non-controlling interests	**(293)**	185	(238)
Net income attributable to controlling interests	**4,140**	3,702	3,157
Preferred share dividends	**(164)**	(163)	(160)
Net income attributable to common shares	**3,976**	3,539	2,997
Net income per common share			
– basic	**$4.28**	$3.92	$3.44
– diluted	**$4.27**	$3.92	$3.43

Net income attributable to common shares in 2019 was $4.0 billion or $4.28 per share (2018 – $3.5 billion or $3.92 per share; 2017 – $3.0 billion or $3.44 per share). Net income per common share increased by $0.36 per share in 2019 compared to 2018 due to the changes in net income as well as the dilutive impact of common shares issued under our Corporate ATM program in 2017 and 2018, and our DRP.

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

2019

- a valuation allowance release of $195 million related to certain prior years' U.S. tax losses resulting from our reassessment of deferred tax assets that are more likely than not to be realized
- an after-tax gain of $115 million related to the partial sale of Northern Courier
- an after-tax gain of $54 million related to the sale of the Coolidge generating station
- a deferred tax benefit of $32 million related to the impact of an Alberta corporate income tax rate reduction on our Canadian businesses not subject to rate-regulated accounting (RRA)
- an after-tax loss of $194 million related to the Ontario natural gas-fired power plant assets held for sale. The total after-tax loss on this sale is expected to be $280 million. The unrecorded portion of this loss at December 31, 2019 primarily reflects the residual costs expected to be incurred until Napanee is placed in service, including capitalized interest, as well as expected closing adjustments and will be recorded on or before closing of this transaction. Closing is anticipated by the end of first quarter 2020
- an after-tax loss of $152 million related to the sale of certain Columbia midstream assets
- an after-tax loss of $6 million related to the sale of the remainder of our U.S. Northeast power marketing contracts.

2018

- an after-tax net loss of $4 million related to our U.S. Northeast power marketing contracts
- a $143 million after-tax gain related to the sale of our interests in the Cartier Wind power facilities
- a $115 million deferred income tax recovery from an MLP regulatory liability write-off as a result of the 2018 FERC Actions
- a $52 million recovery of deferred income taxes as a result of finalizing the impact of U.S. Tax Reform
- a $27 million income tax recovery related to the sales of our U.S. Northeast power generation assets
- $25 million of after-tax income recognized on the Bison contract terminations
- a $140 million after-tax impairment charge on Bison
- a $15 million after-tax goodwill impairment charge on Tuscarora.

2017

- an $804 million recovery of deferred income taxes as a result of U.S. Tax Reform
- a $307 million after-tax net gain on the monetization of our U.S. Northeast power generation assets
- a $136 million after-tax gain on the sale of our Ontario solar assets
- a $7 million income tax recovery related to the realized loss on a third-party sale of Keystone XL project assets
- a $954 million after-tax impairment charge for the Energy East pipeline and related projects following 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.

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

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 attributable to common shares to comparable earnings is shown in the following table.

Reconciliation of net income to comparable earnings

year ended December 31 (millions of $, except per share amounts)	2019	2018	2017
Net income attributable to common shares	**3,976**	3,539	2,997
Specific items (net of tax):			
U.S. valuation allowance release	**(195)**	—	—
Gain on partial sale of Northern Courier	**(115)**	—	—
Gain on sale of Coolidge generating station	**(54)**	—	—
Alberta corporate income tax rate reduction	**(32)**	—	—
Loss on Ontario natural gas-fired power plants held for sale	**194**	—	—
Loss on sale of Columbia midstream assets	**152**	—	—
U.S. Northeast power marketing contracts	**6**	4	—
Gain on sale of Cartier Wind power facilities	**—**	(143)	—
MLP regulatory liability write-off	**—**	(115)	—
U.S. Tax Reform	**—**	(52)	(804)
Net gain on sales of U.S. Northeast power generation assets	**—**	(27)	(307)
Bison contract terminations	**—**	(25)	—
Bison asset impairment	**—**	140	—
Tuscarora goodwill impairment	**—**	15	—
Gain on sale of Ontario solar assets	**—**	—	(136)
Keystone XL income tax recoveries	**—**	—	(7)
Energy East impairment charge	**—**	—	954
Integration and acquisition related costs – Columbia	**—**	—	69
Keystone XL asset costs	**—**	—	28
Risk management activities[1]	**(81)**	144	(104)
Comparable earnings	**3,851**	3,480	2,690
Net income per common share	**$4.28**	$3.92	$3.44
Specific items (net of tax):			
U.S. valuation allowance release	**(0.21)**	—	—
Gain on partial sale of Northern Courier	**(0.12)**	—	—
Gain on sale of Coolidge generating station	**(0.06)**	—	—
Alberta corporate income tax rate reduction	**(0.03)**	—	—
Loss on Ontario natural gas-fired power plants held for sale	**0.21**	—	—
Loss on sale of Columbia midstream assets	**0.16**	—	—
U.S. Northeast power marketing contracts	**0.01**	0.01	—
Gain on sale of Cartier Wind power facilities	**—**	(0.16)	—
MLP regulatory liability write-off	**—**	(0.13)	—
U.S. Tax Reform	**—**	(0.06)	(0.92)
Net gain on sales of U.S. Northeast power generation assets	**—**	(0.03)	(0.34)
Bison contract terminations	**—**	(0.03)	—
Bison asset impairment	**—**	0.16	—
Tuscarora goodwill impairment	**—**	0.02	—
Gain on sale of Ontario solar assets	**—**	—	(0.16)
Keystone XL income tax recoveries	**—**	—	(0.01)
Energy East impairment charge	**—**	—	1.09
Integration and acquisition related costs – Columbia	**—**	—	0.08
Keystone XL asset costs	**—**	—	0.03
Risk management activities[1]	**(0.10)**	0.16	(0.12)
Comparable earnings per common share	**$4.14**	$3.86	$3.09

1 year ended December 31 (millions of $)	2019	2018	2017
Liquids marketing	**(72)**	71	—
Canadian power	**—**	3	11
U.S. power	**(52)**	(11)	39
Natural gas storage	**(11)**	(11)	12
Interest rate	**—**	—	(1)
Foreign exchange	**245**	(248)	88
Income taxes attributable to risk management activities	**(29)**	52	(45)
Total unrealized gains/(losses) from risk management activities	**81**	(144)	104

Comparable EBITDA to Comparable Earnings

Comparable EBITDA represents segmented earnings adjusted for certain aspects of the specific items described above and excludes non-cash charges for depreciation and amortization. For further information on our reconciliation to comparable EBITDA refer to the business segment financial results sections.

year ended December 31 (millions of $)	2019	2018	2017
Comparable EBITDA			
Canadian Natural Gas Pipelines	**2,274**	2,379	2,144
U.S. Natural Gas Pipelines	**3,480**	3,035	2,357
Mexico Natural Gas Pipelines	**605**	607	519
Liquids Pipelines	**2,192**	1,849	1,348
Power and Storage	**832**	752	1,030
Corporate	**(17)**	(59)	(21)
Comparable EBITDA	**9,366**	8,563	7,377
Depreciation and amortization	**(2,464)**	(2,350)	(2,048)
Interest expense included in comparable earnings	**(2,333)**	(2,265)	(2,068)
Allowance for funds used during construction	**475**	526	507
Interest income and other included in comparable earnings	**162**	177	159
Income tax expense included in comparable earnings	**(898)**	(693)	(839)
Net income attributable to non-controlling interests included in comparable earnings	**(293)**	(315)	(238)
Preferred share dividends	**(164)**	(163)	(160)
Comparable earnings	**3,851**	3,480	2,690

Comparable EBITDA – 2019 versus 2018

Comparable EBITDA in 2019 increased by $803 million compared to 2018 primarily due to the net result of the following:

- increased contribution from U.S. Natural Gas Pipelines mainly attributable to incremental earnings from Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by decreased earnings from Bison (wholly owned by TC PipeLines, LP) contract terminations and from the sale of certain Columbia midstream assets on August 1, 2019
- increased contribution from Liquids Pipelines primarily resulting from higher volumes on the Keystone Pipeline System and earnings from liquids marketing activities, partially offset by decreased earnings as a result of the sale of an 85 per cent equity interest in Northern Courier on July 17, 2019
- higher contribution from Power and Storage primarily attributable to increased Bruce Power results from a higher realized power price, partially offset by the sale of our interests in the Cartier Wind power facilities in late 2018 and the sale of the Coolidge generating facility on May 21, 2019
- lower contribution from Canadian Natural Gas Pipelines mainly due to lower flow-through income taxes on the Canadian Mainline reflecting the impact of the Canadian Mainline 2018-2020 Tolls Review (NEB 2018 Decision) and on the NGTL System as a result of accelerated tax depreciation, enacted by the Canadian federal government, partially offset by higher rate base earnings and depreciation on the NGTL System as additional facilities were placed in service
- foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent earnings from our U.S. operations.

Comparable EBITDA – 2018 versus 2017

Comparable EBITDA in 2018 increased by $1.2 billion compared to 2017 primarily due to the net result of the following:

- increased contribution from U.S. Natural Gas Pipelines mainly due to incremental earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes, and amortization of net regulatory liabilities recognized as a result of U.S. Tax Reform
- higher contribution from Liquids Pipelines primarily resulting from increased volumes on the Keystone Pipeline System, greater earnings from liquids marketing activities and intra-Alberta pipelines placed in service in the second half of 2017
- higher contribution from Canadian Natural Gas Pipelines primarily due to the recovery of increased depreciation as a result of higher rates approved in both the Canadian Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as higher overall pre-tax rate base earnings, partially offset by lower incentive earnings and flow-through income taxes
- decreased earnings from Power and Storage mainly attributable to the sales of our U.S. Northeast power generation assets in second quarter 2017 as well as lower volumes at Bruce Power resulting from greater outage days and lower results from contracting activities.

Due to the flow-through treatment of certain expenses, including income taxes and depreciation on our Canadian rate-regulated pipelines, the accelerated tax depreciation changes in 2019 and increased depreciation expense impacts our comparable EBITDA despite having no significant effect on net income.

Comparable earnings – 2019 versus 2018

Comparable earnings in 2019 were $371 million or $0.28 per common share higher than in 2018, and were primarily the net result of:

- changes in comparable EBITDA described above
- higher income tax expense due to increased comparable earnings before income taxes and lower foreign tax rate differentials, partially offset by lower flow-through income taxes on the Canadian Mainline reflecting the impact of the NEB 2018 Decision and on the NGTL System from the effect of accelerated tax depreciation
- higher depreciation largely in U.S. Natural Gas Pipelines reflecting new projects placed in service. Canadian Natural Gas Pipelines' depreciation also increased, however it is fully recovered in tolls on a flow-through basis as discussed in comparable EBITDA above, and therefore it has no significant impact on comparable earnings
- increased interest expense primarily as a result of long-term debt issuances, net of maturities, the foreign exchange impact on translation of U.S. dollar-denominated interest and higher levels of short-term borrowings, partially offset by higher capitalized interest
- lower AFUDC primarily due to Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by capital expenditures on our NGTL System and continued investment in our Mexico projects.

Comparable earnings – 2018 versus 2017

Comparable earnings in 2018 were $790 million or $0.77 per common share higher than in 2017, and were primarily the net result of:

- changes in comparable EBITDA described above
- higher depreciation primarily in Canadian Natural Gas Pipelines due to increased depreciation rates approved in the Canadian Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, which is fully recovered in tolls as described above, as well as additional depreciation related to new projects placed in service in 2017 and 2018
- increased interest expense primarily as a result of additional long-term debt issuances in 2018 and the full-year impact of long-term debt and junior subordinated notes issuances in 2017, net of maturities, as well as lower capitalized interest, partially offset by the repayment of the Columbia acquisition bridge facilities in June 2017
- lower income tax expense principally due to reduced income tax rates resulting from U.S. Tax Reform and lower flow-through income taxes in Canadian rate-regulated pipelines.

Comparable earnings per share in 2019 and 2018 were impacted by the dilutive impact of common shares issued under our Corporate ATM program in 2018 and 2017, and under our DRP. Refer to the Financial condition section of this MD&A for further information on common share issuances.

Cash flows

Net cash provided by operations of $7.1 billion and comparable funds generated from operations of $7.1 billion were eight per cent and nine per cent higher, respectively, in 2019 compared to 2018, primarily due to greater comparable earnings as described above, along with increased distributions from the operating activities of our equity investments. In addition, net cash provided by operations was affected by the amount and timing of working capital changes.

Funds used in investing activities

***Capital spending*[1]**

year ended December 31 (millions of $)	2019	2018	2017
Canadian Natural Gas Pipelines	**3,906**	2,478	2,181
U.S. Natural Gas Pipelines	**2,516**	5,771	3,830
Mexico Natural Gas Pipelines	**357**	797	1,954
Liquids Pipelines	**954**	581	529
Power and Storage	**1,019**	1,257	675
Corporate	**32**	45	41
	8,784	10,929	9,210

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

We invested $8.8 billion in capital projects in 2019 to maintain and optimize the value of our existing assets and to develop new, complementary assets in high demand areas. Our total capital spending in 2019 included contributions of $0.6 billion to our equity investments predominantly related to Bruce Power.

In 2018, we invested $10.9 billion in capital projects which included contributions of $1.0 billion to our equity investments primarily related to Sur de Texas and Bruce Power. This amount was partially offset by $470 million of Coastal GasLink pre-FID costs that were reimbursed by LNG Canada joint venture participants in 2018.

Proceeds from sales of assets

In 2019, we completed the following portfolio management transactions:

- the sale of certain Columbia midstream assets for proceeds of approximately US$1.3 billion, before post-closing adjustments
- the sale of the Coolidge generating station for proceeds of US$448 million, before post-closing adjustments
- the sale of an 85 per cent equity interest in Northern Courier for proceeds of $144 million, before post-closing adjustments.

In addition to the proceeds from the above transactions, we received a $1.0 billion distribution from the Northern Courier debt issuance which preceded the equity sale.

In 2018, we completed the sale of our interests in the Cartier Wind power facilities in Québec for net proceeds of $630 million, before post-closing adjustments.

Balance sheet

We continue to maintain a solid financial position while growing our total assets by $359 million in 2019. At December 31, 2019, common shareholders' equity, including non-controlling interests, represented 35 per cent (2018 – 34 per cent) of our capital structure, while other subordinated capital, in the form of junior subordinated notes and preferred shares, represented an additional 16 per cent (2018 – 14 per cent). Refer to the Financial condition section for more information about our capital structure.

Dividends

We increased the quarterly dividend on our outstanding common shares by eight per cent to $0.81 per common share for the quarter ending March 31, 2020 which equates to an annual dividend of $3.24 per common share. This was the 20th consecutive year we have increased the dividend on our common shares and is consistent with our goal of growing our common share dividend at an average annual rate of eight to 10 per cent through 2021 and at five to seven per cent thereafter.

Dividend reinvestment plan

Under the DRP, eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. From July 1, 2016 to October 31, 2019, common shares were issued from treasury at a discount of two per cent to market prices over a specified period.

Commencing with the dividends declared October 31, 2019, common shares purchased with reinvested cash dividends under TC Energy’s DRP will be acquired on the open market at 100 per cent of the weighted average purchase price.

Cash dividends paid

year ended December 31 (millions of $)	**2019**	**2018**	**2017**
Common shares	**1,798**	1,571	1,339
Preferred shares	**160**	158	155

OUTLOOK

Comparable earnings

Our 2020 comparable earnings per common share are expected to be consistent with 2019 considering the net impact of the following:

- growth in the average investment base for the NGTL System
- a lower effective tax rate, subject to the uncertain impact of pending U.S. Tax Reform final regulations and the recently enacted tax reforms in Mexico as discussed in the Corporate section of this MD&A
- a full-year impact from assets placed in service in 2019, new projects to be placed in service in 2020 and AFUDC recognized on the NGTL System's 2020 capital expenditures
- project development fees related to certain capital projects.

Offset by:

- asset monetizations in 2019 and 2020
- lower anticipated margins and volumes in both the Keystone Pipeline System and the liquids marketing business reflecting changing market conditions
- reduced generation output from Bruce Power due to the commencement of the Unit 6 Major Component Replacement outage
- higher financial charges as a result of lower capitalized interest and reduced AFUDC after placing new assets in service.

Consolidated capital spending and equity investments

We expect to spend approximately $8 billion in 2020 on growth projects, maintenance capital expenditures and contributions to equity investments. The majority of the 2020 capital program is attributable to spending on the NGTL System expansions, Columbia Gas modernization projects, the Bruce Power life extension program, normal course maintenance capital expenditures, and the Coastal GasLink pipeline project prior to closing of the announced equity sale. Subsequent to the closing of this equity transaction and the concurrent establishment of a secured construction credit facility, TC Energy's investment in Coastal GasLink is expected to be accounted for under the equity method and will be predominantly funded by project-level financing and equity partners.

Refer to the relevant business segment and Financial condition outlook sections for additional details on expected earnings and capital spending for 2020.

NATURAL GAS PIPELINES BUSINESS

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

- wholly-owned natural gas pipelines – 81,346 km (50,545 miles)
- partially-owned natural gas pipelines – 11,904 km (7,397 miles).

In addition to our 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.

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

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:

- primarily in-corridor expansion and extension of our existing large North American natural gas pipeline footprint
- connections to new and growing industrial and electric power generation markets and LDCs
- expanding our systems in key locations and developing new projects to provide connectivity to LNG export terminals, both operating and proposed, along the U.S. Gulf Coast; the west coast of the U.S., Mexico and Canada; and the east coast of Canada
- connections to growing Canadian and U.S. shale gas and other supplies
- additional new pipeline developments within Mexico.

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

Recent highlights

Canadian Natural Gas Pipelines

- placed approximately $1.4 billion of projects in service in 2019
- placed the $1.1 billion Aitken Creek section of the $1.6 billion North Montney project in service on January 31, 2020
- announced our NGTL System West Path Delivery and 2023 Expansion Programs totaling $1.9 billion with in-service dates between 2022 and 2023
- applied to the CER for approval of a six-year negotiated settlement from 2021 to 2026 on the Canadian Mainline (Mainline 2021-2026 Settlement)
- the NGTL System filed a System Rate Design and Services Application with the NEB and we anticipate a decision in first quarter 2020
- advanced construction activities on Coastal GasLink with an estimated project cost of $6.6 billion and received an NEB decision confirming provincial jurisdiction for the pipeline
- entered into an agreement to sell a 65 per cent equity interest in Coastal GasLink and advanced plans for a secured construction credit facility.

U.S. Natural Gas Pipelines
- placed in service approximately US$4.9 billion of projects including Mountaineer XPress and Gulf XPress
- originated an additional US$1.2 billion of growth projects
- completed the sale of certain Columbia midstream assets for proceeds of approximately US$1.3 billion
- Columbia Gulf rate case settlement approved by FERC
- achieved record throughput volumes on certain of our pipelines.

Mexico Natural Gas Pipelines
- placed Sur de Texas in service
- completed the East Section of Tula which is available for interruptible transportation services
- executed an amending commercial agreement with CFE in respect of Sur de Texas recognizing actual construction costs, levelizing tolls and extending the contract term
- ongoing negotiations with CFE on Tula and Villa de Reyes
- continued construction on the Villa de Reyes pipeline project with an expected 2020 in-service.

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, end-use markets and LNG export terminals. The network includes underground pipelines that transport natural gas predominantly under high pressure, compressor stations that act like pumps to move 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 regulated 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 29 shows our extensive pipeline network in North America that connects major supply sources and markets. The highlights shown on the map include:

Canadian Natural Gas Pipelines

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 well positioned to connect growing supply in northeast B.C. and northwest Alberta. Our large capital program for new pipeline facilities is driven by these two supply areas, along with growing demand for intra-Alberta firm transportation for electric power generation conversion from coal, oil sands development and petro-chemical feedstock as well as to our major export points at the Empress and Alberta/B.C. delivery locations. The NGTL System is also well positioned to connect WCSB supply to LNG export facilities on the Canadian west coast, through future extensions of the system or future connections to other pipelines serving that area.

Canadian Mainline: This pipeline supplies markets in Ontario, Québec, the Canadian Maritimes as well as the Midwest and Northeast U.S. from the WCSB and, through interconnects, from the Appalachian basin.

U.S. Natural Gas Pipelines

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 Gas assets are very well positioned to connect growing supply to markets in this area. This system also interconnects with other pipelines that provide access to key markets in the U.S. Northeast, the Midwest, the Atlantic coast and south to the Gulf of Mexico and its growing demand for natural gas to serve LNG exports.

ANR: This pipeline system 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 U.S. Gulf Coast region.

Columbia Gulf: This pipeline system transports growing Appalachian basin supplies to various U.S. Gulf Coast markets and LNG export terminals from its interconnections with Columbia Gas and other pipelines.

TC PipeLines, LP: We own a 25.5 per cent interest in TC PipeLines, LP, which has ownership interests in eight wholly-owned or partially-owned natural gas pipelines serving major markets in the U.S.

Mexico Natural Gas Pipelines

Sur de Texas: This offshore pipeline transports 40 per cent of Mexico's natural gas requirements from Texas to power and industrial markets in the eastern and central regions of the country. We own a 60 per cent interest in and are the operator of this pipeline.

Northwest System: The Topolobampo and Mazatlán pipelines make up our Mexico northwest system. The system runs through the states of Chihuahua and Sinaloa, supplying power plants and industrial facilities, bringing natural gas to a region of the country that previously did not have access to it.

TGNH System: This system is located in the central region of Mexico and is composed of the Tamazunchale pipeline and the Tula and Villa de Reyes pipelines currently under construction. This system supplies or will supply several power plants and industrial facilities in Veracruz, San Luis Potosí, Querétaro and Hidalgo. It has interconnects with upstream pipelines that bring in supply from the Agua Dulce and Waha basins in Texas.

Guadalajara: This pipeline supplies power plants in the state of Colima and interconnects with other systems in the state of Guadalajara. This system is currently undergoing modification to become fully bi-directional to bring continental natural gas as well as LNG to power facilities and other industrial customers.

Regulation of tolls and cost recovery

Our natural gas pipelines are generally regulated by the CER in Canada, by 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 recovery of the rate base over time through depreciation. Other costs generally recovered through tolls include OM&A, income and property taxes and interest on debt. The regulators review our costs to ensure they are reasonable and prudently incurred and approve tolls that provide 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 two of the most prolific supply regions of North America – the WCSB and the Appalachian basin. Our pipelines also source natural gas from other significant basins including the Rockies, Williston, Haynesville, Fayetteville and Anadarko basins 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 increased natural gas exports to Mexico and access to international markets via LNG exports. We expect North American natural gas demand, including LNG exports, of approximately 123 Bcf/d by 2025, reflecting an increase of approximately 19 Bcf/d from 2018 levels.

This expected increased demand for natural gas, coupled with the replacement of existing supply sources that have a natural 25 per cent annual decline rate, implies over 40 Bcf/d of new supply connections being needed in the next two years, 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
- Alberta oil sands
- exports to Mexico to fuel power generation and other industrial facilities.

Natural gas producers continue to progress opportunities to sell natural gas to global markets which involves connecting natural gas supplies to LNG export terminals, both operating and proposed, along the U.S. Gulf Coast; the west coast of Canada, the U.S. and Mexico; and the east 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 development of gas reserves 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 North American natural gas to gain market share versus coal in serving power generation markets and to compete globally through LNG exports.

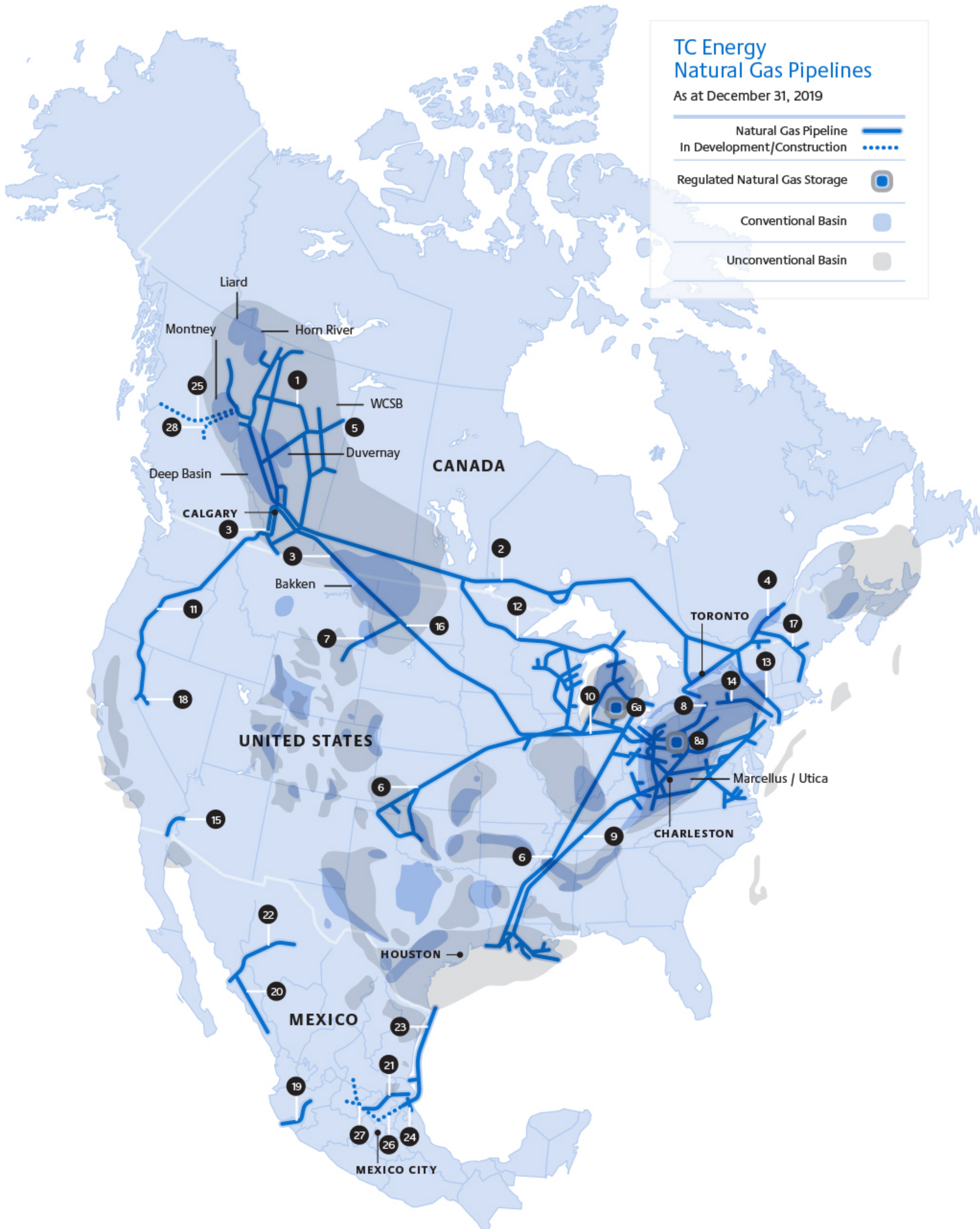
More competition

Changes in supply and demand levels and locations have resulted in increased competition for transportation services throughout North America. Our well-distributed footprint of natural gas pipelines, particularly in the liquids-rich and low-cost WCSB and the Appalachian basin, both of which are connected to North American demand centres, has placed us in a competitive position. Incumbent pipelines benefit from the connectivity and economies of scale afforded by the base infrastructure, as well as existing right-of-way and operational synergies given the increasing challenges of siting and permitting new pipeline construction and expansions. We have and will continue to offer competitive services to capture growing supply and North American demand that now includes access to global markets through LNG exports.

Strategic priorities

Our pipelines deliver the natural gas that millions of individuals and businesses across North America rely on for their energy needs. 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 2020, some of our key focus areas will be the continued execution of our existing capital program that includes further investment in the NGTL System, continued construction of Coastal GasLink, as well as the completion of pipeline projects in the U.S. and in Mexico. We will also continue to pursue the next wave of growth opportunities. Our goal is to place all of our projects in service on time and on budget while ensuring the safety of the environment and general public impacted by the construction and operation of these facilities.



TC Energy
Natural Gas Pipelines
As at December 31, 2019
Natural Gas Pipeline
In Development/Construction
Regulated Natural Gas Storage
Conventional Basin
Unconventional Basin
Liard
Montney
Horn River
WCSB
Duvernay
Deep Basin
CALGARY
CANADA
Bakken
TORONTO
UNITED STATES
Marcellus / Utica
CHARLESTON
HOUSTON
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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	24,575 km (15,270 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	14,082 km (8,750 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	1,234 km (767 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)	574 km (357 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.	50%
5	Ventures LP	133 km (83 miles)	Transports natural gas to the oil sands region near Fort McMurray, Alberta.	100%
	Great Lakes Canada[1]	60 km (37 miles)	Transports natural gas from the Great Lakes system in the U.S. to a point near Dawn, Ontario through a connection at the U.S. border underneath the St. Clair River.	100%
	U.S. pipelines and gas storage assets			
6	ANR	15,075 km (9,367 miles)	Transports natural gas from various supply basins to markets throughout the U.S. Midwest and U.S. 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 25.5 per cent of the system through our interest in TC PipeLines, LP.	25.5%
8	Columbia Gas	18,710 km (11,626 miles)	Transports natural gas primarily from the Appalachian basin to markets and pipeline interconnects throughout the U.S. Northeast, Midwest and Atlantic regions.	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%
9	Columbia Gulf	5,419 km (3,367 miles)	Transports natural gas to various markets and pipeline interconnects in the southern U.S. and U.S. 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 25.5 per cent of the system through our interest in TC PipeLines, LP.	25.5%
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. Midwest. We effectively own 65.4 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 25.5 per cent interest in TC PipeLines, LP.	65.4%

		Length	Description	Effective ownership
13	Iroquois	669 km (416 miles)	Connects with the Canadian Mainline and serves markets in New York. We effectively own 13.2 per cent of the system through a 0.7 per cent direct ownership and our 25.5 per cent interest in TC PipeLines, LP.	13.2%
14	Millennium	407 km (253 miles)	Transports natural gas primarily sourced from the Marcellus shale play to markets across southern New York and the lower Hudson Valley, as well as to New York City through its pipeline interconnections.	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 25.5 per cent of the system through our interest in TC PipeLines, LP.	25.5%
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 12.7 per cent of the system through our 25.5 per cent interest in TC PipeLines, LP.	12.7%
17	Portland	475 km (295 miles)	Connects with TQM near East Hereford, Québec to deliver natural gas to customers in the U.S. Northeast and Canadian Maritimes. We effectively own 15.7 per cent of the system through our 25.5 per cent interest in TC PipeLines, LP.	15.7%
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 25.5 per cent of the system through our interest in TC PipeLines, LP.	25.5%
	Mexico pipelines			
19	Guadalajara	313 km (194 miles)	Transports natural gas from Manzanillo, Colima to Guadalajara, Jalisco. A full bi-directional modification is currently under construction.	100%
20	Mazatlán	430 km (267 miles)	Transports natural gas from El Oro to Mazatlán, Sinaloa and connects to the Topolobampo Pipeline at El Oro, Sinaloa.	100%
21	Tamazunchale	370 km (230 miles)	Transports natural gas from Naranjos, Veracruz to Tamazunchale, San Luis Potosi and on to El Sauz, Querétaro in central Mexico.	100%
22	Topolobampo	572 km (355 miles)	Transports natural gas to El Oro, Sinaloa and Topolobampo, Sinaloa, from interconnects with third-party pipelines in El Encino, Chihuahua, and El Oro, Sinaloa.	100%
23	Sur de Texas	770 km (478 miles)	Offshore pipeline that transports natural gas from the Mexican border near Brownsville, Texas, to power plants in Altamira, Tamaulipas and Tuxpan, Veracruz, where it interconnects with the Tamazunchale and Tula pipelines and other third-party facilities.	60%
24	Tula - East Section	48 km (30 miles)	The East Section of the Tula pipeline transports natural gas from Sur de Texas to power plants in Tuxpan, Veracruz.	100%
	Under construction[2]			
	Canadian pipelines			
	North Montney[1,3]	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 System 2020 Facilities[1]	149 km (93 miles)	An expansion program on the NGTL System including multiple pipeline projects and compression additions with in-service dates expected by April, June and November 2020.	100%
25	Coastal GasLink[4]	670 km (416 miles)	A greenfield project to deliver natural gas from the Montney gas producing region to LNG Canada's liquefaction facility under construction near Kitimat, B.C.	100%

	Under construction[2] (continued)	Length	Description	Effective ownership
	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%
	Mexico pipelines			
26	Tula (excluding the Tula East Section)	276 km (171 miles)	In addition to the East Section already in service from Tuxpan, Veracruz, the pipeline will interconnect with Villa de Reyes at Tula, Hidalgo, to supply natural gas to CFE combined-cycle power generating facilities in central Mexico.	100%
27	Villa de Reyes	420 km (261 miles)	This bi-directional pipeline will transport natural gas to Tula, Hidalgo and Villa de Reyes, San Luis Potosí, connecting to the Tamazunchale and Tula pipelines, as well as other pipeline systems, and the Salamanca industrial complex in the state of Guanajuato.	100%
	Permitting and pre-construction phase[1,2]			
	Canadian pipelines			
	NGTL System 2021 Facilities	369 km (229 miles)	The 2021 NGTL Expansion Program including multiple pipeline projects and compression additions with in-service dates expected by November 2021, along with other facilities.	100%
	NGTL System 2022 Facilities	170 km (106 miles)	The 2022 NGTL Expansion Program including multiple pipeline projects and compression additions with in-service dates expected by April 2022.	100%
	NGTL System 2023 Facilities	277 km (172 miles)	The 2023 Expansion Program for the NGTL System and Foothills including multiple pipeline projects and compression additions with expected in-service dates in 2022 and 2023, along with other facilities.	100%
	U.S. pipelines			
	Louisiana XPress[5]	n/a	An expansion project of Columbia Gulf through compressor station modifications and additions with interim in-service commencing in November 2019 and full in-service expected in 2022.	100%
	Grand Chenier XPress[5]	n/a	An expansion project of ANR Pipeline through compressor station modifications and additions with expected in-service commencing in 2021 and 2022.	100%
	GTN XPress[5]	n/a	An expansion project of GTN through compressor station modifications and additions with expected in-service commencing in 2022 and 2023.	25.5%
	In development			
	Canadian pipelines			
28	Merrick Mainline[2]	260 km (161 miles)	A greenfield project to deliver natural gas from the NGTL System's existing Groundbirch Mainline near Dawson Creek, B.C. to its end point near Summit Lake, B.C.	100%
	U.S. pipelines			
	Alberta XPress[1,5]	n/a	An expansion project of ANR Pipeline through compressor station modifications and additions with expected in-service commencing in 2022.	100%
	East Lateral XPress[1,5]	n/a	An expansion project on Columbia Gulf through compressor station modifications and additions with an expected in-service date of 2022.	100%

1 Facilities and some pipelines are not shown on the map.
2 Final pipe lengths are subject to change during construction and/or final design considerations.
3 182 km (113 miles) placed in service on January 31, 2020.
4 In December 2019, we entered into an agreement to sell a 65 per cent equity interest in Coastal GasLink to KKR and AIMCo.
5 Project includes compressor station modifications and additions with no additional pipe length.

Canadian Natural Gas Pipelines

UNDERSTANDING OUR CANADIAN NATURAL GAS PIPELINES SEGMENT

The Canadian natural gas pipeline business is subject to regulation by various federal and provincial governmental agencies. The CER Act has jurisdiction over our regulated Canadian natural gas interprovincial pipeline systems, while the provinces have jurisdiction over pipeline systems operating entirely within a single province. All of our Canadian natural gas pipeline assets are regulated by the CER with the exception of Coastal GasLink, which is currently under construction, and Ventures LP.

For the interprovincial natural gas pipelines it regulates, the CER approves tolls and services that are in the public interest and provide 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 revenues 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 CER.

We and our shippers can also establish settlement arrangements, subject to approval by the CER, 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 operated under a two-year revenue-requirement settlement for 2018-2019 that included an incentive agreement with shippers providing a 50/50 sharing mechanism for any variance between fixed and actual OM&A costs. The Canadian Mainline is entering the final year of a six-year fixed toll settlement that includes an incentive arrangement. The nature of these settlements provide the pipelines 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

Canada Energy Regulator and the Impact Assessment Agency of Canada

On August 28, 2019, the CER Act came into effect, replacing the NEB Act, and the NEB was replaced by the CER. The impact assessment and decision-making for designated major transboundary pipeline projects also changed with the implementation of the new Impact Assessment Act (IA Act) on August 28, 2019, which requires designated CER projects to be assessed by an integrated review panel of the Impact Assessment Agency of Canada, formerly the Canadian Environmental Assessment Agency, and the CER. All TC Energy projects submitted to the NEB for review prior to August 28, 2019 will continue to be assessed by the CER under the previous NEB Act in accordance with the CER Act transitional rules.

Canadian Regulated Pipelines

Coastal GasLink Pipeline Project

In October 2018, we announced that we would be proceeding with construction of the Coastal GasLink natural gas pipeline project following the LNG Canada joint venture participants' announcement of a positive FID for construction of the LNG Canada natural gas liquefaction facility in Kitimat, B.C. Coastal GasLink will provide natural gas supply to the LNG Canada facility and is underpinned by 25-year TSAs (with additional renewal provisions) with each of the five LNG Canada participants. Coastal GasLink will be a 670 km (416 miles) pipeline with an initial capacity of approximately 2.2 PJ/d (2.1 Bcf/d) with potential expansion capacity up to 5.4 PJ/d (5.0 Bcf/d). All necessary regulatory permits for the initial capacity have been received, allowing us to commence construction activities in December 2018, with a planned in-service date of 2023. Coastal GasLink has signed project and community agreements with all 20 elected Indigenous bands along the pipeline route, confirming strong support from Indigenous communities across the province.

In response to a previous legal proceeding, in July 2019, the NEB issued its decision which affirmed provincial jurisdiction for Coastal GasLink. In addition, in December 2019, the B.C. Supreme Court granted the project an interlocutory injunction confirming the legal right to pursue its permitted and authorized activities through to completion.

Construction activities continue along the pipeline route. Our estimated project cost is $6.6 billion including the 2019 scope increase for refinement of construction estimates for rock work and watercourse crossings. Subject to the Coastal GasLink project governance protocols and approvals, we expect that these incremental costs will be included in the final pipeline tolls.

In December 2019, we entered into an agreement to sell a 65 per cent equity interest in Coastal GasLink to KKR-Keats Pipeline Investors II (Canada) Ltd. (KKR) and a subsidiary of Alberta Investment Management Corporation (AIMCo). Concurrent with the sale, TC Energy expects that Coastal GasLink will finalize a secured construction credit facility with a syndicate of banks to fund up to 80 per cent of the project's capital expenditures during construction. Both transactions are expected to close in the first half of 2020 subject to customary regulatory approvals and consents, including the consent of LNG Canada. As part of the transaction, we will be contracted by the Coastal GasLink Limited Partnership to construct and operate the pipeline.

Under the terms of the sale, we will receive upfront proceeds that include reimbursement of a 65 per cent proportionate share of the project costs incurred as of the closing as well as additional payment streams through construction and operation of the pipeline. We expect to record an after-tax gain of approximately $600 million upon closing of the transaction which includes the gain on sale, required revaluation of our 35 per cent residual ownership to fair market value and recognition of previously unrecorded tax benefits. Upon closing, we expect to account for our remaining 35 per cent investment using equity accounting.

The introduction of partners, establishment of a dedicated project-level financing facility, recovery of cash payments through construction for carrying charges on costs incurred and remuneration for costs to date are expected to substantially satisfy our funding requirements through project completion.

We are also committed to working with the 20 First Nations that have executed agreements with Coastal GasLink to provide them an opportunity to invest in the project. As a result, in conjunction with this sale, we will provide an option to the 20 First Nations to acquire a 10 per cent equity interest in Coastal GasLink on similar terms to what has been agreed with KKR and AIMCo.

2023 NGTL System Expansion Program

On February 12, 2020, we approved the NGTL Intra-Basin System Expansion for contracted incremental intra-basin firm delivery capacity of 331 TJ/d (309 MMcf/d) for 15-year terms. The expansion includes three segments of pipeline totaling 119 km (74 miles), 90 MW of additional compression and has an estimated capital cost of $0.9 billion with in-service dates commencing in 2023.

In October 2019, we announced our West Path Expansion Program, an expansion of our NGTL System and Foothills pipeline system for contracted incremental export capacity onto the GTN system in the Pacific Northwest. The Canadian portion of the expansion program has an estimated capital cost of $1.0 billion and consists of approximately 103 km (64 miles) of pipeline and associated facilities with in-service dates in fourth quarter 2022 and fourth quarter 2023. This total program is underpinned by approximately 275 TJ/d (258 MMcf/d) of new firm service contracts with terms that exceed 30 years.

2022 NGTL System Expansion Program

In October 2018, we announced the NGTL System 2022 Expansion Program to meet capacity requirements for incremental firm-receipt and intra-basin delivery services to commence in November 2021 and April 2022. This $1.5 billion expansion of the NGTL System consists of approximately 170 km (106 miles) of new pipeline, three compressor units, meter stations and associated facilities. Applications for approvals to construct and operate approximately $1.1 billion of the facilities, underpinned by eight-year contracts, were filed with the NEB in second quarter 2019 and are currently proceeding through public hearings expected to conclude in second quarter 2020. Pending receipt of regulatory approvals, construction would start as early as first quarter 2021.

2021 NGTL System Expansion Program

In February 2018, we announced the NGTL System 2021 Expansion Program with an estimated capital cost of $2.3 billion and an anticipated in-service date in the first half of 2021. This program consists of approximately 349 km (217 miles) of new pipeline, three compressor units and associated facilities. The expansion is required to connect incremental firm-receipt supply to commence April 2021 and expand basin export capacity by 1.1 PJ/d (1.0 Bcf/d) to the Empress export delivery point at the interconnection of the NGTL System and the Canadian Mainline. An application to construct and operate the NGTL System 2021 Expansion Program facilities was filed with the NEB in June 2018 and proceeded through a public hearing that concluded in fourth quarter 2019 with a decision pending.

NGTL System Rate Design

In March 2019, the NGTL System Rate Design and Services Application was filed with the NEB which included a contested settlement agreement negotiated with the Tolls, Tariff, Facilities and Procedures (TTFP) committee. The settlement is supported by the majority of the TTFP committee members. The application addresses rate design, terms and conditions of service for the NGTL System and a tolling methodology for the North Montney Mainline (NMML). Given the complexity of the issues raised in the application, the CER held a public hearing in fourth quarter 2019. We anticipate a decision in first quarter 2020.

Additional Expansions Placed in Service

During 2019, the NGTL System placed approximately $1.3 billion of capacity projects in service.

North Montney

On January 31, 2020, the $1.1 billion Aitken Creek section of the North Montney project was also placed in service, supplementing $0.3 billion of facilities completed in 2019. The balance of the $1.6 billion project is expected to be in service in second quarter 2020. The total project will add approximately 206 km (128 miles) of new pipeline along with three compressor units and 14 meter stations.

In May 2019, the NEB approved the proposed NMML tolling methodology including the surcharge, as filed, on an interim basis, pending the outcome of the above-noted Rate Design and Services Application.

NGTL System Revenue Requirement Settlement

The NGTL System's 2018-2019 Revenue Requirement Settlement expired on December 31, 2019. We continue to work with NGTL stakeholders towards a new revenue requirement arrangement for 2020 and subsequent years. While these discussions continue, the NGTL System is operating under interim tolls for 2020 that were approved by the CER on December 6, 2019.

Canadian Mainline

In December 2019, TC Energy filed an application on the Canadian Mainline tolls with the CER for approval of a six-year unanimous negotiated settlement with its customers and other interested parties encompassing a term from January 2021 through December 2026. The settlement sets a base equity return of 10.1 per cent on 40 per cent deemed common equity and includes an incentive to either decrease costs and/or increase revenues on the pipeline with a beneficial sharing mechanism to both the shippers and us.

In May 2019, we received NEB approval of the North Bay Junction Long-Term Fixed Price service, as filed, which adds 670 TJ/d (625 MMcf/d) of new 15-year natural gas transportation contracts from the WCSB to service markets in Ontario, Québec, New Brunswick, Nova Scotia and the northeastern U.S. using existing capacity on the Canadian Mainline as well as new compression facilities.

In March 2019, the NEB approved the Canadian Mainline tolls as filed in the January 2019 compliance filing related to the 2018-2020 Toll Review.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). Refer to page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	**2019**	**2018**	**2017**
NGTL System	**1,210**	1,197	996
Canadian Mainline	**952**	1,073	1,043
Other Canadian pipelines[1]	**112**	109	105
Comparable EBITDA	**2,274**	2,379	2,144
Depreciation and amortization	**(1,159)**	(1,129)	(908)
Comparable EBIT and segmented earnings	**1,115**	1,250	1,236

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

Canadian Natural Gas Pipelines comparable EBIT and segmented earnings decreased by $135 million in 2019 compared to 2018 and increased by $14 million in 2018 compared to 2017.

Net income and comparable EBITDA for our rate-regulated Canadian natural gas 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 revenues on a flow-through basis.

Net Income and Average Investment Base

year ended December 31 (millions of $)	**2019**	**2018**	**2017**
Net income			
NGTL System	**484**	398	352
Canadian Mainline	**173**	182	199
Average investment base			
NGTL System	**11,959**	9,669	8,385
Canadian Mainline	**3,690**	3,828	4,184

Net income for the NGTL System was $86 million higher in 2019 compared to 2018 and $46 million greater in 2018 than 2017 mainly attributable to a higher average investment base resulting from continued system expansions. The 2018-2019 Revenue Requirement Settlement and the 2017 Revenue Requirement Settlement both included an ROE of 10.1 per cent on 40 per cent deemed common equity, a mechanism for sharing variances above and below a fixed annual OM&A amount and flow-through treatment of all other costs.

The Canadian Mainline's net income in 2019 decreased by $9 million compared to 2018 mainly as a result of lower incentive earnings and a lower average investment base, partially offset by lower carrying charges to shippers on the 2019 net revenue surplus. Net income in 2018 was $17 million lower than 2017 mainly due to a lower average investment base. The lower average investment base in 2019 and 2018 was largely attributable to annual depreciation in excess of capital investment and the inclusion of net revenue surplus deferrals in investment base.

The Canadian Mainline operates under tolls approved in 2014 (NEB 2014 Decision). The NEB 2014 Decision included an approved ROE of 10.1 per cent, 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 use of deferral accounts to capture the surplus or shortfall between our revenues and cost of service for each year over the six-year fixed toll term from 2015 to 2020.

A review of tolls for the 2018-2020 period directed by the NEB 2014 Decision was received in December 2018. The NEB 2018 Decision included an accelerated amortization of the December 31, 2017 LTAA balance and an increase to the composite depreciation rate from 3.2 per cent to 3.9 per cent which was reflected in 2019 tolls.

Comparable EBITDA

Comparable EBITDA for Canadian Natural Gas Pipelines was $105 million lower in 2019 compared to 2018 primarily due to the net effect of:

- lower flow-through income taxes on the NGTL System and on the Canadian Mainline from the impact of the Canadian Mainline NEB 2018 Decision to accelerate amortization of the LTAA, as well as accelerated tax depreciation enacted in June 2019 by the Canadian federal government to allow businesses in Canada to deduct the cost of their investments more quickly for income tax purposes. Due to the flow-through treatment of income taxes on our Canadian rate-regulated pipelines, such reductions to income tax reduces our comparable EBITDA despite having no significant impact on net income
- increased rate base earnings and depreciation on the NGTL System due to additional facilities that were placed in service, which were partially offset by the impact of a lower rate base in the Canadian Mainline.

Comparable EBITDA for Canadian Natural Gas Pipelines in 2018 was $235 million higher than 2017 largely resulting from the recovery of increased depreciation as a result of higher rates approved in both the Canadian Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as higher overall pre-tax rate base earnings, partially offset by lower incentive earnings and flow-through income taxes.

Depreciation and amortization

Depreciation and amortization was $30 million higher in 2019 compared to 2018 mainly due to the additional NGTL System facilities placed in service in 2019. Depreciation and amortization was $221 million higher in 2018 compared to 2017 as a result of higher depreciation rates approved in the Canadian Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as the NGTL System facilities that were placed in service in 2018.

OUTLOOK

Comparable 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 approved by the CER.

Canadian Natural Gas Pipelines earnings in 2020 are expected to be higher than 2019 mainly due to continued growth in the NGTL System. We expect the NGTL System investment base to continue to increase as we extend and expand the supply facilities in the North Montney region, delivery facilities in northeastern Alberta and incremental service at our major border delivery locations in response to requests for firm service on the system.

We expect earnings in 2020 from the Canadian Mainline to be similar to 2019 with comparable incentive earnings and investment base. The decline in investment base due to annual depreciation out-pacing annual capital spending will be substantially offset by the accelerated amortization of the LTAA.

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.

Subject to the closing of the Coastal GasLink equity sale, we expect to begin recognizing revenues from providing development, financing and other services to the Coastal GasLink partnership in 2020.

Capital spending

We spent a total of $3.0 billion in 2019 in our Canadian natural gas pipelines business and expect to spend approximately $3.1 billion in 2020, primarily on the NGTL System expansion projects, the Canadian Mainline capacity projects and maintenance capital expenditures, all of which are immediately reflected in investment base and related earnings. As well, we spent $1.2 billion on advancing Coastal GasLink in 2019. The expected additional capital spending for the Coastal GasLink project is $2.3 billion in 2020, which, subject to closing of the equity sale transaction and establishment of a secured construction credit facility, will be predominantly funded by project-level financing and equity partners.

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. FERC, however, has comprehensive jurisdiction over our U.S. natural gas business. 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.

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 FERC for a new determination of rates, subject to any moratorium in effect. Similarly, FERC or our shippers may institute proceedings to lower rates if they consider the return on 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 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 they provide some certainty for shippers in terms of rates, eliminate the costs associated with a rate proceeding for all parties and can provide an incentive for pipelines to lower costs.

PHMSA Compliance Regulation

Our U.S. natural gas pipeline systems are subject to federal pipeline safety statutes and regulations enacted and administered by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA has disseminated regulations governing, among other things, maximum operating pressures, pipeline patrols and leak surveys, public awareness, operation and maintenance procedures, operator qualification, minimum depth requirements and emergency procedures. Additionally, PHMSA has put into place regulations requiring pipeline operators to develop and implement integrity management programs for certain natural gas pipelines that, in the event of a pipeline leak or rupture, could affect "high consequence areas", which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources and unusually sensitive ecological areas.

During 2016, PHMSA proposed new rules to revise the U.S. Federal Pipeline Safety Regulations and issued a Notice of Public Rulemaking for natural gas transmission and gathering lines that would, if adopted, impose more stringent inspection, reporting, and integrity management requirements on operators. However, PHMSA has since decided to split its 2016 proposed rule, which has become known as the "gas mega rule", into three separate rulemakings, focusing on (1) maximum allowable operating pressure, integrity assessments and non-high consequence areas known as moderate consequence areas; (2) repair criteria, safety features for pigging, inspections and corrosion control; and (3) gathering lines. The first of these three rulemakings, relating to onshore natural gas transmission pipelines, was published as a final rule on October 1, 2019. We are currently assessing the operational and financial impact related to this final rule over its 15-year implementation window beginning July 1, 2020. For additional information on the final rule published in 2019, refer to the Significant events section in the U.S. Natural Gas Pipelines segment. The remaining rulemakings comprising the gas mega rule are expected to be issued in 2020.

In addition to the rulemakings noted above, we expect new pipeline safety legislation to be proposed and finalized in 2020 that will reauthorize PHMSA pipeline safety programs, which expired under the 2016 Pipeline Safety Act, at the end of September 2019. We will continue to monitor developments and assess any potential impacts.

TC PipeLines, LP

We own a 25.5 per cent interest in, and are the general partner of, TC PipeLines, LP, a master limited partnership (MLP) which trades on the NYSE under the symbol TCP. TC PipeLines, LP has ownership interests in the GTN, Northern Border, Bison, Great Lakes, North Baja, Tuscarora, Iroquois, and Portland 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 30.

2018 FERC Actions

In 2018, FERC prescribed changes (2018 FERC Actions) related to H.R.1, the Tax Cuts and Jobs Act (U.S. Tax Reform), and, specifically, an MLP's recovery of income taxes for rate-making purposes that impact future earnings and cash flows of FERC-regulated pipelines.

FERC issued a Revised Policy Statement to address the treatment of income taxes for rate-making purposes for MLPs. The Revised Policy Statement created a presumption that entities whose earnings are not taxed through a corporation should not be permitted to recover an income tax allowance in their regulated cost-of-service rates. Regardless, FERC noted that an MLP is not automatically precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance in its cost-of-service rates. Additionally, FERC provided guidance with regards to accumulated deferred income tax (ADIT) for MLP pipelines and other pass-through entities in that, to the extent an entity's income tax allowance should be eliminated from rates, it must also eliminate its existing ADIT balance from its rate base. In response to these changes, we recorded a deferred income tax recovery of $115 million, in 2018 as a result of the write-off of MLP regulatory liabilities.

These 2018 FERC Actions also established a process and schedule by which all FERC-regulated interstate pipelines and natural gas storage facilities had to either (i) file a new uncontested rate settlement or (ii) file a FERC Form 501-G that quantified the isolated impact of U.S. Tax Reform and provided four options to address the impact for rate-making purposes.

SIGNIFICANT EVENTS

Sale of Columbia Midstream Assets

On August 1, 2019, we finalized the sale of certain Columbia midstream assets to UGI Energy Services, LLC for proceeds of approximately US$1.3 billion, before post-closing adjustments. The sale resulted in a pre-tax gain of $21 million ($152 million after-tax loss), which included the release of $595 million of Columbia goodwill allocated to these assets that is not deductible for income tax purposes. This sale did not include any interest in Columbia Energy Ventures Company, which is our minerals business in the Appalachian basin.

Columbia Gulf Rate Settlement

In December 2019, FERC approved the uncontested Columbia Gulf rate settlement which set new recourse rates for Columbia Gulf effective August 1, 2020 and instituted a rate moratorium through August 1, 2022. The revised rates are not expected to have a significant impact on our U.S. Natural Gas Pipelines segment comparable earnings.

PHMSA Compliance Regulation

In October 2019, PHMSA released its first of three final rules revising the U.S. Federal Pipeline Safety Regulations. The rule updates reporting and records retention standards for gas transmission pipelines and expands the level of required integrity assessments that must be completed on certain pipeline segments in moderate consequence areas. For example, this rule requires operators to review maximum allowable operating pressure records from previously exempted pipeline segments and perform specific remediation activities where records are not available. We are currently assessing the operational and financial impact related to this ruling which will become effective on July 1, 2020 with a 15-year implementation deadline.

Alberta XPress

On February 12, 2020, we approved the Alberta XPress project, an expansion project on the ANR Pipeline system that utilizes existing capacity on the Great Lakes and Canadian Mainline systems to connect growing supply from the WCSB to U.S. Gulf Coast LNG export markets. The anticipated in-service date is in 2022 with estimated project costs of US$0.3 billion.

Buckeye XPress

The Buckeye XPress project 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. The FERC certificate for Buckeye XPress was received in January 2020 and we expect the project to be placed in service in late 2020.

GTN XPress

In October 2019, TC PipeLines, LP approved the GTN XPress project which is an integrated reliability and expansion project on the GTN system that will provide for the transport of additional volumes enabled by the NGTL System's West Path Delivery Program discussed previously. GTN XPress is expected to be complete in late 2023 with an estimated total cost of US$0.3 billion.

East Lateral XPress

In May 2019, we approved the East Lateral XPress project, an expansion project on the Columbia Gulf system that will connect supply to U.S. Gulf Coast LNG export markets. Subject to a positive customer FID, the anticipated in-service date is in 2022 with estimated project costs of US$0.3 billion.

Louisiana XPress and Grand Chenier XPress

Combined, the Louisiana XPress and Grand Chenier XPress projects will connect nearly 2 Bcf/d of supply to U.S. Gulf Coast LNG export facilities. Both projects have obtained necessary customer approvals or waivers of conditions allowing the projects to move to the execution phase. Interim service for Louisiana XPress shippers commenced on Columbia Gulf in November 2019 with full in-service anticipated in 2022 and total estimated project costs of US$0.4 billion. The anticipated in-service dates for Grand Chenier XPress are in 2021 and 2022 for Phase I and II, respectively, with total estimated project costs of US$0.2 billion.

Mountaineer XPress and Gulf XPress

The Mountaineer XPress project, a Columbia Gas project transporting supply from the Marcellus and Utica shale plays to points along the system and the Leach interconnect with Columbia Gulf, was phased into service over first quarter 2019 along with Gulf XPress, a Columbia Gulf project.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). Refer to page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of US$, unless otherwise noted)	2019	2018	2017
Columbia Gas	**1,222**	873	623
ANR	**492**	508	400
TC PipeLines, LP[1,2]	**119**	138	118
Midstream[3]	**93**	122	93
Columbia Gulf	**164**	120	76
Great Lakes[4]	**86**	97	64
Other U.S. pipelines[1,2,5]	**79**	68	80
Non-controlling interests[6]	**368**	415	359
Comparable EBITDA	**2,623**	2,341	1,813
Depreciation and amortization	**(568)**	(511)	(453)
Comparable EBIT	**2,055**	1,830	1,360
Foreign exchange impact	**671**	541	410
Comparable EBIT (Cdn$)	**2,726**	2,371	1,770
Specific items:			
Gain on sale of Columbia midstream assets	**21**	—	—
Bison asset impairment[7]	**—**	(722)	—
Tuscarora goodwill impairment[7]	**—**	(79)	—
Bison contract terminations[7]	**—**	130	—
Integration and acquisition related costs – Columbia	**—**	—	(10)
Segmented earnings (Cdn$)	**2,747**	1,700	1,760

1 Results reflect our earnings from TC PipeLines, LP's ownership interests in eight natural gas pipelines as well as general and administrative costs related to TC PipeLines, LP. Results from Northern Border and Iroquois reflect our share of equity income from these investments. In June 2017, TC PipeLines, LP acquired 49.34 per cent of our 50 per cent interest in Iroquois and our remaining 11.81 per cent direct interest in Portland.

2 TC PipeLines, LP periodically conducted ATM issuances which decreased our ownership in TC PipeLines, LP. Effective March 2018, this program ceased to be utilized. Our ownership interest in TC PipeLines, LP was 25.5 per cent as at December 31, 2019 and December 31, 2018 compared to 25.7 per cent at December 31, 2017.

3 Includes certain Columbia midstream assets until sold on August 1, 2019.

4 Reflects our 53.55 per cent direct interest in Great Lakes. The remaining 46.45 per cent is held by TC PipeLines, LP.

5 Reflects earnings from our ownership interests in Iroquois and Portland until June 2017, Crossroads, Millennium and Hardy Storage, as well as general and administrative and business development costs related to U.S. natural gas pipelines.

6 Reflects earnings attributable to portions of TC PipeLines, LP, Portland (until June 2017) and Columbia Pipeline Partners LP (until February 2017) that we do not own.

7 These amounts were recorded in TC PipeLines, LP. The pre-tax impact to us is 25.5 per cent of these amounts net of non-controlling interests.

U.S. Natural Gas Pipelines segmented earnings in 2019 increased by $1,047 million compared to 2018 and decreased by $60 million in 2018 compared to 2017 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a pre-tax gain of $21 million related to the sale of certain Columbia midstream assets in August 2019
- a $722 million pre-tax non-cash asset impairment charge in 2018 related to Bison
- a $79 million pre-tax non-cash goodwill impairment charge in 2018 related to Tuscarora
- $130 million of pre-tax customer termination payments that were recorded in Revenues with respect to two of Bison's transportation contracts
- pre-tax costs of $10 million in 2017 mainly related to retention and severance expenses resulting from the Columbia acquisition.

Each of the specific items in 2018 noted above are before reduction for the 74.5 per cent non-controlling interests in TC Pipelines, LP.

Earnings from our U.S. Natural Gas Pipelines operations 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$282 million higher in 2019 than 2018 primarily due to the net effect of:

- incremental earnings from Columbia Gas and Columbia Gulf growth projects placed in service
- decreased earnings from Bison (wholly owned by TC PipeLines, LP) following 2018 customer agreements to pay out their future contracted revenues and terminate their contracts
- decreased earnings as a result of the sale of certain Columbia midstream assets on August 1, 2019.

Comparable EBITDA for U.S. Natural Gas Pipelines was US$528 million higher in 2018 than 2017 primarily due to the net effect of:

- incremental earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes, and improved commodity prices and throughput volumes in midstream
- increased earnings from the amortization of the net regulatory liabilities that were recorded at the end of 2017, pursuant to the 2018 FERC Actions, partially offset by a reduction in certain rates on Columbia Gas as a result of U.S. Tax Reform
- a US$10 million refund from GTN to its recourse rate customers as per the 2018 GTN Settlement.

Depreciation and amortization

Depreciation and amortization was US$57 million higher in 2019 compared to 2018 mainly due to new projects placed in service, partially offset by lower depreciation as a result of the Bison asset impairment in 2018 and was US$58 million higher in 2018 compared to 2017 mainly due to new projects placed in service.

OUTLOOK

Comparable earnings

U.S. Natural Gas Pipelines earnings are generally affected by contracted volume levels, volumes delivered and the rates charged, as well as by the cost of providing services. 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.

Our ability to retain customers and 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 can be impacted by safety, environmental and other regulators' decisions.

U.S. Natural Gas Pipelines earnings in 2020 are expected to be consistent with 2019. This is due to, among other factors, increased revenues following the completion of expansion projects on the Columbia Gas and Columbia Gulf systems in 2019. These projects will provide our customers with greater access to new sources of supply while extending their market reach. Our pipeline systems continue to see historically strong demand for service and we anticipate our assets will maintain high utilization levels as were experienced in 2019. These continued positive results will be generally offset by the sale of the Columbia midstream assets on August 1, 2019.

ANR is positioned to continue to benefit from its combination of long-term contracts originating in the WCSB, Utica and Marcellus shale plays, a broad reach of storage and transmission services to customers in the Midwest, and its connectivity to Texas and the U.S. Gulf Coast area production and end-use markets including LNG exporters. We expect ANR to provide stable earnings for 2020 consistent with 2019.

We continue to progress expansion projects in development across our existing geographical footprint that are expected to allow for the transport of additional natural gas production to areas of demand. 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 developments in supply fundamentals. Columbia Gulf's access to the U.S. Gulf Coast area provides a source of low-cost gas production that can supply growing industrial demand and LNG export markets.

Capital spending

We spent a total of US$1.9 billion in 2019 on our U.S. natural gas pipelines and expect to spend approximately US$2.0 billion in 2020 primarily on Columbia Gas, ANR and GTN expansion projects and our Columbia Gas modernization program, as well as Columbia Gas and ANR maintenance capital, which is generally expected to be recovered 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 the use of fuel oil and diesel as its primary energy source for electric generation to using natural gas. As a result, new natural gas pipeline infrastructure has been and continues to be required to meet the growing demand for natural gas. Large natural gas pipelines in Mexico have been developed primarily through a competitive bid process. The CFE, Mexico's state-owned electric utility, is the counterparty on all of our existing long-term contracts, which are predominately denominated in U.S. dollars. These fixed-rate contracts are generally designed to recover the cost of our service and earn a return on and of invested capital. As pipeline operator, we are at risk for operating and construction cost overruns and are subject to penalties, excluding force majeure events. Our Mexico pipelines have approved tariffs, services and related rates for other potential users.

SIGNIFICANT EVENTS

CFE Arbitration

In June 2019, CFE filed requests for arbitration under the Sur de Texas, Villa de Reyes and Tula contracts. CFE requested nullification of clauses that govern the parties' responsibilities in instances of force majeure and requested reimbursement of certain related fixed capacity payments. An amending agreement was successfully executed for the Sur de Texas pipeline and CFE withdrew its Sur de Texas arbitration request. The arbitration processes for Villa de Reyes and Tula, and their fixed capacity payments under force majeure, have been suspended while negotiations with respect to the transportation services agreements progress.

Sur de Texas

The Sur de Texas pipeline began commercial operation in September 2019 following execution of the amending agreement with CFE. The original Sur de Texas agreement had a fluctuating toll profile over a 25-year contract term. As a result of the amendment, the contract has been extended 10 years and CFE will receive transportation services for 35 years under a levelized toll structure based on actual construction costs with an initial fixed toll applicable for the first 25 years of the contract term and a higher fixed toll over the last 10 years of the contract. All other terms and conditions of the contract remain substantially unchanged. Monthly revenues for this pipeline will be recognized at a levelized average rate over the 35-year contract term.

Villa de Reyes

Construction for the Villa de Reyes project is ongoing with a phased in-service anticipated to commence in second quarter 2020 with full in-service by the end of 2020. We have received capacity payments under force majeure provisions up to May 2019 but have not commenced recording revenues.

Tula

The East Section of the Tula pipeline is available for interruptible transportation services until regular service under the CFE contract commences. Construction of the central segment of the Tula project has been delayed due to a lack of progress by the Secretary of Energy, the governmental department responsible for Indigenous consultations. The west section of Tula is mechanically complete and anticipated to go into service as soon as gas becomes available. Project completion is expected approximately two years after the consultation process is successfully concluded. We have received capacity payments under force majeure provisions up to June 2019 but have not commenced recording revenues.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). Refer to page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of US$, unless otherwise noted)	**2019**	**2018**	**2017**
Topolobampo	**159**	172	157
Tamazunchale	**120**	127	112
Mazatlán	**70**	78	65
Guadalajara	**65**	71	68
Sur de Texas[1]	**43**	16	8
Other	**—**	4	(11)
Comparable EBITDA	**457**	468	399
Depreciation and amortization	**(87)**	(75)	(72)
Comparable EBIT	**370**	393	327
Foreign exchange impact	**120**	117	99
Comparable EBIT and segmented earnings (Cdn$)	**490**	510	426

1 Represents equity income from our 60 per cent interest.

Mexico Natural Gas Pipelines segmented earnings in 2019 decreased by $20 million compared to 2018 and increased by $84 million in 2018 compared to 2017.

Comparable EBITDA for Mexico Natural Gas Pipelines decreased by US$11 million in 2019 compared to 2018 mainly due to the net effect of:

- higher equity earnings from our investment in the Sur de Texas pipeline which was placed in service in September 2019, at which time we began recording equity income from operations. Prior to in-service, Sur de Texas equity income reflected AFUDC net of our proportionate share of interest expense on inter-affiliate loans. Our share of this interest expense is fully offset in Interest income and other
- lower revenues from other operations primarily as a result of changes in timing of revenue recognition in 2018.

Comparable EBITDA for Mexico Natural Gas Pipelines was US$69 million higher in 2018 than 2017 primarily from the net effect of:

- higher revenues from operations due to changes in timing of revenue recognition
- incremental earnings from a CRE tariff increase on our operating pipelines
- the $12 million impairment of our equity investment in TransGas in 2017, recorded in Other above
- equity earnings from our investment in the Sur de Texas pipeline which recorded AFUDC during construction, net of our proportionate share of interest expense on inter-affiliate loans. Our share of this interest expense is fully offset in Interest income and other.

Depreciation and amortization

Depreciation and amortization in 2019 increased by US$12 million compared with the same period in 2018 reflecting new assets being placed in service and other adjustments. Depreciation and amortization in 2018 was consistent with 2017.

OUTLOOK

Comparable earnings

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

Due to the long-term nature of the underlying transportation contracts, earnings are generally consistent year-over-year except when new assets are placed into service. Earnings for 2020 are expected to be higher than 2019 due to a full year of operations for the Sur de Texas pipeline as well as fees associated with its completion and operation, and the incremental contribution from the Villa de Reyes pipeline, expected to be fully in service by the end of 2020.

Capital spending

We incurred capital spending of US$0.3 billion in 2019 on our Sur de Texas and Villa de Reyes natural gas pipelines and expect to spend US$0.1 billion in 2020, primarily to complete the Villa de Reyes pipeline.

NATURAL GAS PIPELINES – BUSINESS RISKS

The following are risks specific to our natural gas pipelines business. Refer to page 83 for information about general risks related to TC Energy as a whole, including other operational, safety and financial risks, as well as our approach to risk management.

Production levels within supply basins

The NGTL System and our pipelines downstream depend largely on supply from the WCSB. Our Columbia System and its connecting pipes largely depend on Appalachian supply. We continue to monitor any changes in our customers' natural gas production plans and how these 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 increased competition 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 and natural gas liquids, basin-on-basin competition, pipeline and gas-processing tolls, demand within the basin, changes in regulations, and the overall value of the reserves, including liquids content.

Market access

We compete for market share with other natural gas pipelines. New supply basins being developed closer to markets we have historically served may reduce the throughput and/or distance of haul on our existing pipelines and impact revenues. New markets, including those created by LNG export facilities developed to access global natural gas demand, can lead to increased revenues 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 competitive transportation services 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, energy conservation and demand for and prices of alternative sources of energy. Renewal of expiring contracts and the opportunity to charge a competitive toll depends on the overall demand for transportation service. A decrease in the level of demand for our pipeline transportation services could adversely impact revenues. Utilization of our pipeline capacity continues to grow and warrant further investment and expansion.

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 natural gas pipeline infrastructure. As well, sustained low natural gas prices could impact our shippers' financial condition and their ability to meet their transportation service cost obligations.

Regulatory risk

Decisions and evolving policies by regulators and other government authorities, including changes in regulation, 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 construction costs, in-service dates, anticipated revenues, and the opportunity to further invest 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 delayed or lead to an unfavourable decision due to influence from the evolving role of activists and other stakeholders and their impact on public opinion and government policy related to natural gas pipeline infrastructure development. In addition, a number of these matters may also involve legal disputes that are prosecuted in a court of law, thereby further impacting project costs and creating delays.

Increased scrutiny of operating processes by the regulator, courts 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 manage these risks by monitoring regulatory developments and decisions to determine the possible impact on our natural gas pipelines business and the development of rate, facility and tariff applications that account for and mitigate the risks where possible.

Governmental risk

Shifts in government policy by existing bodies or following changes in government can impact our ability to grow our business. Restrictions on carbon fuel use, cross-border economic activity, and development of new infrastructure can impact our opportunities for continued growth. We are committed to working with all levels of government to ensure our business benefits and risks are understood, and mitigation strategies implemented.

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 revenues 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 continuously, 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 when necessary. We also calibrate meters regularly to ensure accuracy and employ robust reliability and integrity programs to maintain compression equipment and ensure safe and reliable operations.

Liquids Pipelines

Our existing liquids pipelines infrastructure connects Alberta crude oil supplies to U.S. refining markets in Illinois, Oklahoma and the U.S. Gulf Coast, as well as U.S. crude oil supplies from the key market hub at Cushing, Oklahoma to the U.S. Gulf Coast. We also provide intra-Alberta liquids transportation.

Our liquids pipelines business includes:
- wholly-owned liquids pipelines – approximately 4,400 km (2,700 miles)
- wholly-owned operational and term storage – over 6.5 million barrels
- partially-owned liquids pipelines – over 500 km (300 miles).

Strategy
- focus on accessing and delivering growing North American liquids supply to key markets by expanding our crude oil pipelines infrastructure to deliver directly from supply regions seamlessly along a contiguous path to market
- maximizing the value from our current operating assets and securing organic growth around these assets
- positioning our business development activities to identify and capture attractive organic growth and acquisition opportunities
- expand transportation service offerings to other areas of the liquids value chain including ancillary services such as short-term and long-term storage of liquids, which complement our pipeline transportation infrastructure.

Recent highlights
- received a new U.S. Presidential Permit for the Keystone XL project
- received affirmation from the Nebraska Supreme Court for the Keystone XL route through the state
- Final Supplemental Environmental Impact Statement (Final SEIS) for Keystone XL issued by the U.S. Department of State
- received approval from the U.S. Bureau of Land Management allowing for the construction of the Keystone XL pipeline across federally managed lands in Montana and land managed by the U.S. Army Corps of Engineers at the Missouri River
- received $1.15 billion in proceeds from the partial monetization of Northern Courier
- placed White Spruce pipeline in service
- constructing a pipeline connection between the Keystone Pipeline System and Motiva Enterprises LLC (Motiva)'s refinery in Port Arthur, Texas.


TC Energy
Liquids Pipelines
As at December 31, 2019
Liquids Pipeline
In Development/Construction
Liquids Tank Terminal
Production Basin
Western Canadian
Sedimentary Basin
Oil Sands
CANADA
CALGARY
Williston
TORONTO
Powder River
Denver-Julesburg
UNITED STATES
CHARLESTON
Anadarko
Permian
HOUSTON
Eagle Ford
MEXICO
MEXICO CITY
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11

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		Transports crude oil from Cushing, Oklahoma to the U.S. Gulf Coast 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.	15%
5	White Spruce	72 km (45 miles)	Transports crude oil from Canadian Natural Resources Limited's Horizon facility in northeast Alberta to the Grand Rapids pipeline.	100%
	In development			
6	Keystone XL	1,947 km (1,210 miles)	To transport crude oil from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System.	100%
7	Keystone Hardisty Terminal		Crude oil terminal located at Hardisty, Alberta.	100%
8	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%
9 10	Heartland and TC Terminals	200 km (125 miles)	Terminal and pipeline facilities to transport crude oil from the Edmonton/Heartland, Alberta region to Hardisty, Alberta.	100%
11	Grand Rapids Phase II	460 km (287 miles)	Expansion of Grand Rapids to transport additional crude oil from the producing area northwest of Fort McMurray, Alberta to the Edmonton/Heartland, Alberta market region.	50%

UNDERSTANDING OUR LIQUIDS PIPELINES BUSINESS

Our Liquids Pipelines segment consists of crude oil and products pipelines, complemented by a liquids marketing business. We efficiently transport crude oil from major supply sources to markets where crude oil can be refined into various petroleum products, transport diluent and diesel products within Alberta, and offer ancillary services such as short- and long-term storage of liquids at key terminal locations to optimize the value of our pipeline assets.

We provide pipeline transportation capacity to shippers predominantly 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. The terms of service and fixed monthly payments are determined by contracts negotiated with shippers which provide for the recovery of costs we incur to construct, operate and maintain the system. Uncontracted pipeline capacity is offered to the market to secure additional contracts on a monthly spot basis which provides opportunities to generate incremental earnings. Term storage of liquids at terminals 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 Keystone Pipeline System, our largest liquids pipeline asset, transports 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. It also provides significant capacity between Cushing, Oklahoma and the U.S. Gulf Coast market, primarily transporting U.S. crude oil. Three intra-Alberta liquids pipelines – Grand Rapids, Northern Courier and White Spruce – provide crude oil, diluent and diesel transportation for producers in northern Alberta.

Our liquids marketing business provides customers with a variety of crude oil marketing services including transportation, storage and crude oil management, largely through the purchase and sale of physical crude oil. This business contracts for capacity on TC Energy pipelines as well as third-party owned pipelines and tank terminals.

Business environment

Global crude oil and liquids demand continues to grow despite a shift towards fuel efficiency and cleaner energy technologies, driven by increasing demand in Asia and an 11 per cent expected global population growth from 2019 to 2030. Global crude oil and liquids demand growth is projected to increase from 102 million Bbl/d in 2019 to 114 million Bbl/d in 2030, driven generally by the transportation and industrial sectors. In addition to meeting this anticipated demand growth of approximately 12 million Bbl/d, a significant amount of crude oil production capacity is required to offset global annual conventional decline rates totaling approximately 26 million Bbl/d by 2030.

To meet this combined 38 million Bbl/d demand requirement to 2030, a strong crude oil price environment is needed to support continuing investment. Global supply of crude oil necessary to meet this demand is expected to be sourced from countries with significant crude oil reserves, mainly in North America and the Middle East. Crude oil prices have remained relatively steady as crude oil supply management efforts, primarily by OPEC, and global demand growth have combined to stabilize and provide sufficient support for ongoing infrastructure investments.

Supply outlook

Canada

Canada has the world's third largest crude oil reserves with approximately 164 billion barrels of economically and technically recoverable conventional and oil sands reserves primarily in Alberta as of 2018. Total 2019 WCSB crude oil production was approximately 4.5 million Bbl/d and is expected to increase to 5.5 million Bbl/d by 2030, subject to the resolution of current ex-Alberta pipeline capacity constraints. Oil sands production comprises the majority of western Canadian crude oil supply at approximately 3.7 million Bbl/d and is a favourable supply source given its long reserve life, steady production and rapidly improving cost and environmental performance.

U.S.

The U.S. has become the world's largest crude oil producing country, exceeding 12 million Bbl/d in 2019. The majority of continental U.S. crude oil production is from the Williston, Eagle Ford, Niobrara and Permian basins. In recent years, the Permian basin has become the most dominant producing region accounting for approximately 30 per cent of total U.S. crude oil production and is expected to grow by 5.2 million Bbl/d to 8.6 million Bbl/d by 2030.

With light oil processing capacity being fully utilized in the U.S., and light tight oil production continuing to grow, crude oil exports increased to 3.0 million Bbl/d in 2019 compared to 2.0 million Bbl/d in 2018. By 2030, the U.S. is expected to export approximately 7.0 million Bbl/d of predominantly light crude oil and import approximately 4.7 million Bbl/d of heavy crude oil.

Demand outlook

Canada's proximity to the U.S., which is the world's largest consumer of crude oil at 18 million Bbl/d, and Canada's significant heavy crude oil production are of strategic importance to the U.S. refining industry. Many refiners in the U.S. Midwest and U.S. Gulf Coast process a wide variety of crude oil, including significant amounts of heavy crude oil. This flexibility, access to an abundance of low-cost natural gas, proximity of light and heavy crude oil supply and ready access to markets, has positioned these refineries to be among the most profitable in the world.

The U.S. Midwest and U.S. Gulf Coast refining markets have a strong reliance on heavy crude oil imports, with total imports of approximately 4.5 million Bbl/d in 2019. The U.S. Midwest refiners have total refining capacity of approximately 4.0 million Bbl/d, which requires approximately 2.1 million Bbl/d of heavy crude oil. The U.S. Gulf Coast is the largest regional refining centre in the world with a total capacity of 9.8 million Bbl/d, representing more than half of the total U.S. refining capacity. The U.S. Gulf Coast imported approximately 2.0 million Bbl/d of primarily heavy crude oil in 2019, to meet demand.

Canada is currently the largest exporter of crude oil to the U.S. at approximately 3.8 million Bbl/d. Demand for heavy crude oil in the U.S. has been resilient and is expected to remain strong for the foreseeable future. While Canada, Venezuela and Mexico are the top suppliers of heavy crude oil to the U.S., the latter two countries are experiencing declining production.

Strategic priorities

Our strategic focus is to provide transportation solutions which link growing North American supply basins to key market hubs and demand regions. Our intra-Alberta liquids pipelines and Keystone Pipeline System will form a contiguous path from Alberta through the U.S. Midwest to the U.S. Gulf Coast, which strategically positions TC Energy to provide competitive transportation solutions for growing supplies of Alberta heavy crude oil and U.S. light tight oil.

Within our established risk preferences we remain committed to:
- protecting and optimizing the value of our existing assets
- expanding and leveraging our existing infrastructure
- expanding the transportation services that we offer and extending into adjacent jurisdictions
- extending into emerging growth opportunities.

We continuously work with existing and new customers to provide pipeline transportation and terminal services. The combination of the scale and location of our assets assists us in attracting new volumes and in growing our business.

Within Alberta, we continue to position ourselves to capture WCSB production growth. Declining Latin American crude oil production has increased the demand for WCSB heavy crude oil in the U.S. Gulf Coast, which has historically relied on offshore imports. Resolution of WCSB egress issues is expected to drive substantial production growth requiring additional transportation solutions. With additional commercial support, the Heartland pipeline, Heartland Terminal and Hardisty Terminal projects, all of which have received regulatory approval, would allow shippers to seamlessly connect from the Fort McMurray production region directly to market. This would provide shippers with a contiguous path between the WCSB and destination markets, including the U.S. Gulf Coast.

Progressing Keystone XL to construction remains a key focus. The project would more than double the capacity of the Keystone Pipeline System with enhanced access to over 4.3 million Bbl/d of refinery capacity in Houston and Port Arthur, Texas, providing a critical outlet for WCSB heavy crude oil. Expanding the pipeline capacity to these key markets is expected to increase both short- and long-haul volumes.

With the fast-paced growth of U.S. light tight oil production and fully satisfied demand for light oil in North America, we will examine opportunities to expand our transportation services and extend our pipeline platform to include terminals with storage and marine export capabilities. Terminal connections and storage facilities encourage flows into pipeline systems, which we expect will help to secure long-term contracts and incremental spot volumes. We will also focus on leveraging our existing assets and development of projects to reach emerging growth regions such as the Williston and Denver-Julesburg basins.

We believe our liquids pipelines business is well positioned to endure the impact of short-term commodity price fluctuations and supply/demand responses. Our existing operations and development projects are supported by long-term contracts where we provide pipeline capacity to our customers in exchange for fixed monthly payments which are not affected by commodity prices or throughput. The cyclical nature of commodity prices may influence the pace at which our shippers expand their operations. 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.

We 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 within our risk preferences.

SIGNIFICANT EVENTS

Keystone Pipeline System

In January 2019, we entered into an agreement with Motiva to construct a pipeline connection between the Keystone Pipeline System and Motiva's 630,000 Bbl/d refinery in Port Arthur, Texas. The connection is expected to be operational in fourth quarter 2020.

In early February 2019, the Keystone Pipeline System was temporarily shut down after a leak was detected near St. Charles, Missouri. The pipeline was restarted the same day while the segment between Steele City, Nebraska to Patoka, Illinois was restarted in mid-February 2019. In October 2019, the Keystone Pipeline System was temporarily shut down after a leak was detected near Edinburg, North Dakota. The pipeline system was restarted in November 2019 following the approval of the repair and restart plan by PHMSA. These shutdowns did not significantly impact our 2019 earnings.

Keystone XL

In March 2019, the U.S. President issued a new Presidential Permit for the Keystone XL project which superseded the 2017 permit. This resulted in the dismissal of certain legal claims related to the 2017 permit and an injunction barring certain pre-construction activities and construction of the project.

The lawsuits were expanded to include challenges to the 2019 Presidential Permit and are proceeding in federal district court in Montana.

In August 2019, the Nebraska Supreme Court affirmed the November 2017 decision by the Nebraska Public Service Commission approving the Keystone XL pipeline route through the state.

The U.S. Department of State issued a Final SEIS for the project in December 2019. The Final SEIS supplements the 2014 Keystone XL SEIS and underpins the Bureau of Land Management and U.S. Army Corps of Engineers permits.

On February 7, 2020, we received approval from the U.S. Bureau of Land Management allowing for the construction of the Keystone XL pipeline across federally managed lands in Montana and land managed by the U.S. Army Corps of Engineers at the Missouri River.

We continue to actively manage legal and regulatory matters as the project advances.

White Spruce

In May 2019, the White Spruce pipeline, which transports crude oil from Canadian Natural Resources Limited's Horizon facility in northeast Alberta to the Grand Rapids pipeline, was placed in service.

Northern Courier

On July 17, 2019, we completed the sale of an 85 per cent equity interest in Northern Courier to AIMCo for gross proceeds of $144 million before post-closing adjustments, resulting in a pre-tax gain of $69 million after recording our remaining 15 per cent interest at fair value. The after-tax gain of $115 million reflects the utilization of prior years' previously unrecognized tax loss benefits. Preceding the equity sale, Northern Courier issued $1.0 billion of long-term, non-recourse debt, the proceeds from which were paid to TC Energy resulting in aggregate gross proceeds to TC Energy of $1.15 billion from this asset monetization. We remain the operator of the Northern Courier pipeline and are using the equity method to account for our remaining 15 per cent interest in our Consolidated financial statements.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). Refer to page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2019	2018	2017
Keystone Pipeline System	**1,654**	1,443	1,283
Intra-Alberta pipelines	**137**	160	33
Liquids marketing and other	**401**	246	32
Comparable EBITDA	**2,192**	1,849	1,348
Depreciation and amortization	**(341)**	(341)	(309)
Comparable EBIT	**1,851**	1,508	1,039
Specific items:			
Gain on partial sale of Northern Courier	**69**	—	—
Energy East impairment charge	**—**	—	(1,256)
Keystone XL asset costs	**—**	—	(34)
Risk management activities	**(72)**	71	—
Segmented earnings/(losses)	**1,848**	1,579	(251)
Comparable EBIT denominated as follows:			
Canadian dollars	**356**	370	255
U.S. dollars	**1,127**	876	604
Foreign exchange impact	**368**	262	180
Comparable EBIT	**1,851**	1,508	1,039

Liquids Pipelines segmented earnings increased by $269 million in 2019 compared to 2018 and by $1,830 million in 2018 compared to 2017 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a pre-tax gain in 2019 of $69 million related to the sale of an 85 per cent equity interest in Northern Courier
- a $1,256 million pre-tax impairment charge in 2017 for the Energy East pipeline and related projects
- $34 million of pre-tax costs in 2017 related to Keystone XL for the maintenance and liquidation of project assets which were expensed pending further advancement of the project.

Segmented earnings/(losses) includes unrealized gains and losses from changes in the fair value of derivatives related to our liquids marketing business which have been excluded from our calculation of comparable EBIT. The remainder of the Liquids Pipelines segmented earnings, with the exception of the specific items described above, are equivalent to comparable EBIT.

Comparable EBITDA for Liquids Pipelines was $343 million higher in 2019 compared to 2018 primarily due to the net effect of:

- increased volumes on the Keystone Pipeline System
- greater contribution from liquids marketing activities due to improved margins and volumes
- incremental contribution from the White Spruce pipeline, which was placed in service in May 2019
- decreased earnings as a result of the sale of an 85 per cent equity interest in Northern Courier in July 2019
- positive foreign exchange impact on the Canadian dollar equivalent earnings from our U.S. operations.

Comparable EBITDA for Liquids Pipelines was $501 million higher in 2018 compared to 2017 from the effect of:

- increased volumes on the Keystone Pipeline System
- greater contribution from liquids marketing activities from improved margins and volumes
- incremental contributions from our Grand Rapids and Northern Courier intra-Alberta pipelines, which began operations in the second half of 2017
- lower business development costs from recommencing capitalization of the Keystone XL expenditures in 2018.

Depreciation and amortization

Depreciation and amortization was $341 million for both 2019 and 2018 reflecting the net result of new facilities being placed in service and a stronger U.S. dollar, partially offset by the sale of an 85 per cent equity interest in Northern Courier. Depreciation and amortization was $32 million higher in 2018 than in 2017 primarily resulting from new facilities being placed in service.

OUTLOOK

Comparable earnings

Our 2020 earnings are expected to be significantly lower than 2019 in both the Keystone Pipeline System and liquids marketing business as a result of lower margins and volumes due to changing market conditions as significant market opportunities that existed in 2019 are not anticipated to persist in 2020. In addition, earnings in 2020 will be reduced following the partial monetization of Northern Courier on July 17, 2019.

Capital spending

We spent a total of $1.0 billion in 2019 primarily on the advancement of the Keystone XL project and expect to spend approximately $0.3 billion in 2020 on our liquids pipelines.

BUSINESS RISKS

The following are risks specific to our liquids pipelines business. Refer to page 83 for information about general risks related to TC Energy as a whole, including other operational, safety and financial risks, as well as our approach to risk management.

Construction and operations

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

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, particularly in light of climate change concerns, may also have an adverse impact on the regulatory process. In conjunction with this, there are individuals and special interest groups that are expressing opposition to crude oil production by lobbying against the construction of liquids pipelines. Changing environmental requirements or revisions to the current regulatory process may adversely impact the timing or ability to obtain 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, by building scenario analysis into our strategic outlook and by working closely with our stakeholders in the development and operation of our 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. Long-term 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 further develop our competitive position in the North American liquids transportation market to connect growing crude oil and diluent 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 diluent 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 management, primarily through the purchase and sale of physical crude oil. Changing market conditions could adversely impact the value of the underlying 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 the Other information – Enterprise risk management section.

Power and Storage

In addition to our company name change to TC Energy, the previously described Energy segment has been renamed the Power and Storage segment. This business consists of power generation and non-regulated natural gas storage assets.

Our power business includes approximately 6,000 MW of generation capacity that we currently either own or are developing. Our power generation assets are located in Alberta, Ontario, Québec and New Brunswick, and use natural gas and nuclear fuel sources. The majority of these assets are supported by long-term contracts.

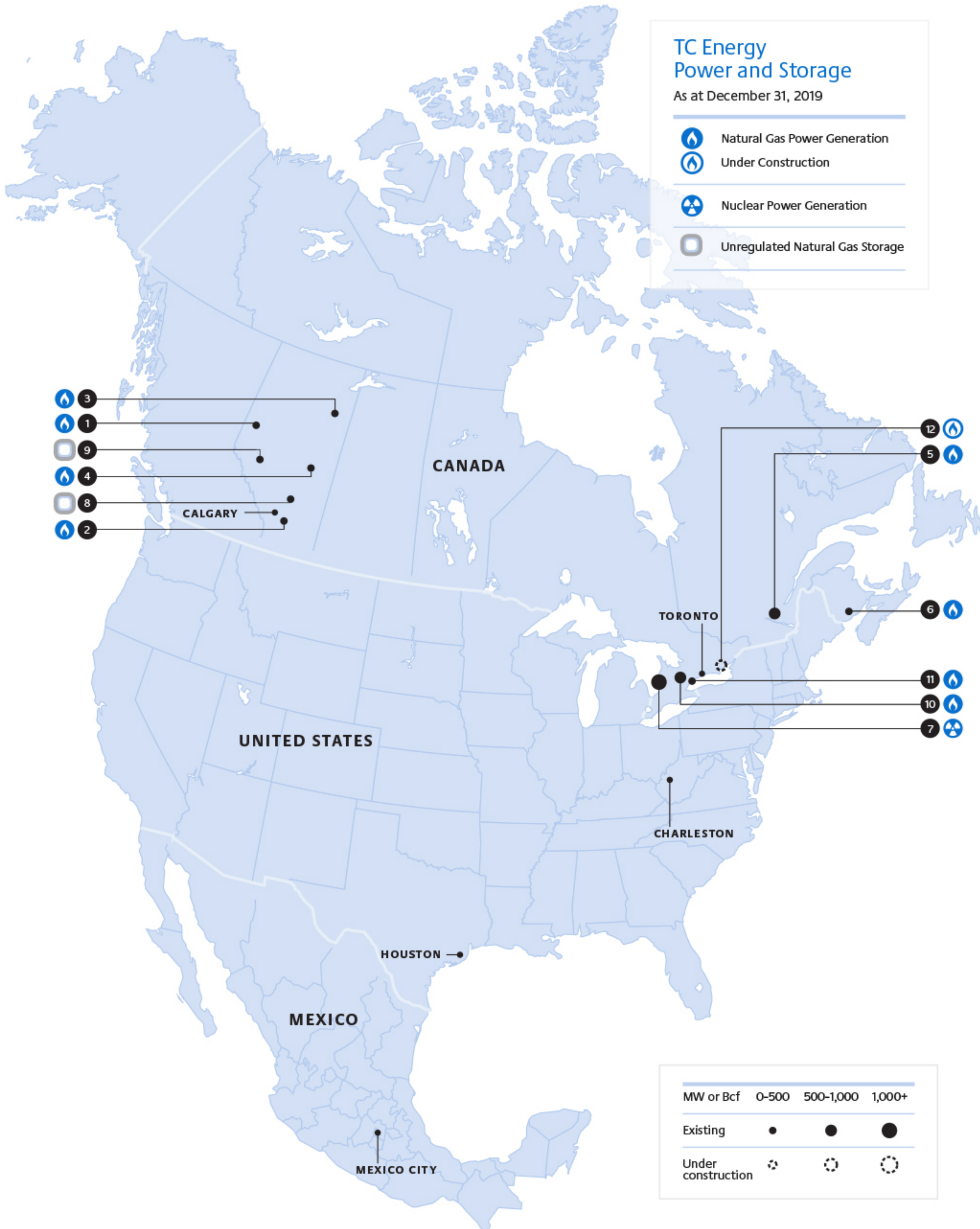
We own and operate approximately 118 Bcf of non-regulated natural gas storage capacity in Alberta.

Strategy

- maximize the value of our portfolio of Power and Storage assets by operating safely and reliably under optimized operations
- pursue North American growth in low-risk power infrastructure.

Recent highlights

- entered into an agreement to sell our Ontario natural gas-fired power plants
- completed the sales of our Coolidge generating station and our remaining U.S. Northeast power marketing contracts
- Bruce Power's contract price increased from $68 to approximately $78 per MWh including flow-through items
- advanced the life extension program at Bruce Power with the commencement of the Unit 6 Major Component Replacement (MCR) outage on January 17, 2020.


TC Energy
Power and Storage
As at December 31, 2019
Natural Gas Power Generation
Under Construction
Nuclear Power Generation
Unregulated Natural Gas Storage
CANADA
CALGARY
TORONTO
UNITED STATES
CHARLESTON
HOUSTON
MEXICO
MEXICO CITY
MW or Bcf
0-500
500-1,000
1,000+
Existing
Under construction
1
2
3
4
5
6
7
8
9
10
11
12

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

		Generating capacity (MW)	Type of fuel	Description	Ownership
	Power 6,055 MW of power generation capacity (including assets held for sale)				
	Canadian Power 2,946 MW of power generation capacity (including assets held for sale)				
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	Mackay River	207	natural gas	Cogeneration plant in Fort McMurray, Alberta.	100%
4	Redwater	46	natural gas	Cogeneration plant in Redwater, Alberta.	100%
5	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 and we continue to receive PPA capacity payments while generation is suspended.	100%
6	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%
	Bruce Power 3,109 MW of power generation capacity				
7	Bruce Power[1]	3,109	nuclear	Eight operating reactors in Tiverton, Ontario. Bruce Power leases the nuclear facilities from OPG.	48.4%
	Non-regulated natural gas storage 118 Bcf of non-regulated natural gas storage capacity				
8	Crossfield	68 Bcf		Underground facility connected to the NGTL System near Crossfield, Alberta.	100%
9	Edson	50 Bcf		Underground facility connected to the NGTL System near Edson, Alberta.	100%
	Assets held for sale				
10	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%
11	Portlands Energy[1]	275	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%
12	Napanee[2]	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 in first quarter 2020.	100%

1 Our share of power generation capacity.
2 Under construction.

UNDERSTANDING OUR POWER AND STORAGE BUSINESS

Our Power and Storage business is made up of two groups:

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

Power

Canadian Power

We own or are constructing approximately 2,950 MW of power supply in Canada, excluding our investment in Bruce Power. Although we have reached an agreement to sell our Ontario natural gas-fired power plants, results from these facilities will continue to be included in comparable EBITDA until the sale is complete.

We own four natural gas-fired cogeneration facilities in Alberta and exercise a disciplined operating strategy to maximize revenues at these facilities. Our marketing group sells uncommitted power while also buying and selling power and natural gas to maximize earnings. 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 short-term forward arrangements. The objective of this strategy is to maintain adequate power supply to fulfill our sales obligations if we have unexpected plant outages and enables us to capture opportunities to increase earnings in periods of high spot prices.

In July 2019, the Government of Alberta announced its decision to maintain the existing energy-only market instead of pursuing a capacity 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.

All the power produced by our eastern Canadian assets is sold under long-term contracts. Disciplined maintenance and optimized plant operations are essential to the results of these assets, where our earnings are based on plant availability and performance.

The IESO is continuing to proceed with reforms to the wholesale energy market in Ontario to improve efficiency with expected implementation in 2023. In July 2019, the IESO stopped work associated with installing an incremental capacity market citing changing supply needs. We continue to monitor and participate in the industry engagement processes on the Ontario market reforms to identify impacts to our existing Ontario assets and opportunities for potential growth.

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 6,430 MW. Bruce Power leases the facilities from OPG, has no spent fuel risk and will return the facilities to OPG for decommissioning at the end of the lease. We hold a 48.4 per cent ownership interest in Bruce Power.

Results from Bruce Power will fluctuate primarily due to the MCR program and the frequency, scope and duration of planned and unplanned maintenance outages. Bruce Power also markets and trades power in Ontario and neighbouring jurisdictions under strict risk controls.

Through a long-term agreement with the IESO, Bruce Power has begun to progress a series of incremental life extension investments to extend the operating life of the facility to 2064. This 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 began investing in life extension activities for Units 3 through 8 to support the long-term refurbishment programs. Investment in the Asset Management (AM) program is designed to result in near-term life extensions of each of the six units up to the planned major refurbishment outages and beyond. The AM program includes the one-time refurbishment or replacement of systems, structures or components that are not within the scope of the MCR program which focuses on the actual replacement of the key, life-limiting reactor components.

The Unit 6 MCR outage commenced on January 17, 2020 and has an expected completion in late 2023. Investments in the remaining five-unit MCR program are expected to continue through 2033. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available for Bruce Power and the IESO.

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 requests a reduction in 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.

The contract price is subject to adjustments for the return of and on capital invested at Bruce Power under the AM and MCR 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 cost efficiencies with the IESO for better than planned performance. These efficiencies are reviewed every three years and paid out on a monthly basis over the subsequent three-year period. Approximately $200 million will be paid to the IESO in 2019 to 2021 in respect to the operating and cost efficiencies realized in the 2016 to 2018 period, with our share being approximately $100 million.

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 and storage businesses.

Our natural gas storage business helps balance seasonal and short-term supply and demand while also adding 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 us and our customers the ability to capture value from short-term price movements. The natural gas storage business is affected by changes 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. In addition, the business may be affected by pipeline restrictions in Alberta which limit the ability to capture price differentials.

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

Power

Ontario natural gas-fired power plants

On July 30, 2019, we entered into an agreement to sell our Halton Hills and Napanee power plants as well as our 50 per cent interest in Portlands Energy Centre to a subsidiary of Ontario Power Generation Inc. for proceeds of approximately $2.87 billion, subject to timing of the close and related adjustments. The sale is expected to close by the end of first quarter 2020 subject to conditions which include regulatory approvals and Napanee reaching commercial operations as outlined in the agreement. We expect this sale to result in a total pre-tax loss of approximately $380 million ($280 million after tax). As these assets have been classified as held for sale, $279 million of this pre-tax loss ($194 million after tax) has been recorded at December 31, 2019. The unrecorded portion of the loss at December 31, 2019 primarily reflects the residual costs expected to be incurred until Napanee is placed in service, including capitalized interest, as well as expected closing adjustments and will be recorded on or before closing of this transaction which is anticipated by the end of first quarter 2020.

In March 2019, Napanee experienced an equipment failure while progressing commissioning activities which delayed the initial startup. This equipment failure was resolved and final commissioning activities are progressing with commercial operations expected to commence in late first quarter 2020 with an estimated project cost of $1.8 billion.

Coolidge Generating Station

In December 2018, we entered into an agreement to sell our Coolidge generating station in Arizona to SWG Coolidge Holdings, LLC (SWG). Salt River Project Agriculture Improvement and Power District (SRP), the PPA counterparty, subsequently exercised its contractual right of first refusal (ROFR) on a sale to a third party and we terminated the agreement with SWG. On May 21, 2019, we completed the sale to SRP as per the terms of their ROFR, for proceeds of US$448 million before post-closing adjustments, resulting in a pre-tax gain of $68 million ($54 million after tax).

Monetization of U.S. Northeast power marketing business

In May 2019, we sold our remaining U.S. Northeast power marketing contracts. This transaction concludes the wind-down of our U.S. Northeast power marketing business.

Bruce Power – Life Extension

Bruce Power’s Unit 6 MCR outage commenced on January 17, 2020 and is expected to be completed in late 2023. We expect to invest approximately $2.4 billion in Bruce Power's life extension programs through 2023 which includes the Unit 6 MCR, and approximately $5.8 billion post-2023. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available for Bruce Power and the IESO.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). Refer to page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of Canadian $, unless otherwise noted)	**2019**	**2018**	**2017**
Canadian Power[1,2]	**285**	428	444
Bruce Power[1]	**527**	311	434
U.S. Power[3]	**—**	—	130
Natural Gas Storage and other[4]	**20**	13	22
Comparable EBITDA	**832**	752	1,030
Depreciation and amortization	**(95)**	(119)	(151)
Comparable EBIT	**737**	633	879
Specific items:			
Loss on Ontario natural gas-fired power plants held for sale	**(279)**	—	—
Gain on sale of Coolidge generating station	**68**	—	—
U.S. Northeast power marketing contracts	**(8)**	(5)	—
Gain on sale of Cartier Wind power facilities	**—**	170	—
Net gain on sales of U.S. Northeast power generation assets	**—**	—	484
Gain on sale of Ontario solar assets	**—**	—	127
Risk management activities	**(63)**	(19)	62
Segmented earnings	**455**	779	1,552

1 Includes our share of equity income from our investments in Portlands Energy and Bruce Power.
2 Includes Coolidge generating station until sold on May 21, 2019, Cartier Wind power facilities until sold in October 2018, and Ontario Solar assets until sold in December 2017.
3 Includes U.S. Northeast power generation assets until sold in second quarter 2017.
4 Includes a $21 million impairment charge in 2017 related to obsolete equipment.

Power and Storage segmented earnings decreased $324 million in 2019 compared to 2018 and decreased $773 million in 2018 compared to 2017 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a pre-tax loss in 2019 of $279 million related to the Ontario natural gas-fired power plant assets held for sale
- a pre-tax gain of $68 million related to the sale of the Coolidge generating station in May 2019
- a pre-tax loss in 2019 of $8 million related to our remaining U.S. Northeast power marketing contracts which were sold in May 2019 (2018 – $5 million, including a gain in first quarter 2018 on the sale of our retail contracts)
- a pre-tax gain in 2018 of $170 million related to the sale of our interests in the Cartier Wind power facilities
- a pre-tax net gain in 2017 of $484 million related to the monetization of our U.S. Northeast power generation assets which included a $715 million gain on the sale of TC Hydro, an additional loss of $211 million on the sale of the thermal and wind package and $20 million of pre-tax disposition costs
- a pre-tax gain in 2017 of $127 million related to the sale of our Ontario solar assets
- unrealized losses and gains from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks.

Refer to the Significant events section for additional information regarding 2019 dispositions.

Comparable EBITDA for Power and Storage increased $80 million in 2019 compared to 2018 primarily from the net effect of:

- increased Bruce Power results mainly due to a higher realized power price in 2019 and lower income on funds invested for future retirement benefits in 2018, partially offset by lower volumes from greater outage days. Additional financial and operating information on Bruce Power is provided below
- lower Canadian Power contribution largely as a result of the sales of our interests in the Cartier Wind power facilities in October 2018 and the Coolidge generating station on May 21, 2019. We also experienced lower results from our Alberta cogeneration plants due to higher outage days and a prior period billing adjustment at one of the plants.

Comparable EBITDA for Power and Storage decreased $278 million in 2018 compared to 2017 primarily due to the net effect of:

- lower earnings from U.S. Power mainly due to the sales of the U.S. Northeast power generation assets in second quarter 2017
- reduced earnings from Bruce Power primarily due to lower volumes resulting from increased outage days and lower results from contracting activities
- decreased Natural Gas Storage and other results primarily due to pipeline constraints in the Alberta natural gas market which limited our ability to access our storage facilities and resulted in lower realized natural gas storage price spreads
- lower earnings in Canadian Power as a result of the sales of our Ontario solar assets in December 2017 and our interest in the Cartier Wind power facilities in October 2018, partially offset by higher realized margins on higher generation volumes at our Alberta cogeneration plants.

Depreciation and amortization

Depreciation and amortization decreased by $24 million in 2019 compared to 2018 primarily from the cessation of depreciation on the Coolidge generating station in December 2018, the Halton Hills power plant in July 2019 and Cartier Wind power facilities at June 2018 upon their classification as held for sale. These decreases were partially offset by increased depreciation at our Alberta cogeneration plants due to a reassessment of the useful life of certain components. Depreciation was $32 million lower in 2018 compared to 2017 largely due to the sale of our Ontario Solar assets in December 2017 as well as the cessation of depreciation on our Cartier Wind power facilities upon classification as held for sale in June 2018.

Bruce Power results

Bruce Power results reflect our proportionate share. Comparable EBITDA and comparable EBIT are non-GAAP measures. Refer to 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)	**2019**	**2018**	**2017**
Equity income included in comparable EBITDA and EBIT comprised of:			
Revenues[1]	**1,746**	1,526	1,626
Operating expenses	**(883)**	(852)	(846)
Depreciation and other	**(336)**	(363)	(346)
Comparable EBITDA and EBIT[2]	**527**	311	434
Bruce Power – other information			
Plant availability[3]	**84%**	87%	90%
Planned outage days	**393**	280	221
Unplanned outage days	**58**	92	49
Sales volumes (GWh)[2]	**22,669**	23,486	24,368
Realized power price per MWh[4]	**$76**	$67	$67

1 Net of amounts recorded to reflect operating cost efficiencies shared with the IESO.
2 Represents our 48.4 per cent (2018 – 48.3 per cent; 2017 – 48.4 per cent) ownership interest in Bruce Power. Sales volumes include deemed generation.
3 The percentage of time the plant was available to generate power, regardless of whether it was running.
4 Calculation based on actual and deemed generation. Realized power 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.

Plant availability in 2019 was 84 per cent as planned maintenance was completed on Bruce Units 2, 3, 5 and 7. Plant availability in 2018 was 87 per cent as planned maintenance was completed on Bruce Units 1, 4 and 8. Plant availability in 2017 was 90 per cent as planned maintenance was completed on Bruce Units 3, 5 and 6.

On April 1, 2019, Bruce Power's contract price increased from approximately $68 per MWh to a final adjusted contract price of approximately $78 per MWh including flow-through items, reflecting capital to be invested under the Unit 6 MCR program and the AM program as well as annual inflation adjustments.

OUTLOOK

Comparable earnings

Our 2020 comparable earnings for the Power and Storage segment are expected to be lower than 2019 primarily as a result of a lower contribution from Bruce Power as described below, the expected sale of our Ontario natural gas-fired power plants in the first quarter of 2020 as well as the completed sale of the Coolidge generating station in May 2019. Results from our natural gas storage business are expected to be lower primarily due to a reduction in realized spreads.

Bruce Power equity income in 2020 is expected to be lower largely as a result of the Unit 6 MCR outage which commenced on January 17, 2020, partially offset by fewer non-MCR planned outage days in 2020 versus 2019 and the full-year impact of the increased contract price. Planned maintenance is expected to occur on Bruce Units 4 and 5 in the first half of 2020 and Units 3 and 8 in the second half of 2020. The average plant availability percentage in 2020, excluding Unit 6, is expected to be in the mid-80 per cent range.

Capital spending

We spent a total of $0.4 billion in 2019 on our Power and Storage assets, primarily on continuing construction of Napanee, and expect to spend less than $0.1 billion in 2020.

We invested $0.5 billion in 2019 for our share of Bruce Power's life extension and maintenance capital projects and expect to invest approximately $0.6 billion in 2020.

BUSINESS RISKS

The following are risks specific to our Power and Storage business. Refer to page 83 for information about general risks related to TC Energy as a whole, including other operational, safety and financial risks. The Power and Storage marketing business complies with our risk management policies which are described in the Other information – Enterprise risk management section.

Fluctuating power and natural gas market prices

Our portfolio of assets in eastern Canada are fully contracted and are, therefore, not materially impacted by fluctuating spot power and natural gas prices. Excluding the Ontario gas-fired power plants which we have entered into an agreement to sell, the contracts on our remaining eastern Canadian assets expire in the medium to long term and, as such, it is uncertain if we will be able to re-contract on similar terms and may face future commodity exposure in those cases.

Much of the physical power generation and fuel used in our Alberta operations is currently exposed to commodity price volatility. These exposures are partially mitigated through long-term contracts and hedging activities including selling and purchasing power and natural gas in forward markets. 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. In addition, the business may be affected by pipeline restrictions in Alberta which limit the ability to capture price differentials.

Construction and plant availability

Constructing and operating our plants to ensure services are provided safely and reliably as well as optimizing and maintaining their availability are essential to the continued success of our Power and Storage business. Unexpected outages or extended planned outages at our power plants can increase maintenance costs, lower plant output and sales revenues, 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. These markets are subject to various federal and provincial regulations. As power markets evolve, 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 power and power-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 weather, including the potential impacts of climate change, 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.

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 or additional supply from regional power transmission interconnections. We also face competition from other power companies in Alberta and Ontario as well as in the development of greenfield power plants.

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented losses (the most directly comparable GAAP measure). Refer to page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2019	2018	2017
Comparable EBITDA and EBIT	**(17)**	(59)	(21)
Specific items:			
Foreign exchange (loss)/gain – inter-affiliate loan[1]	**(53)**	5	63
Integration and acquisition related costs – Columbia	**—**	—	(81)
Segmented losses	**(70)**	(54)	(39)

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

Corporate segmented losses increased by $16 million in 2019 compared to 2018 and by $15 million in 2018 compared to 2017.

Segmented losses included foreign exchange losses of $53 million in 2019 compared to gains of $5 million in 2018 and $63 million in 2017 on our proportionate share of peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners. These amounts are recorded in Income from equity investments and have been excluded from our calculation of comparable EBITDA and EBIT as they are fully offset by corresponding foreign exchange gains and losses included in Interest income and other on the inter-affiliate loan receivable for our proportionate share of the project's long-term financing requirements.

Segmented losses in 2017 included pre-tax costs of $81 million associated with the acquisition of Columbia and have been excluded from our calculation of comparable EBIT and comparable earnings.

Comparable EBITDA increased by $42 million in 2019 compared to 2018 and decreased by $38 million in 2018 compared to 2017 primarily due to decreased and increased general and administrative costs, respectively.

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, we incurred corporate restructuring costs and recorded a provision to allow for planned severance costs in future years, as well as expected future losses under lease commitments.

Cumulatively to December 31, 2019, we have incurred costs of $86 million for employee severance and $61 million for lease commitments, net of $158 million related to costs that were recoverable through regulatory and tolling structures. The restructuring liability related to employee severance was settled as of December 31, 2018 and no additional provisions were recorded in 2019. At December 31, 2019, the restructuring liability related to lease commitments was $69 million (December 31, 2018 – $81 million). The reduction in the liability was mainly due to cash payments during the year. The remaining lease commitments provision at December 31, 2019 is expected to be drawn down by 2027.

OTHER INCOME STATEMENT ITEMS

Interest expense

year ended December 31 (millions of $)	2019	2018	2017
Interest on long-term debt and junior subordinated notes			
Canadian dollar-denominated	**(598)**	(549)	(494)
U.S. dollar-denominated	**(1,326)**	(1,325)	(1,269)
Foreign exchange impact	**(434)**	(394)	(379)
	(2,358)	(2,268)	(2,142)
Other interest and amortization expense	**(161)**	(121)	(99)
Capitalized interest	**186**	124	173
Interest expense included in comparable earnings	**(2,333)**	(2,265)	(2,068)
Specific item:			
Risk management activities	**—**	—	(1)
Interest expense	**(2,333)**	(2,265)	(2,069)

Interest expense in 2019 increased by $68 million compared to 2018 primarily due to the net effect of:
- long-term debt and junior subordinated note issuances in 2019 and 2018, net of maturities. Refer to the Financial condition section for further details on long-term debt and junior subordinated notes
- foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest
- increased levels of short-term borrowings
- higher capitalized interest, largely related to Keystone XL and Napanee.

Interest expense in 2018 increased by $196 million compared to 2017 mainly due to the net effect of:
- long-term debt and junior subordinated note issuances in 2018 and 2017, net of maturities. Refer to the Financial condition section for further details on long-term debt and junior subordinated notes
- lower capitalized interest primarily due to the completion of Grand Rapids and Northern Courier in the second half of 2017, partially offset by ongoing construction at Napanee and the recommencement of capitalization of Keystone XL costs in 2018
- increased levels of short-term borrowings
- final repayment of the Columbia acquisition bridge facilities in June 2017 resulting in lower interest and debt amortization expense.

Allowance for funds used during construction

year ended December 31 (millions of $)	2019	2018	2017
Allowance for funds used during construction			
Canadian dollar-denominated	**203**	103	174
U.S. dollar-denominated	**205**	326	259
Foreign exchange impact	**67**	97	74
Allowance for funds used during construction	**475**	526	507

AFUDC decreased by $51 million in 2019 compared to 2018 primarily as a result of Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by capital expenditures on our NGTL System and continued investment in our Mexico projects.

AFUDC increased by $19 million in 2018 compared to 2017 mainly due to continued investment in Mexico projects and additional investment in and higher rates on Columbia Gas growth projects, partially offset by our decision in the second half of 2017 not to proceed with the Energy East Pipeline and lower capital expenditures in the Canadian Mainline.

Interest income and other

year ended December 31 (millions of $)	**2019**	**2018**	**2017**
Interest income and other included in comparable earnings	**162**	177	159
Specific items:			
Foreign exchange gain/(loss) – inter-affiliate loan	**53**	(5)	(63)
Risk management activities	**245**	(248)	88
Interest income and other	**460**	(76)	184

In 2019, Interest income and other increased by $536 million compared to 2018 due to the net effect of:

- unrealized gains on risk management activities in 2019 compared to unrealized losses in 2018 primarily reflecting the weakening and strengthening of the U.S. dollar at the end of 2019 and 2018, respectively. These amounts have been excluded from comparable earnings
- higher interest income combined with a foreign exchange gain in 2019 compared to a foreign exchange loss in 2018 related to a peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture. Our proportionate share of the corresponding interest expense and foreign exchange in Sur de Texas is reflected in Income from equity investments in the Mexico Natural Gas Pipelines and Corporate segments, respectively, resulting in no impact on net income. The offsetting foreign exchange gain and loss amounts are excluded from comparable earnings
- higher realized losses in 2019 compared to 2018 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

In 2018, Interest income and other decreased by $260 million compared to 2017 due to the net effect of:

- unrealized losses on risk management activities in 2018 compared to unrealized gains in 2017, primarily reflecting the strengthening of the U.S. dollar at the end of 2018. These amounts have been excluded from comparable earnings
- higher interest income combined with a lower foreign exchange loss related to a peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture. Our proportionate share of the corresponding interest expense and foreign exchange gain in Sur de Texas is reflected in Income from equity investments in the Mexico Natural Gas Pipelines and Corporate segments, respectively, resulting in no impact on net income. The offsetting foreign exchange gain and loss amounts are excluded from comparable earnings
- realized losses in 2018 compared to realized gains in 2017 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- lower recovery in 2018 related to carrying charges on Coastal GasLink project costs incurred
- income of $10 million recognized on the termination of the Prince Rupert Gas Transmission (PRGT) project in 2017.

Income tax (expense)/recovery

year ended December 31 (millions of $)	2019	2018	2017
Income tax expense included in comparable earnings	**(898)**	(693)	(839)
Specific items:			
U.S. valuation allowance release	**195**	—	—
Loss on Ontario natural gas-fired power plants held for sale	**85**	—	—
Gain on partial sale of Northern Courier	**46**	—	—
Alberta corporate income tax rate reduction	**32**	—	—
U.S. Northeast power marketing contracts	**2**	1	—
Loss on sale of Columbia midstream assets	**(173)**	—	—
Gain on sale of Coolidge generating station	**(14)**	—	—
MLP regulatory liability write-off	**—**	115	—
U.S. Tax Reform	**—**	52	804
Bison asset impairment	**—**	44	—
Sales of U.S. Northeast power generation assets	**—**	27	(177)
Tuscarora goodwill impairment	**—**	5	—
Gain on sale of Cartier Wind power facilities	**—**	(27)	—
Bison contract terminations	**—**	(8)	—
Energy East impairment charge	**—**	—	302
Integration and acquisition related costs – Columbia	**—**	—	22
Gain on sale of Ontario solar assets	**—**	—	9
Keystone XL income tax recoveries	**—**	—	7
Keystone XL asset costs	**—**	—	6
Risk management activities	**(29)**	52	(45)
Income tax (expense)/recovery	**(754)**	(432)	89

Income tax expense included in comparable earnings in 2019 increased by $205 million compared to 2018 primarily due to higher comparable earnings before income taxes and lower foreign tax rate differentials, partially offset by lower flow-through income taxes in Canadian rate-regulated pipelines.

Income tax expense included in comparable earnings in 2018 decreased by $146 million compared to 2017 largely in response to lower U.S. income tax rates as a result of U.S. Tax Reform and lower flow-through income taxes in Canadian rate-regulated pipelines, partially offset by income taxes recorded on increased pre-tax earnings.

In addition to the tax impacts of the specific items noted in the U.S. Natural Gas Pipelines, Liquids, Power and Storage and Corporate segments, Income tax (expense)/recovery in 2019 and 2018 included the following specific items which have been excluded from our calculation of income tax expense included in comparable earnings:

- in fourth quarter 2019, a valuation allowance release of $195 million related to certain prior years' U.S. tax losses resulting from our reassessment of deferred tax assets that are more likely than not to be realized
- in second quarter 2019, a $32 million income tax recovery on deferred income tax balances attributable to our Canadian businesses not subject to RRA due to an Alberta corporate income tax rate reduction enacted in June 2019
- in fourth quarter 2018, a $115 million deferred income tax recovery from an MLP regulatory liability write-off as a result of the 2018 FERC Actions, as discussed in the Understanding our U.S. Natural Gas Pipelines segment section
- in fourth quarter 2018, a $52 million recovery of deferred income taxes as a result of finalizing the impact of U.S. Tax Reform.

Tax Reform

In December 2017, U.S. Tax Reform was signed into law and the enacted U.S. federal corporate income tax rate was reduced from 35 per cent to 21 per cent effective January 1, 2018. This resulted in a remeasurement of 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 U.S. businesses not subject to RRA, the reduction in enacted income tax rates resulted in a decrease in net deferred income tax liabilities and a deferred income tax recovery in 2017. For our U.S. businesses subject to RRA, the reduction in income tax rates resulted in a reduction in net deferred income tax liabilities and the recognition of a net regulatory liability on the Consolidated balance sheet at December 31, 2017.

Given the significance of the legislation, the SEC staff issued guidance which allowed registrants to record provisional amounts at December 31, 2017 which could be adjusted as additional information became available, prepared or analyzed during a measurement period not to exceed one year.

At December 31, 2017, we considered amounts recorded related to U.S. Tax Reform to be reasonable estimates, however, certain amounts were provisional as our interpretation, assessment and presentation of the impact of the tax law change was further clarified with additional guidance from regulatory, tax and accounting authorities received in 2018. With additional guidance provided during the permitted one-year measurement period, and upon finalizing our 2017 annual tax returns for our U.S. businesses, we recognized further adjustments to our deferred income tax liability and net regulatory liability balances as well as an additional deferred income tax recovery of $52 million in 2018.

In accordance with FERC Form 501-G and uncontested rate settlement filings, the ADIT balances for all pipelines held wholly or in part by TC PipeLines, LP were eliminated from their respective rate bases. As a result, net regulatory liabilities recorded for these assets pursuant to U.S. Tax Reform were written off, resulting in a further deferred income tax recovery of $115 million in 2018.

Under U.S. Tax Reform, the U.S. Treasury and the U.S. Internal Revenue Service issued proposed regulations in late 2018 which provided administrative guidance and clarified certain aspects of new laws with respect to interest deductibility, base erosion and anti-abuse tax (BEAT), the new dividend received deduction and anti-hybrid rules. In 2019, the U.S. Treasury and the U.S. Internal Revenue Service issued final BEAT regulations which did not have a material impact on us. The remaining proposed regulations are complex and comprehensive, and considerable uncertainty continues to exist pending release of the final regulations which is expected to occur in early 2020. If the proposed regulations are enacted as currently drafted, they are not expected to have a material impact on our consolidated financial statements as at December 31, 2019.

In late 2019, Mexico passed tax reform legislation (Mexico Tax Reform) with respect to, among other things, interest deductibility and tax reporting. The changes did not have a material impact on the 2019 Consolidated financial statements and we are currently assessing the impact for 2020 and subsequent years.

Subject to the finalization of the remaining proposed regulations under U.S. Tax Reform and the impact of Mexico Tax Reform, we expect to see lower effective tax rates in 2020 compared to 2019.

Net (income)/loss attributable to non-controlling interests

year ended December 31 (millions of $)	**2019**	**2018**	**2017**
Net income attributable to non-controlling interests included in comparable earnings	**(293)**	(315)	(238)
Specific items:			
Bison impairment	**—**	538	—
Tuscarora goodwill impairment	**—**	59	—
Bison contract terminations	**—**	(97)	—
Net (income)/loss attributable to non-controlling interests	**(293)**	185	(238)

Net (income)/loss attributable to non-controlling interests increased by $478 million in 2019 compared to 2018 and decreased by $423 million in 2018 compared to 2017 primarily due to the net effect of the following items recorded in 2018:

- a $538 million pre-tax charge related to the non-controlling interests' portion of a $722 million Bison asset impairment charge in TC PipeLines, LP
- a $59 million pre-tax charge related to the non-controlling interests' portion of a $79 million Tuscarora goodwill impairment charge in TC PipeLines, LP
- $97 million in pre-tax income related to the non-controlling interests' portion of Bison contract termination payments of $130 million received from certain customers in TC PipeLines, LP.

On consolidation, we recorded the non-controlling interests' 74.5 per cent of these transactions. These items have been excluded in the calculation of comparable earnings. Refer to the Critical accounting estimates section for more information on our goodwill and asset impairment testing.

In 2019, net income attributable to non-controlling interests included in comparable earnings decreased by $22 million compared to 2018 largely due to lower earnings in TC PipeLines, LP, partially offset by the impact of a stronger U.S. dollar which increased the Canadian dollar equivalent earnings from TC PipeLines, LP.

In 2018, net income attributable to non-controlling interests included in comparable earnings increased by $77 million compared to 2017 primarily as a result of higher earnings in TC PipeLines, LP, partially offset by our acquisition of the remaining outstanding publicly held common units of Columbia Pipeline Partners LP (CPPL) in February 2017.

Preferred share dividends

year ended December 31 (millions of $)	**2019**	**2018**	**2017**
Preferred share dividends	**(164)**	(163)	(160)

Preferred share dividends of $164 million in 2019 were consistent with 2018 and 2017.

Financial condition

We strive to maintain strong financial capacity and flexibility in all parts of the economic cycle. We rely on our operating cash flows to sustain our business, pay dividends and fund a portion of our growth. In addition, we access capital markets and engage in portfolio management 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 AIF available on SEDAR (www.sedar.com).

We believe we have the financial capacity to fund our existing capital program through predictable and growing cash flows from operations, access to capital markets, portfolio management, joint venture opportunities and asset level financing, cash on hand and substantial committed credit facilities. Annually, in fourth quarter, we renew and extend our credit facilities as required.

Balance sheet analysis

Our total assets at December 31, 2019 were $99.3 billion compared to $98.9 billion at December 31, 2018 primarily reflecting our 2019 capital spending program, partially offset by depreciation, asset sales and the impact of a weaker U.S. dollar at December 31, 2019 compared to December 31, 2018 on translation of our U.S. dollar-denominated assets.

At December 31, 2019, our total liabilities were $66.9 billion compared to $67.9 billion at December 31, 2018 primarily reflecting the net effect of movements in debt, working capital and foreign exchange rates as discussed above.

Our equity at December 31, 2019 was $32.4 billion compared to $31.0 billion at December 31, 2018. The increase is principally due to net income net of common and preferred dividends paid, partially offset by other comprehensive loss.

Consolidated capital structure

The following table summarizes the components of our capital structure.

at December 31 (millions of $, unless otherwise noted)	**2019**	**Per cent of total**	**2018**	**Per cent of total**
Notes payable	**4,300**	**5**	2,762	3
Long-term debt, including current portion	**36,985**	**46**	39,971	50
Cash and cash equivalents	**(1,343)**	**(2)**	(446)	(1)
Debt	**39,942**	**49**	42,287	52
Junior subordinated notes	**8,614**	**11**	7,508	9
Preferred shares	**3,980**	**5**	3,980	5
Common shareholders' equity[1]	**28,417**	**35**	27,013	34
	80,953	**100**	80,788	100

1 Includes non-controlling interests.

At February 10, 2020, we had unused capacity of $2.0 billion, $2.0 billion, and US$4.0 billion under our equity, TCPL Canadian debt and TCPL U.S. debt shelf prospectuses, respectively, to facilitate future access to capital markets.

Provisions of various trust indentures and credit arrangements with certain of our subsidiaries can restrict those subsidiaries' and, in certain cases, our ability to declare and pay dividends or make distributions under certain circumstances. In the opinion of management, these provisions do not currently restrict 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. We were in compliance with all of our financial covenants at December 31, 2019.

Cash flows

The following tables summarize our consolidated cash flows.

year ended December 31 (millions of $)	2019	2018	2017
Net cash provided by operations	**7,082**	6,555	5,230
Net cash used in investing activities	**(6,872)**	(10,019)	(3,699)
	210	(3,464)	1,531
Net cash provided by/(used in) financing activities	**693**	2,748	(1,419)
	903	(716)	112
Effect of foreign exchange rate changes on cash and cash equivalents	**(6)**	73	(39)
Increase/(decrease) in cash and cash equivalents	**897**	(643)	73

At December 31, 2019, our current assets totaled \$7.7 billion (2018 – \$5.1 billion) and current liabilities amounted to \$12.9 billion (2018 – \$12.9 billion), leaving us with a working capital deficit of \$5.2 billion compared to a deficit of \$7.8 billion at December 31, 2018. 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 flows from operations
- approximately \$11.3 billion of unutilized, unsecured credit facilities
- our access to capital markets, including through DRP and a Corporate ATM program, if deemed appropriate
- our portfolio management activities, if required.

Cash provided by operating activities

year ended December 31 (millions of $)	2019	2018	2017
Net cash provided by operations	**7,082**	6,555	5,230
(Decrease)/increase in operating working capital	**(293)**	102	273
Funds generated from operations	**6,789**	6,657	5,503
Specific items:			
Current income tax expense on sale of Columbia midstream assets	**320**	—	—
U.S. Northeast power marketing contracts	**8**	1	—
Bison contract terminations	**—**	(122)	—
Integration and acquisition related costs – Columbia	**—**	—	84
Keystone XL asset costs	**—**	—	34
Net (gain)/loss on sales of U.S. Northeast power generation assets	**—**	(14)	20
Comparable funds generated from operations	**7,117**	6,522	5,641

Net cash provided by operations

Net cash provided by operations increased by \$527 million in 2019 compared to 2018 primarily due to the net effect of higher earnings, greater distributions from operating activities of our equity investments, the recovery of higher depreciation on the NGTL System's investment base as well as the amount and timing of working capital changes, partially offset by the current taxes paid on the sale of certain Columbia midstream assets and cash received on the Bison contract terminations in 2018.

Net cash provided by operations increased by \$1.3 billion in 2018 compared to 2017 primarily due the net effect of higher earnings, the recovery of higher depreciation as approved by the NEB in the Mainline NEB 2018 Decision and NGTL's 2018-2019 Settlement, cash received on the Bison contract terminations as well as 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 as well as the cash impact of our specific items. Refer to page 8 for more information about non-GAAP measures.

Comparable funds generated from operations increased by $595 million in 2019 compared to 2018 primarily due to higher net cash provided by operations, adjusted for the cash impact of specific items and working capital changes.

Comparable funds generated from operations increased by $881 million in 2018 compared to 2017 mainly due to higher net cash provided by operations, adjusted for the cash impact of specific items and working capital changes.

Cash used in investing activities

year ended December 31 (millions of $)	**2019**	**2018**	**2017**
Capital spending			
Capital expenditures	**(7,475)**	(9,418)	(7,383)
Capital projects in development	**(707)**	(496)	(146)
Contributions to equity investments	**(602)**	(1,015)	(1,681)
	(8,784)	(10,929)	(9,210)
Proceeds from sales of assets, net of transaction costs	**2,398**	614	4,683
Reimbursement of costs related to capital projects in development	**—**	470	634
Other distributions from equity investments	**186**	121	362
Payment for unredeemed shares of Columbia Pipeline Group, Inc.	**(373)**	—	—
Deferred amounts and other	**(299)**	(295)	(168)
Net cash used in investing activities	**(6,872)**	(10,019)	(3,699)

Net cash used in investing activities decreased from $10.0 billion in 2018 to $6.9 billion in 2019 primarily as a result of proceeds received from the sale of certain Columbia midstream assets and the Coolidge generating station along with lower capital expenditures and contributions to equity investments. This was partially offset by increased spending on capital projects under development, non-recurrence of Coastal GasLink project recoveries realized in 2018 as well as a payment to dissenting Columbia Pipeline Group, Inc. shareholders in 2019 for the appraised value of their shares plus interest pursuant to a court decision which affirmed the original Columbia Pipeline Group, Inc. share purchase price.

Net cash used in investing activities increased from $3.7 billion in 2017 to $10.0 billion in 2018 largely as a result of proceeds received on the sales of our U.S. Northeast power generation assets and solar assets in 2017, along with higher capital expenditures and spending on capital projects in development in 2018. This was partially offset by the proceeds from the sale of our interests in the Cartier Wind power facilities and lower contributions to equity investments in 2018.

Capital spending[1]

The following table summarizes capital spending by segment.

year ended December 31 (millions of $)	2019	2018	2017
Canadian Natural Gas Pipelines	**3,906**	2,478	2,181
U.S. Natural Gas Pipelines	**2,516**	5,771	3,830
Mexico Natural Gas Pipelines	**357**	797	1,954
Liquids Pipelines	**954**	581	529
Power and Storage	**1,019**	1,257	675
Corporate	**32**	45	41
	8,784	10,929	9,210

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

Capital expenditures

Our capital expenditures were incurred primarily for the expansion of the NGTL System, Columbia Gas and Columbia Gulf natural gas pipelines as well as construction of Coastal GasLink and the Napanee power generating facility. Lower capital expenditures in 2019 reflects Columbia Gas and Columbia Gulf growth projects being completed and placed in service and the approaching completion of Napanee, partially offset by increased spending on the NGTL System and Coastal GasLink.

Capital projects in development

Costs incurred during 2019 and 2018 on capital projects in development were predominantly attributable to spending on Keystone XL, a portion of which is recoverable from shippers under certain circumstances. Spending in 2017 primarily related to Energy East and west coast LNG-related pipeline projects.

Contributions to equity investments

Contributions to equity investments decreased in 2019 compared to 2018 mainly due to lower investments in Millennium and Sur de Texas, partially offset by higher investment in Bruce Power.

Contributions to equity investments decreased in 2018 compared to 2017 largely as a result of lower annual investment in Sur de Texas and Northern Border as well as the completion of Grand Rapids in 2017, partially offset by higher investments in Millennium and Bruce Power.

Contributions to equity investments include our proportionate share of Sur de Texas debt financing.

Proceeds from sales of assets

In 2019, we completed the following portfolio management transactions:

- the sale of certain Columbia midstream assets for proceeds of approximately US$1.3 billion, before post-closing adjustments
- the sale of Coolidge generating station for proceeds of US$448 million, before post-closing adjustments
- the sale of an 85 per cent equity interest in Northern Courier for proceeds of $144 million, before post-closing adjustments.

In addition to the proceeds from the above transactions, we received a $1.0 billion distribution from the Northern Courier debt issuance which preceded the equity sale.

In October 2018, we completed the sale of our interests in the Cartier Wind power facilities in Québec for proceeds of approximately $630 million, before post-closing adjustments.

In 2017, we completed the following transactions:

- sold Ravenswood, Ironwood, Kibby Wind and Ocean State Power for proceeds of approximately US$2.029 billion, before post-closing adjustments
- sold TC Hydro for proceeds of approximately US$1.07 billion, before post-closing adjustments
- sold our Ontario solar assets for proceeds of approximately $541 million, before post-closing adjustments.

Reimbursement of costs related to capital projects in development
In November 2018, we received $470 million in accordance with provisions in the agreements with the LNG Canada joint venture participants allowing them to reimburse us for their share of pre-FID costs.

In 2017, we were notified that the PRGT-related LNG project would not be proceeding and, as a result, in October 2017, we received a payment of $634 million from Progress Energy for full recovery of our PRGT project costs plus carrying charges.

Other distributions from equity investments
Other distributions from equity investments primarily reflect our proportionate share of Bruce Power and Northern Border financings undertaken to fund their respective capital programs and to make distributions to their partners. In 2019, we received distributions of $120 million (2018 – $121 million; 2017 – $362 million) from Bruce Power in connection with their issuance of senior notes in the capital markets. We also received distributions of $66 million (2018 and 2017 – nil) from Northern Border originating from a draw on its revolving credit facility to manage capitalization levels.

Cash provided by/(used in) financing activities

year ended December 31 (millions of $)	**2019**	**2018**	**2017**
Notes payable issued, net	**1,656**	817	1,038
Long-term debt issued, net of issue costs	**3,024**	6,238	3,643
Long-term debt repaid	**(3,502)**	(3,550)	(7,085)
Junior subordinated notes issued, net of issue costs	**1,436**	—	3,468
Dividends and distributions paid	**(2,174)**	(1,954)	(1,777)
Common shares issued, net of issue costs	**253**	1,148	274
Partnership units of TC PipeLines, LP issued, net of issue costs	**—**	49	225
Common units of Columbia Pipelines Partners LP acquired	**—**	—	(1,205)
Net cash provided by/(used in) financing activities	**693**	2,748	(1,419)

Net cash provided by financing activities decreased by $2.1 billion in 2019 compared to 2018 due to lower issuances of long-term debt and common shares, partially offset by junior subordinated notes issued in 2019 and increased notes payable outstanding.

Net cash provided by financing activities increased by $4.2 billion in 2018 compared to 2017 primarily due to increased issuances of long-term debt and common shares in 2018 as well as the acquisition of CPPL and repayment of the Columbia acquisition bridge facilities in 2017, partially offset by junior subordinated notes issued in 2017.

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

Long-term debt issued

The following table outlines significant long-term debt issuances in 2019:

(millions of $) **Company**	**Issue date**	**Type**	**Maturity date**	**Amount**	**Interest rate**
TRANSCANADA PIPELINES LIMITED					
	September 2019	Medium Term Notes	September 2029	700	3.00%
	September 2019	Medium Term Notes	July 2048	300	4.18%
	April 2019	Medium Term Notes	October 2049	1,000	4.34%
NORTHERN COURIER PIPELINE LIMITED PARTNERSHIP[1]					
	July 2019	Senior Secured Notes	June 2042	1,000	3.365%

1 Subsequent to the debt issuance, we completed the sale of an 85 per cent equity interest in Northern Courier. Our remaining 15 per cent interest is accounted for using the equity method. Refer to the Liquids Pipelines significant events section for additional information.

The net proceeds of the above TCPL debt issuances were used for general corporate purposes, to fund our capital program and to repay existing debt. Preceding the equity sale, Northern Courier issued $1.0 billion of long-term, non-recourse debt, the proceeds from which were paid to TC Energy.

Long-term debt repaid

The following table outlines significant long-term debt repaid in 2019:

(millions of Canadian $, unless otherwise noted) Company	Retirement date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	November 2019	Senior Unsecured Notes	US 700	2.125%
	November 2019	Senior Unsecured Notes	US 550	Floating
	March 2019	Debentures	100	10.50%
	January 2019	Senior Unsecured Notes	US 750	7.125%
	January 2019	Senior Unsecured Notes	US 400	3.125%

Junior subordinated notes issued

In September 2019, TransCanada Trust (the Trust) issued US$1.1 billion of Trust Notes – Series 2019-A (Trust Notes) to third-party investors with a fixed interest rate of 5.50 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$1.1 billion of junior subordinated notes of TCPL at an initial fixed rate of 5.75 per cent, including a 0.25 per cent administration charge. The rate will reset commencing September 2029 until September 2049 to the then three-month London Interbank Offered Rate (LIBOR) plus 4.404 per cent per annum; from September 2049 until September 2079, the interest rate will reset to the then three-month LIBOR plus 5.154 per cent per annum. The junior subordinated notes are callable at TCPL's option at any time on or after September 15, 2029 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) TC Energy 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 long-term debt and junior subordinated notes issued and long-term debt repaid in 2019, 2018 and 2017, refer to our 2019 annual Consolidated financial statements.

Dividend Reinvestment Plan

Under the DRP, eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. From July 1, 2016 to October 31, 2019, common shares were issued from treasury at a discount of two per cent to market prices over a specified period. The participation rate by common shareholders in the DRP in 2019 was approximately 34 per cent (2018 – 35 per cent; 2017 – 36 per cent), resulting in $711 million (2018 – $870 million; 2017 – $787 million) reinvested in common equity under the program.

Commencing with the dividends declared October 31, 2019, common shares purchased under TC Energy's DRP will no longer be satisfied with shares issued from treasury at a discount, but rather will be acquired on the open market at 100 per cent of the weighted average purchase price.

TC Energy's Corporate ATM Program

In June 2017, we established an ATM program that allowed us to issue common shares from treasury from time to time, at the prevailing market price, when sold through the TSX, the NYSE, or any other existing trading market for TC Energy common shares in Canada or the United States. The ATM program, which was effective for a 25-month period, was initially established with an aggregate issuance limit of up to $1.0 billion in common shares or the U.S. dollar equivalent. In June 2018, we replenished the capacity available under the ATM program to allow for the issuance of additional common shares from treasury having an aggregate gross sales price of up to $1.0 billion for a revised total of $2.0 billion or the U.S. dollar equivalent.

In 2018, 20 million common shares (2017 – 3.5 million common shares) were issued under the Corporate ATM program at an average price of $56.13 per share (2017 – $63.03 per share) for proceeds of $1.1 billion (2017 – $216 million), net of approximately $10 million (2017 – $2 million) of related commissions and fees.

In July 2019, the Corporate ATM program expired with no common shares issued in 2019.

Common units of Columbia Pipeline Partners LP

In February 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

ATM equity issuance program

Under the TC PipeLines, LP ATM program, TC PipeLines, LP was 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 TC PipeLines, LP ATM program.

In 2018, 0.7 million units were issued under the TC PipeLines, LP ATM program for net proceeds of approximately US$39 million (2017 – 3.1 million units for net proceeds of approximately US$173 million).

In August 2019, the TC PipeLines, LP ATM program expired with no units issued in 2019.

At December 31, 2019 and 2018, our ownership interest in TC PipeLines, LP was 25.5 per cent (2017 – 25.7 per cent).

Asset drop downs

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 Portland to TC PipeLines, LP. Proceeds from these transactions were US$765 million before post-closing adjustments and were comprised of US$597 million in cash and US$168 million representing a proportionate share of Iroquois and Portland debt.

Share information

as at February 10, 2020		
Common Shares	**issued and outstanding**	
	939 million	
Preferred Shares	**issued and outstanding**	**convertible to**
Series 1	14.6 million	Series 2 preferred shares
Series 2	7.4 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**
	9 million	5 million

On December 31, 2019, 173,954 Series 1 preferred shares were converted, on a one-for-one basis, into Series 2 preferred shares and 5,252,715 Series 2 preferred shares were converted, on a one-for-one basis, into Series 1 preferred shares. For more information on preferred shares refer to the notes to our Consolidated financial statements.

Dividends

year ended December 31	2019	2018	2017
Dividends declared			
per common share	**$3.00**	$2.76	$2.50
per Series 1 preferred share	**$0.8165**	$0.8165	$0.8165
per Series 2 preferred share	**$0.89872**	$0.78835	$0.62138
per Series 3 preferred share	**$0.538**	$0.538	$0.538
per Series 4 preferred share	**$0.73872**	$0.62748	$0.46138
per Series 5 preferred share	**$0.56575**	$0.56575	$0.56575
per Series 6 preferred share	**$0.79760**	$0.69341	$0.55275
per Series 7 preferred share	**$0.98181**	$1.00	$1.00
per Series 9 preferred share	**$1.032**	$1.0625	$1.0625
per Series 11 preferred share	**$0.95**	$0.95	$0.95
per Series 13 preferred share	**$1.375**	$1.375	$1.375
per Series 15 preferred share	**$1.225**	$1.225	$1.225

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 10, 2020, we had a total of $12.8 billion of committed revolving and demand credit facilities, including:

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 2024
US$4.5 billion	US$4.5 billion	TCPL/TCPL USA/ Columbia/TAIL	Supports TCPL's and TCPL USA's U.S. dollar commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2020
US$1.0 billion	US$1.0 billion	TCPL/TCPL USA/ Columbia/TAIL	For general corporate purposes of the borrowers, guaranteed by TCPL	December 2022
Demand senior unsecured revolving credit facilities:				
$2.1 billion	$1.0 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 2.2 billion	Mexico subsidiary	For Mexico general corporate purposes, guaranteed by TCPL	Demand

At February 10, 2020, our operated affiliates had an additional $0.8 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, 2019 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Notes payable	4,300	4,300	—	—	—
Long-term debt and junior subordinated notes[1]	45,906	2,705	3,898	2,186	37,117
Operating leases[2]	721	87	154	135	345
Purchase obligations	8,029	4,420	2,033	431	1,145
	58,956	11,512	6,085	2,752	38,607

1 Excludes issuance costs.

2 Includes future payments for corporate offices, various premises, services, equipment, land and lease commitments from corporate restructuring. Some of our operating leases include the option to renew the agreement for one to 25 years.

Notes payable

Total notes payable outstanding were $4.3 billion at the end of 2019 compared to $2.8 billion at the end of 2018.

Long-term debt and junior subordinated notes

At the end of 2019, we had $37.0 billion of long-term debt and $8.6 billion of junior subordinated notes outstanding compared to $40.0 billion of long-term debt and $7.5 billion of junior subordinated notes at December 31, 2018.

We attempt to ladder the maturity profile of our debt. The weighted-average maturity of our long-term debt, excluding call features, and junior subordinated notes is approximately 23 years, with the majority of final repayments occurring beyond five years.

Interest payments

At December 31, 2019, scheduled interest payments related to our long-term debt and junior subordinated notes were as follows:

at December 31, 2019 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Long-term debt	28,645	1,968	3,645	3,326	19,706
Junior subordinated notes	30,538	492	982	982	28,082
	59,183	2,460	4,627	4,308	47,788

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)

at December 31, 2019 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Canadian Natural Gas Pipelines					
Transportation by others[1]	1,409	127	251	229	802
Capital spending – excluding Coastal GasLink[2]	1,120	1,105	15	—	—
Capital spending – Coastal GasLink[3]	3,393	2,213	1,179	1	—
U.S. Natural Gas Pipelines					
Transportation by others[1]	642	120	198	103	221
Capital spending[2]	70	41	29	—	—
Mexico Natural Gas Pipelines					
Capital spending[2]	170	170	—	—	—
Liquids Pipelines					
Capital spending[2]	245	245	—	—	—
Other	16	4	6	6	—
Power and Storage					
Capital spending[2]	651	329	272	49	1
Other[4]	228	22	44	41	121
Corporate					
Other	85	44	39	2	—
	8,029	4,420	2,033	431	1,145

1 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.

2 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.

3 Represents 100 per cent of current purchase obligations prior to the impact of the Coastal GasLink transaction announced in December 2019.

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

Our capital program is comprised of $30 billion of secured projects and $21 billion of projects under development, which are subject to key commercial or regulatory approvals. The program is expected to be financed through our growing internally generated cash flows and a combination of other funding options including:

- senior debt
- hybrid securities
- preferred shares
- asset sales
- project financing
- potential involvement of strategic or financial partners.

In addition, we may access additional funding options below, as deemed appropriate:

- common shares issued from treasury under our DRP
- common shares issued under a Corporate ATM program
- discrete common equity issuance.

GUARANTEES

Northern Courier

As part of our role as operator of the Northern Courier pipeline, we have guaranteed the financial performance of the pipeline related to delivery and terminalling of bitumen and diluent and contingent financial obligations under sub-lease agreements.

At December 31, 2019, our potential exposure under the Northern Courier guarantees was estimated to be $300 million with a carrying amount of approximately $27 million.

Sur de Texas

We and our partner on the Sur de Texas pipeline, IEnova, have jointly guaranteed the financial performance of the entity which owns the pipeline. Such agreements include a guarantee and a letter of credit which are primarily related to construction services and the delivery of natural gas. The guarantees have terms ranging to August 2020.

At December 31, 2019, our share of potential exposure under the Sur de Texas pipeline guarantees was estimated to be $109 million with a carrying amount of less than $1 million.

Bruce Power

We and our joint venture partner on Bruce Power, BPC Generation Infrastructure Trust, have each severally guaranteed certain contingent financial obligations of Bruce Power related to a lease agreement. The Bruce Power guarantee has a term to 2021.

At December 31, 2019, our share of the potential exposure under the Bruce Power guarantee was estimated to be $88 million with no carrying amount.

Other jointly-owned entities

We and our partners in certain other jointly-owned entities have also guaranteed (jointly, severally, jointly and severally, or exclusively) 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, 2019 to be approximately $100 million with a carrying amount of $10 million. In certain cases, if we make a payment that exceeds our ownership interest, the additional amount must be reimbursed by our partners.

OBLIGATIONS – PENSION AND OTHER POST-RETIREMENT PLANS

In 2020, we expect to make funding contributions of approximately $116 million for the defined benefit pension plans, approximately $7 million for other post-retirement benefit plans and approximately $62 million for the savings plan and defined contribution pension plans. In addition, we expect to provide an additional estimated $12 million letter of credit to the Canadian defined benefit plan for solvency funding requirements.

In 2019, we made funding contributions of $122 million to our defined benefit pension plans, $22 million for the other post-retirement benefit plans and $61 million for the savings plan and defined contribution pension plans. We also provided a $12 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, 2020. Based on current market conditions, we expect funding requirements for these plans to approximate 2020 levels for several years. This will allow us to amortize solvency deficiencies in the plans, in addition to normal funding costs.

The net benefit cost for our defined benefit and other post-retirement plans increased to $83 million in 2019 from $74 million in 2018 mainly due to lower discount rates.

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

ENTERPRISE 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 aligned with our business objectives and risk tolerance. We manage risk through a centralized enterprise risk management process that identifies risks that could materially impact the achievement of our strategic objectives. This includes ESG related risks.

Our Board of Directors' Governance Committee oversees our enterprise risk management activities, which includes ensuring appropriate management systems are in place to identify and manage our risks, ensuring 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 HSSE Committee oversees operational, health, safety, sustainability and environmental risk
- the Audit Committee oversees management's role in managing financial risk, including cyber security.

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 certain general risks that affect our company and are being continuously monitored. 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 equipment malfunctions and breakdowns, labour disputes, or natural disasters and other catastrophic events, including those related to climate change, acts of terror and sabotage.	Decrease in revenues and increase in operating costs, legal proceedings or regulatory actions, or other expenses all of which could reduce our earnings. Losses not recoverable through tolls or contracts or covered by insurance could have an adverse effect on operations, cash flows and financial position. Certain events could lead to risk of injury and environmental damage.	We have TOMS that includes our corporate health, safety, environment and asset integrity programs to prevent incidents and protect people, the environment and our assets. TOMS includes incident, emergency and crisis management programs to ensure TC Energy can effectively respond to operational risk events, minimize loss or injury and enhance our ability to resume operations. This is supported by our business continuity program that identifies critical business processes and develops corresponding business resumption plans. We also have a comprehensive insurance program to mitigate a certain portion of these risks, but insurance does not cover all events in all circumstances.
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, and/or result in 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 robust cyber security awareness program for employees. We have insurance which may cover losses from physical damage to our facilities as a result of a cyber security event, but insurance does not cover all events in all circumstances.

Risk and Description	Impact	Monitoring and Mitigation
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, as well as our access to and cost 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 our energy infrastructure business, future access to investment capital could be negatively impacted.	Our four core values – safety, responsibility, collaboration and integrity – 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 facilitate compliance with legal and policy requirements. Our Report on Sustainability and Climate Change was informed by the TCFD reporting framework.
Access to capital at a competitive cost		
We require substantial amounts of capital in the form of debt and equity to finance our portfolio of growth projects and maturing debt obligations at costs that are sufficiently lower than the returns on our investments.	Significant deterioration in market conditions for an extended period of time and changes in investor and lender sentiment could affect our ability to access capital at a competitive cost, which could negatively impact our ability to deliver an attractive return on our investments.	We operate within our financial means and risk tolerances, maintain a diverse array of funding levers and also utilize portfolio management as an important component of our financing program. In addition, we have candid and proactive engagement with the investment community, including credit rating agencies, with the objective of keeping them apprised of developments in our business and factually communicating our prospects, risks and challenges, including those related to ESG.
Capital allocation strategy		
To be competitive, we must offer energy infrastructure services in supply and demand areas, and for forms of energy that are attractive to customers.	Should alternative lower-carbon forms of energy result in decreased demand for our current services, the value of our long-lived energy infrastructure assets could be negatively impacted.	We have a diverse portfolio of assets and we utilize portfolio management to divest of non-strategic assets. We conduct analyses to identify resilient supply basins as part of our energy fundamentals and strategic development reviews. We also monitor the development of innovative technologies to inform our capital allocation strategy.
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 determine the expected cost of our capital projects, under some commercial arrangements 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 TOMS which provides the framework and standards to optimize project execution, ensuring timely and on budget completion. We prefer to contractually structure our projects to recover development costs if a project does not proceed along with mechanisms to minimize the impact should cost overruns occur. However, under some commercial arrangements, we share or bear the cost of execution risk. Additionally, we can utilize project financing and/or involve partners in our projects to advance funding plans.

Health, safety, sustainability and environment

The Board's HSSE Committee oversees operational risk, people and process safety, security of personnel, environmental and climate change related risks, and monitors development and implementation of systems, programs and policies relating to HSSE matters through regular reporting from management. We use an integrated management system that establishes a framework for managing these risks and is used to capture, organize, document, monitor and improve our related policies, programs and procedures.

Our management system, TOMS, is modeled after international standards, including the International Organization for Standardization (ISO) standard for environmental management systems, ISO 14001, and the Occupational Health and Safety Assessment Series for occupational health and safety. TOMS conforms to applicable industry standards and complies with applicable regulatory requirements. It covers our projects and operations and follows a continuous improvement cycle organized into four key areas:

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

The HSSE Committee reviews HSSE performance and operational risk management. It receives detailed reports on:

- overall HSSE 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
- prevention, mitigation and management of risks related to HSSE matters, including climate change related risks that may adversely impact TC Energy
- sustainability matters, including social, environmental and climate change related risks and opportunities
- our Health and Industrial Hygiene Program
- management's approach to voluntary public disclosure on HSSE matters.

Health, safety and asset integrity

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

In 2019, we spent $1.3 billion for pipeline integrity on the natural gas and liquids pipelines we operate, which was consistent with 2018. 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, incidents and maintenance activities.

Under the approved regulatory models in Canada, non-capital pipeline integrity expenditures on CER-regulated natural gas pipelines are generally treated on a flow-through basis and, as a result, fluctuations in these expenditures generally have no impact on our earnings. Similarly, under our Keystone Pipeline System contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, generally have no impact on our earnings. Non-capital pipeline integrity expenditures on our U.S. natural gas pipelines are primarily treated as operations and maintenance expenditures, and are typically recoverable through tolls approved by FERC.

Spending associated with process safety and various integrity programs for the power and storage assets we operate is used to minimize risk to employees, the public, equipment, and 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.

We are committed to protecting the health and safety of all individuals involved in our activities as well as the communities where we live and work. Our Health and Industrial Hygiene Program provides comprehensive strategies for health promotion and protection. We are committed to delivering effective programs that:

- reduce the human and financial impact of illness and injury
- ensure fitness for work
- strengthen worker resiliency
- build organizational capacity by focusing on individual well-being, health education and improved working conditions to sustain a productive workforce.

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. As part of our Environment Program, we complete environmental assessments for our projects. The environmental assessment includes field studies that examine existing natural resources, biodiversity and land use along our proposed project footprint such as vegetation, soils, wildlife, water resources, wetland, and protected areas. To conserve and protect the environment during construction, information gathered for an environmental impact assessment is used to develop project-specific environmental protection plans. Additionally, the Environment Program includes practices and procedures to manage potential adverse environmental effects to these resources during operations.

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 as well as 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 for compliance with all material legal and regulatory environmental requirements across all jurisdictions where we operate. We also comply with all material legal and regulatory permitting requirements in our project routing and development. 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.

Other than as noted in the Liquids Pipelines Significant events section, 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 their interpretations and enforcement 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 investigations or agreements
- new contaminated sites may be found, 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, 2019, accruals related to these obligations totaled $29 million (2018 – $32 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 2019, we incurred $69 million (2018 – $62 million) of expenses 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 promote sustainable and economically responsible natural resource development. 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

Canadian Jurisdiction

- ECCC issued the final Methane Reduction Regulation in April 2018. The regulations detail requirements to reduce methane emissions through operational and capital modifications. There are multiple time frames for compliance depending on the provision, beginning in 2020. Alberta, British Columbia and Saskatchewan have drafted their own methane regulations that take the place of the federal regulation in those jurisdictions. However, for the federally-regulated facilities in these jurisdictions, the federal methane regulation will be applicable. For most of TC Energy's Canadian pipeline assets, it is likely that the federal regulation will be applicable. Compliance will involve equipment retrofits, frequent leak detection and repair surveys and measurements to quantify emission reductions and associated reporting. Power facilities are not affected by this regulation
- the Government of Canada has finalized a Federal plan to have carbon pricing in place in all Canadian jurisdictions. ECCC finalized the Federal OBPS regulation to impose carbon pricing for larger industrial facilities and set federal benchmarks for GHG emissions for various industry sectors. This federal regulation will apply to the provinces of Ontario, Manitoba, Saskatchewan, and New Brunswick as those jurisdictions do not currently have a provincial plan in place for carbon pricing or meet the criteria of the Federal plan. This may result in increased costs for current pipeline and power and storage facilities in those jurisdictions
- B.C. has a tax on GHG emissions from fossil fuel combustion. We recover the compliance costs through our tolls. B.C. has established The CleanBC Program for industry which will direct a portion of B.C.'s carbon tax paid by industry to incentives for cleaner operations by means of performance benchmarking or funding emissions reduction projects
- in Alberta, the CCIR replaced the SGER effective January 2018. This regulation requires established industrial facilities with GHG emissions above a certain threshold to reduce their emissions below an intensity baseline. The CCIR covers our natural gas pipelines and certain power and storage assets in Alberta. Canadian natural gas pipeline compliance costs are recovered through regulated tolls. A portion of the compliance costs for the Power and Storage assets are recovered through market pricing and hedging activities. The existing CCIR has been replaced with the Technology Innovation and Emissions Reduction (TIER) regulation as of January 1, 2020. The TIER system follows a similar regulatory framework as the CCIR and will cover all of our natural gas pipelines, power and storage assets in the province. In December 2019, the Government of Canada announced that Alberta's TIER regulation meets the federal government's criteria for carbon-pollution pricing systems for the emission sources it covers
- Québec has a GHG cap-and-trade program 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 are recovered through commercial contracts. The Canadian Mainline natural gas pipeline facilities in Québec are also subject to this program and compliance instruments have been purchased in order to comply with the requirements of this initiative

- Ontario repealed its cap-and-trade program in 2018. The compliance credits purchased under the previous cap-and-trade program have been retired by the new government. With the repeal of the cap-and-trade program, Ontario does not currently have carbon pricing regulation, therefore, TC Energy's electricity and pipeline facilities in this jurisdiction are subject to the Canadian Federal OBPS as of January 1, 2019. The Government of Ontario is in the process of developing a provincial industrial carbon pricing program, the Emissions Performance Standards (EPS). The Ontario EPS system will not be implemented until Ontario receives equivalency status from the federal government. Until that time, Federal OBPS applies to electric generation facilities with annual emissions greater than 50,000 tonnes of CO_2 equivalent. At this time, we do not anticipate any material impact to the financial performance of our Ontario natural gas facilities as a result of this program.

U.S. Jurisdiction

- At a Federal level, 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. In 2018, with direction from the current administration, the EPA began working on reducing the requirements of this regulation. No amendments have been published to date
- In March 2017, the California Air Resources Board published regulations related to monitoring and repairing methane leaks. Tuscarora facilities are required to comply with these regulations. Beginning January 1, 2020, leak thresholds which require repair will be reduced and could increase operating costs for Tuscarora facilities
- California has a GHG cap-and-trade program under the WCI GHG emissions market. In California, TC Energy incurs costs associated with the cap-and-trade program with respect to our electricity marketing activities
- Washington State adopted emission standards to cap and reduce GHGs from certain stationary sources in September 2016. This bill did not receive committee approval in 2019 and no impacts to our facilities are currently anticipated
- the Pennsylvania Department of Environmental Protection has adopted new operating permits for certain types of new oil and gas facilities that include numerous requirements including methane leak detection and repair. TC Energy does not have facilities within the scope of these requirements and therefore does not anticipate any impacts
- The Oregon Department of Environmental Quality has begun rolling out the 2018 Cleaner Air Oregon program to regulate air emissions of certain permit holders. The GTN compressor stations in Oregon may be impacted, however, it is expected to be several years before the GTN facilities are required to comply with the program.

Mexico Jurisdiction

- In November 2018, the Government of Mexico published a new regulation that established guidelines for the prevention and control of methane emissions in the hydrocarbon sector, which will impact our Mexico natural gas pipelines. Companies are required to prepare a Program for the Comprehensive Prevention and Control of Methane Emissions (PPCIEM) which includes identification of sources of methane, quantification of baseline emissions, and an estimate of the expected emission reductions from prevention and control activities. Each company is required to set a reduction goal as part of the PPCIEM and is expected to meet the reduction goal within a period not exceeding six calendar years from the delivery of the PPCIEM. The deadline for submission of the PPCIEM is February 28, 2020.

Anticipated policies

- the Government of Canada has proposed a Federal plan, the Clean Fuel Standard (CFS), to implement a single national standard encompassing all fuel types and applications. As part of the CFS, compressor station electrification and renewable natural gas or hydrogen blending are proposed by the Federal Government as a mechanism to reduce natural gas transmission GHG emissions. These could have negative impacts to our Canadian natural gas compression assets. Efforts to influence this policy are being managed through CEPA and CGA. Different components of the CFS regulations are expected to be released through early 2020
- the Government of Saskatchewan has announced that certain large industrial emitters will be subject to a provincially proposed carbon pricing system based on an OBPS approach, which has potential to impact our Canadian natural gas pipelines in that province. This proposed system only partially meets the Federal plan and, therefore, the Federal OBPS will apply to emission sources not covered by the proposed system, including electricity generation and natural gas pipelines
- New York State announced its intent to adopt regulations to reduce methane from existing, new and modified facilities. New York has not yet proposed regulations, but the Governor announced the State's plan to achieve its clean energy goals by 2030, which includes a 40 per cent reduction from 1990 emissions levels. Impacts to our facilities are dependent on the specifics of the regulations once they are proposed, but it is likely that our compression facilities in New York State would be affected

- It is expected that Maryland will finalize its methane regulations in spring or summer 2020. TC Energy has only one compressor station in Maryland, and the current details within the regulation will require annual leak detection and repair as well as blowdown reporting and notification at the station
- The state of Virginia is in the process of collecting stakeholder input regarding methane regulations, but details of the draft regulations have not been released. We will monitor the progress of these regulations and submit comments to regulators as needed
- In Washington State, a bill proposing that Washington's electricity grid be 80 per cent fossil free by 2030 and 100 per cent fossil free by 2045 passed the 2019 legislative session. There is not enough information at this time to understand the potential cost and revenue impacts to TC Energy's facilities in Washington
- In Oregon, proposed cap and trade legislation was reintroduced in 2019 as a legislative initiative to regulate GHG emissions. It was unsuccessful in 2018, and in 2019 it has been met with significant public opposition and did not pass the State Senate. It is expected to be revisited in 2020, however, potential impacts to our facilities in Oregon are not yet known.

Changes to Environmental Assessment Legislation

On August 28, 2019, following the passage of Bill C-69, the IA Act, the CER Act and the Canadian Navigable Waters Act came into effect. The majority of our natural gas and liquids pipeline assets in operation in Canada are federally regulated and will remain regulated by the CER under the CER Act. New projects that will be regulated by the CER require an environmental and socio-economic assessment, with additional provisions not previously required by the NEB. Refer to the Significant events section in the Canadian Natural Gas Pipelines segment for additional information.

A limited number of our natural gas and liquids pipeline assets are provincially regulated in Alberta and B.C. In B.C. there are policy and regulatory initiatives currently underway related to an environmental impact assessment. We have been actively monitoring and submitting comments to regulators.

Financial risks

We are exposed to market risk and counterparty credit risk and have strategies, policies and limits in place to manage the impact of these risks on our earnings, cash flows and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance. Market risk and counterparty credit risk are managed within limits that are established by our Board of Directors, implemented by senior management and monitored by our risk management and internal audit groups. Our Board of Directors' Audit Committee oversees how management monitors compliance with market risk and counterparty credit risk management policies and procedures and oversees management's review of the adequacy of the risk management framework.

Market risk

We construct and invest in energy infrastructure projects, purchase and sell 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 used to assist in managing our exposure to market risk may include the following:
- forwards and futures contracts – agreements to purchase or sell a specific 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 convey the right, but not the obligation of the purchaser, to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period.

Commodity price risk

The following strategies may be used to manage exposure to commodity price risk in our non-regulated businesses:
- in our power generation business, we manage our exposure to fluctuating commodity prices through long-term contracts and hedging activities including selling and purchasing power and natural gas in forward markets
- in our non-regulated natural gas storage business, our exposure to seasonal natural gas price spreads is managed with a portfolio of third-party storage capacity contracts and through offsetting purchases and sales of natural gas in forward markets to lock in future positive margins
- in our liquids marketing business, we enter into pipeline and storage terminal capacity contracts, as well as crude oil purchase and sale agreements. We fix a portion of our exposure on these contracts by entering into financial instruments to manage our variable price fluctuations that arise from physical liquids transactions.

In May 2019, we sold our remaining U.S. Power marketing contracts which completed the divestiture of our U.S. Northeast power business which began in 2017, greatly reducing our exposure to electricity price risk.

Lower crude oil, natural gas, and electricity prices could lead to reduced investment in the development and expansion of these commodities. A reduction in the supply of these commodities could negatively impact opportunities to expand our asset base and re-contract with our shippers and customers as their contractual agreements expire.

Climate change also presents a potential financial impact to commodity prices and volumes. Our exposure to climate change risk and resulting policy changes is managed through our business model which is based on a long-term, low-risk strategy whereby the majority of our earnings are underpinned by regulated cost-of-service arrangements and long-term contracts. In addition, scenario planning against several demand outlooks is also considered as part of our long-term corporate strategic planning process.

Interest rate risk

We utilize short-term and long-term debt to finance our operations which exposes us to interest rate risk. We typically pay fixed rates of interest on our long-term debt and floating rates on our commercial paper programs and amounts drawn on our credit facilities. A small portion of our long-term debt bears interest at floating rates. In addition, we are exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. We actively manage our interest rate risk using interest rate swaps.

Many of our financial instruments and contractual obligations with variable rate components reference LIBOR. This rate will cease to be published at the end of 2021 and will likely be replaced by a secured overnight financing rate. We will continue to monitor developments and the impact, if any, on our business.

Foreign exchange risk

We generate revenues and incur expenses and capital expenditures 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. A portion of this risk is offset by interest expense on U.S. dollar-denominated debt. The balance of the exposure is actively managed on a rolling one-year basis using foreign exchange derivatives, however, the natural exposure beyond that period remains.

Average exchange rate – U.S. to Canadian dollars

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

2019	**1.33**
2018	1.30
2017	1.30

The impact of changes in the value of the U.S. dollar on our U.S. and Mexico operations is partially offset by interest on U.S. dollar-denominated debt as set out in the table below. Comparable EBIT is a non-GAAP measure. Refer to our Reconciliation of non-GAAP measures section for more information.

Significant U.S. dollar-denominated amounts

year ended December 31 (millions of US$)	**2019**	**2018**	**2017**
U.S. Natural Gas Pipelines comparable EBIT	**2,055**	1,830	1,360
Mexico Natural Gas Pipelines comparable EBIT[1]	**481**	486	353
U.S. Liquids Pipelines comparable EBIT	**1,127**	876	604
U.S. Power comparable EBIT[2]	**—**	—	100
Interest on U.S. dollar-denominated long-term debt and junior subordinated notes	**(1,326)**	(1,325)	(1,269)
Capitalized interest on U.S. dollar-denominated capital expenditures	**34**	15	3
U.S. dollar-denominated allowance for funds used during construction	**205**	326	259
U.S. dollar comparable non-controlling interests and other	**(233)**	(264)	(195)
	2,343	1,944	1,215

1 Excludes interest expense on our inter-affiliate loan with Sur de Texas which is offset in Interest income and other.
2 Effective January 2018, U.S. Power is no longer included in comparable EBIT.

Net investment hedges

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

Counterparty credit risk

We have exposure to counterparty credit risk in the following areas:
- cash and cash equivalents
- accounts receivable
- available-for-sale assets
- the fair value of derivative assets
- a loan receivable.

During the year, continued low natural gas prices presented increased financial challenges for some of our natural gas shippers that resulted in restructuring and bankruptcy for certain shipper entities, with no significant negative impact to our 2019 earnings or cash flows.

We monitor counterparties and review our accounts receivable regularly and, if needed, we record allowances for doubtful accounts using the specific identification method. At December 31, 2019 and 2018, we had no significant credit losses, no significant credit risk concentration and no significant amounts past due or impaired.

At times, our counterparties may endure financial challenges resulting from commodity price and market volatility, economic instability and political or regulatory changes. In addition to actively monitoring these situations, there are a number of factors that reduce our counterparty credit risk exposure in the event of default, including:

- contractual rights and remedies together with the utilization of contractually-based financial assurances
- current regulatory frameworks governing certain of our operations
- the competitive position of our assets and the demand for our services
- potential recovery of unpaid amounts through bankruptcy and similar proceedings.

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

Liquidity risk

Liquidity risk is the risk that we will not be able to meet our financial obligations as they come due. We manage our liquidity by continuously forecasting our cash flows and making sure we have adequate cash balances, cash flows 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. Refer to the Financial condition section for more information about our liquidity.

Loan receivable from affiliate

We hold a 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline. In 2017, we entered into a MXN 21.3 billion unsecured revolving credit facility with the joint venture, which bears interest at a floating rate and matures in March 2022. At December 31, 2019, our Consolidated balance sheet included a MXN 20.9 billion or $1.4 billion (2018 – MXN 18.9 billion or $1.3 billion) loan receivable from the Sur de Texas joint venture which represents our proportionate share of long-term debt financing to the joint venture. Interest income and other included interest income of $147 million in 2019 (2018 – $120 million; 2017 – $34 million) from this joint venture, with a corresponding proportionate share of interest expense recorded in Income from equity investments in our Mexico Natural Gas Pipelines segment. Interest income and other also included foreign exchange gains of $53 million in 2019 (2018 - losses of $5 million; 2017 - losses of $63 million) from this joint venture with a corresponding proportionate share of Sur de Texas foreign exchange gains and losses recorded in Income from equity investments in the Corporate segment. As a result, there is no impact to net income.

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, 2019, 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, 2019, 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, 2019, the internal control over financial reporting was effective.

Our internal control over financial reporting as of December 31, 2019 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 2019 reports filed with Canadian securities regulators and the SEC and have filed certifications with them.

Changes in internal control over financial reporting

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 significant assumptions based on factors that are either subjective or highly uncertain when preparing our financial statements and changes in these assumptions could have a material impact on the financial statements. Our accounting policies disclose the critical accounting estimates we make when preparing our financial statements.

Impairment of long-lived assets and goodwill

We review long-lived assets, such as plant, property and equipment, equity investments and capital projects in development, for impairment whenever events or changes in circumstances lead us to believe we might not be able to recover an asset's carrying value. Factors we consider in our assessment of the recoverability of long-lived assets include, but are not limited to, macroeconomic conditions, changes in the industries and markets in which we operate, our ability to renew contracts, and the financial performance and prospects of our assets. If the total of the undiscounted future cash flows that we estimate for an asset within Property, plant and equipment, or the estimated selling price of any long-lived asset is less than its carrying value, we consider its fair value to be less than its carrying value and record an impairment loss to recognize this. For goodwill, if the fair value of the reporting unit determined using discounted cash flows is less than its carrying value, we consider it to be impaired.

In 2019, no impairments were recorded.

In 2018, the following impairments were recorded:

- a $722 million pre-tax impairment of the carrying value of our investment in Bison ($140 million after tax and net of non-controlling interests)
- a $79 million pre-tax impairment of the carrying value of Tuscarora's goodwill ($15 million after tax and net of non-controlling interests).

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.

Long-lived assets

Bison

In December 2018, we evaluated our investment in the Bison natural gas pipeline for impairment in connection with the termination of certain customer transportation agreements. With the loss of these contracted future cash flows, and the persistence of unfavourable market conditions which have inhibited system flows on the pipeline, we determined that the asset’s remaining carrying value was no longer recoverable and recognized a non-cash impairment charge of $722 million in the U.S. Natural Gas Pipelines segment. Our share of the impairment charge, after tax and net of non-controlling interests, was $140 million.

Energy East and related projects

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 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.

Energy Turbine Equipment

In December 2017, we recognized a non-cash impairment charge of $16 million after tax related to the 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.

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.

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 initially assess qualitative factors which include, but are not limited to, macroeconomic conditions, industry and market considerations, cost factors, historical and forecasted financial results, or events specific to that reporting unit. 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 will then perform a quantitative goodwill impairment test. We can elect to proceed directly to the quantitative goodwill impairment test for any reporting unit. If the quantitative goodwill impairment test is performed, we compare the fair value of the reporting unit to its carrying value, including its goodwill. If the carrying value of a reporting unit exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value.

When a portion of a reporting unit that constitutes a business is disposed, goodwill associated with that business is included in the carrying amount of the business in determining the gain or loss on disposal. The amount of goodwill disposed is determined based on the relative fair values of the business to be disposed and the portion of the reporting unit that will be retained. On August 1, 2019, we completed the sale of certain Columbia midstream assets to a third party. As these assets constitute a business within the Columbia reporting unit, $595 million of Columbia's goodwill allocated to these assets was released and netted in the gain on sale.

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

As part of the annual goodwill impairment assessment, we evaluated qualitative factors impacting the fair value of the reporting units. It was determined that it was more likely than not that the fair value of the reporting units exceeded their carrying amounts, including goodwill, and therefore, goodwill was not impaired.

Tuscarora

In fourth quarter 2018, Tuscarora finalized its regulatory filing in response to the 2018 FERC Actions resulting in a reduction in its recourse rates and, in January 2019, reached a settlement-in-principle with its customers. As a result of these developments, as well as changes to other valuation assumptions responsive to Tuscarora's commercial environment, we determined that the fair value of Tuscarora did not exceed its carrying value, including goodwill, and recorded a goodwill impairment charge of $79 million within the U.S. Natural Gas Pipelines segment. Our share of the goodwill impairment charge, after-tax and net of non-controlling interests, was $15 million. Our share of the remaining goodwill balance related to Tuscarora, net of non-controlling interests, was US$6 million at December 31, 2019 (2018 – US$6 million).

FINANCIAL 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 and are classified as 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, are expected to 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.

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 $)	2019	2018
Other current assets	**190**	737
Intangible and other assets	**7**	61
Accounts payable and other	**(115)**	(922)
Other long-term liabilities	**(81)**	(42)
	1	(166)

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, 2019 (millions of $)	Total fair value	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Derivative instruments held for trading					
Assets	179	179	—	—	—
Liabilities	(118)	(107)	(4)	—	(7)
Derivative instruments in hedging relationships					
Assets	18	11	3	3	1
Liabilities	(78)	(8)	(31)	(14)	(25)
	1	75	(32)	(11)	(31)

Unrealized and realized (losses)/gains on derivative instruments

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

year ended December 31 (millions of $)	2019	2018	2017
Derivative instruments held for trading[1]			
Amount of unrealized (losses)/gains in the year			
Commodities[2]	**(111)**	28	62
Foreign exchange	**245**	(248)	88
Interest rate	**—**	—	(1)
Amount of realized gains/(losses) in the year			
Commodities	**378**	351	(107)
Foreign exchange	**(70)**	(24)	18
Interest rate	**—**	—	1
Derivative instruments in hedging relationships			
Amount of realized (losses)/gains in the year			
Commodities	**(6)**	(1)	23
Foreign exchange	**—**	—	5
Interest rate	**2**	(1)	1

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

2 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.

For further details on our non-derivative and derivative financial instruments, including classification assumptions made in the calculation of fair value and additional discussion of exposure to risks and mitigation activities, refer to Note 25, Risk management and financial instruments, in our Consolidated financial statements.

ACCOUNTING CHANGES

For a description of our significant accounting policies and a summary of changes in accounting policies and standards impacting our business please refer to Note 2, Accounting policies, and Note 3, Accounting changes, in our Consolidated financial statements.

QUARTERLY RESULTS

Selected quarterly consolidated financial data

(millions of $, except per share amounts)

2019	Fourth	Third	Second	First
Revenues	**3,263**	**3,133**	**3,372**	**3,487**
Net income attributable to common shares	**1,108**	**739**	**1,125**	**1,004**
Comparable earnings	**970**	**970**	**924**	**987**
Share statistics:				
Net income per common share – basic and diluted	**$1.18**	**$0.79**	**$1.21**	**$1.09**
Comparable earnings per common share	**$1.03**	**$1.04**	**$1.00**	**$1.07**
Dividends declared per common share	**$0.75**	**$0.75**	**$0.75**	**$0.75**

2018	Fourth	Third	Second	First
Revenues	3,904	3,156	3,195	3,424
Net income attributable to common shares	1,092	928	785	734
Comparable earnings	946	902	768	864
Share statistics:				
Net income per common share – basic and diluted	$1.19	$1.02	$0.88	$0.83
Comparable earnings per common share	$1.03	$1.00	$0.86	$0.98
Dividends declared per common share	$0.69	$0.69	$0.69	$0.69

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
- newly constructed assets being placed in service
- acquisitions and divestitures
- developments outside of the normal course of operations.

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

- regulatory decisions
- newly constructed assets being placed in service
- acquisitions and divestitures
- demand for uncontracted transportation services
- liquids marketing activities
- developments outside of the normal course of operations
- certain fair value adjustments.

In Power and Storage, quarter-over-quarter revenues and net income are affected by:
- weather
- customer demand
- newly constructed assets being placed in service
- acquisitions and divestitures
- market prices for natural gas and power
- capacity prices and payments
- planned and unplanned plant outages
- developments outside of the normal course of operations
- certain fair value adjustments.

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 2019, comparable earnings also excluded:
- a valuation allowance release of $195 million related to certain prior years' U.S. tax losses resulting from our reassessment of deferred tax assets that are more likely than not to be realized
- an incremental after-tax loss of $61 million related to the Ontario natural gas-fired power plant assets held for sale
- an additional $19 million expense related to state income taxes on the sale of certain Columbia midstream assets.

In third quarter 2019, comparable earnings also excluded:
- an after-tax loss of $133 million related to the Ontario natural gas-fired power plant assets held for sale
- an after-tax loss of $133 million related to the sale of certain Columbia midstream assets
- an after-tax gain of $115 million related to the partial sale of Northern Courier.

In second quarter 2019, comparable earnings also excluded:
- an after-tax gain of $54 million related to the sale of our Coolidge generating station
- a deferred tax benefit of $32 million related to the impact of an Alberta corporate income tax rate reduction on our Canadian businesses not subject to RRA
- an after-tax gain of $6 million related to the remainder of our U.S. Northeast power marketing contracts.

In first quarter 2019, comparable earnings also excluded:
- an after-tax loss of $12 million related to our U.S. Northeast power marketing contracts.

In fourth quarter 2018, comparable earnings also excluded:
- a $143 million after-tax gain related to the sale of our interests in the Cartier Wind power facilities
- a $115 million deferred income tax recovery from an MLP regulatory liability write-off as a result of the 2018 FERC Actions
- a $52 million recovery of deferred income taxes as a result of finalizing the impact of U.S. Tax Reform
- a $27 million income tax recovery related to the sales of our U.S. Northeast power generation assets
- $25 million of after-tax income recognized on the Bison contract terminations
- a $140 million after-tax impairment charge on Bison
- a $15 million after-tax goodwill impairment charge on Tuscarora
- an after-tax net loss of $7 million related to our U.S. Northeast power marketing contracts.

In third quarter 2018, comparable earnings also excluded:
- an after-tax gain of $8 million related to our U.S. Northeast power marketing contracts.

In second quarter 2018, comparable earnings also excluded:

- an after-tax loss of $11 million related to our U.S. Northeast power marketing contracts.

In first quarter 2018, comparable earnings also excluded:

- an after-tax gain of $6 million related to our U.S. Northeast power marketing contracts.

FOURTH QUARTER 2019 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	2019	2018
Canadian Natural Gas Pipelines	**321**	450
U.S. Natural Gas Pipelines	**666**	(34)
Mexico Natural Gas Pipelines	**136**	128
Liquids Pipelines	**355**	532
Power and Storage	**102**	315
Corporate	**(69)**	23
Total segmented earnings	**1,511**	1,414
Interest expense	**(586)**	(603)
Allowance for funds used during construction	**117**	161
Interest income and other	**210**	(215)
Income before income taxes	**1,252**	757
Income tax expense	**(27)**	(38)
Net income	**1,225**	719
Net (income)/loss attributable to non-controlling interests	**(76)**	414
Net income attributable to controlling interests	**1,149**	1,133
Preferred share dividends	**41**	41
Net income attributable to common shares	**1,108**	1,092
Net income per common share – basic and diluted	**$1.18**	$1.19

Net income attributable to common shares increased by $16 million and decreased by $0.01 per common share for the three months ended December 31, 2019 compared to the same period in 2018. Net income per common share reflects the dilutive impact of common shares issued under our DRP in fourth quarter 2018 and throughout 2019.

Net income included unrealized gains and losses from changes in risk management activities which we excluded along with other specific items as noted below to arrive at comparable earnings.

Fourth quarter 2019 results included:

- a valuation allowance release of $195 million related to certain prior years' U.S. tax losses resulting from our reassessment of deferred tax assets that are more likely than not to be realized
- an incremental after-tax loss of $61 million related to the Ontario natural gas-fired power plant assets held for sale resulting in a total accrued after-tax loss of $194 million at December 31, 2019. The total after-tax loss on this sale is expected to be $280 million. The unrecorded portion of this loss at December 31, 2019 primarily reflects the residual costs expected to be incurred until Napanee is placed in service, including capitalized interest as well as expected closing adjustments, and will be recorded on or before closing of this transaction. Closing is anticipated by the end of first quarter 2020
- an additional $19 million expense related to state income taxes on the sale of certain Columbia midstream assets.

Fourth quarter 2018 results included:

- a $143 million after-tax gain related to the sale of our interests in the Cartier Wind power facilities
- a $115 million deferred income tax recovery from an MLP regulatory liability write-off as a result of the 2018 FERC Actions
- a $52 million recovery of deferred income taxes as a result of finalizing the impact of U.S. Tax Reform
- a $27 million income tax recovery related to the sales of our U.S. Northeast power generation assets
- $25 million of after-tax income recognized on the Bison contract terminations
- a $140 million after-tax impairment charge on Bison
- a $15 million after-tax goodwill impairment charge on Tuscarora
- an after-tax net loss of $7 million related to our U.S. Northeast power marketing contracts.

Reconciliation of net income to comparable earnings

three months ended December 31 (millions of $, except per share amounts)	2019	2018
Net income attributable to common shares	**1,108**	1,092
Specific items (net of tax):		
U.S. valuation allowance release	**(195)**	—
Loss on Ontario natural gas-fired power plants held for sale	**61**	—
Loss on sale of Columbia midstream assets	**19**	—
Gain on sale of Cartier Wind power facilities	**—**	(143)
MLP regulatory liability write-off	**—**	(115)
U.S. Tax Reform	**—**	(52)
Net gain on sales of U.S. Northeast power generation assets	**—**	(27)
Bison contract terminations	**—**	(25)
Bison asset impairment	**—**	140
Tuscarora goodwill impairment	**—**	15
U.S. Northeast power marketing contracts	**—**	7
Risk management activities[1]	**(23)**	54
Comparable earnings	**970**	946
Net income per common share	**$1.18**	$1.19
Specific items (net of tax):		
U.S. valuation allowance release	**(0.21)**	—
Loss on Ontario natural gas-fired power plants held for sale	**0.07**	—
Loss on sale of Columbia midstream assets	**0.02**	—
Gain on sale of Cartier Wind power facilities	**—**	(0.16)
MLP regulatory liability write-off	**—**	(0.13)
U.S. Tax Reform	**—**	(0.06)
Net gain on sales of U.S. Northeast power generation assets	**—**	(0.03)
Bison contract terminations	**—**	(0.03)
Bison asset impairment	**—**	0.16
Tuscarora goodwill impairment	**—**	0.02
U.S. Northeast power marketing contracts	**—**	0.01
Risk management activities[1]	**(0.03)**	0.06
Comparable earnings per common share	**$1.03**	$1.03

1

three months ended December 31 (millions of $)	2019	2018
Liquids marketing	**(36)**	81
Canadian power	**1**	—
U.S. power	**—**	20
Natural gas storage	**(3)**	(5)
Foreign exchange	**69**	(169)
Income taxes attributable to risk management activities	**(8)**	19
Total unrealized gains/(losses) from risk management activities	**23**	(54)

Comparable EBITDA to comparable earnings

Comparable EBITDA represents segmented earnings adjusted for certain aspects of the specific items described above and excludes non-cash charges for depreciation and amortization.

three months ended December 31 (millions of $)	2019	2018
Comparable EBITDA		
Canadian Natural Gas Pipelines	**618**	818
U.S. Natural Gas Pipelines	**855**	812
Mexico Natural Gas Pipelines	**165**	152
Liquids Pipelines	**472**	538
Power and Storage	**210**	167
Corporate	**(5)**	(34)
Comparable EBITDA	**2,315**	2,453
Depreciation and amortization	**(625)**	(681)
Interest expense	**(586)**	(603)
Allowance for funds used during construction	**117**	161
Interest income and other included in comparable earnings	**77**	11
Income tax expense included in comparable earnings	**(211)**	(268)
Net income attributable to non-controlling interests included in comparable earnings	**(76)**	(86)
Preferred share dividends	**(41)**	(41)
Comparable earnings	**970**	946

Comparable EBITDA – 2019 versus 2018

Comparable EBITDA decreased by $138 million for the three months ended December 31, 2019 compared to the same period in 2018 primarily due to the net effect of the following:

- lower contribution from Canadian Natural Gas Pipelines primarily reflecting lower flow-through income taxes and depreciation as well as lower incentive earnings in the Canadian Mainline due to recording the full-year impact of the NEB 2018 Decision in fourth quarter 2018
- lower contribution from Liquids Pipelines primarily due to decreased volumes on the Keystone Pipeline System, lower margins on liquids marketing activities and the impact of the sale of an 85 per cent equity interest in Northern Courier on July 17, 2019
- higher contribution from U.S. Natural Gas Pipelines mainly due to incremental earnings from Columbia Gas growth projects placed in service, partially offset by decreased earnings from the sale of certain Columbia midstream assets on August 1, 2019 and from Bison following a 2018 agreement with two customers to pay out their future contract revenues and terminate the contracts
- higher contribution from Power and Storage primarily due to increased Bruce Power results from a higher realized power price and higher volumes, partially offset by lower results from our Alberta cogeneration plants and the sale of the Coolidge generating station on May 21, 2019
- higher equity earnings from our investment in the Sur de Texas pipeline which was placed in service in September 2019, at which time we began recording equity income from operations. Prior to in-service, Sur de Texas equity income primarily reflected AFUDC, net of our proportionate share of interest expense on inter-affiliate loans. This interest expense is fully offset in Interest income and other in the Corporate segment.

Due to the flow-through treatment of certain expenses including income taxes and depreciation on our Canadian rate-regulated pipelines, the decrease in these expenses impacts our comparable EBITDA despite having no significant effect on net income.

Comparable earnings – 2019 versus 2018

Comparable earnings increased by $24 million for the three months ended December 31, 2019 compared to the same period in 2018 primarily due to the net effect of:

- changes in comparable EBITDA described above
- higher interest income and other as a result of lower realized losses in 2019 compared to 2018 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- lower income tax expense primarily due to lower flow-through income taxes in Canadian rate-regulated pipelines and lower comparable earnings before income taxes, partially offset by lower foreign tax rate differentials
- lower depreciation largely in Canadian Natural Gas Pipelines which is fully recovered in tolls as reflected in comparable EBITDA above, therefore having no significant impact on comparable earnings. This was partially offset by increased depreciation in U.S. Natural Gas Pipelines reflecting new projects placed in service
- lower AFUDC primarily due to Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by capital expenditures on our NGTL System and continued investment in our Mexico projects.

Comparable earnings per common share for the three months ended December 31, 2019 was consistent with 2018 at $1.03 and reflects the dilutive impact of common shares issued under our DRP in fourth quarter 2018 and throughout 2019.

Highlights by business segment

Canadian Natural Gas Pipelines

Canadian Natural Gas Pipelines segmented earnings decreased by $129 million for the three months ended December 31, 2019 compared to the same period in 2018.

Net income for the NGTL System increased by $20 million for the three months ended December 31, 2019 compared to the same period in 2018 mainly due to a higher average investment base resulting from continued system expansions.

Net income for the Canadian Mainline decreased by $17 million for the three months ended December 31, 2019 compared to the same period in 2018 mainly due to lower net incentive earnings, partially offset by lower carrying charges on the 2019 revenue surplus. In December 2018, the NEB 2018 Decision was received and, as such, net incentive earnings for the full year of 2018 were recorded in fourth quarter 2018. The NEB 2018 Decision also included an accelerated amortization of the December 31, 2017 LTAA balance and an increase to the composite depreciation rate from 3.2 per cent to 3.9 per cent.

Comparable EBITDA decreased by $200 million for the three months ended December 31, 2019 compared to the same period in 2018 due to the net effect of:

- lower depreciation, income taxes and incentive earnings on the Canadian Mainline resulting from recording the full-year impact of the NEB 2018 Decision in fourth quarter 2018 which increased earnings in that quarter
- increased rate base earnings and depreciation on the NGTL System due to additional facilities that were placed in service.

Due to the flow-through treatment of income taxes and depreciation on our Canadian rate-regulated pipelines, changes in these items impact comparable EBITDA despite having no significant impact on net income.

Depreciation and amortization decreased by $71 million for the three months ended December 31, 2019 compared to the same period in 2018 mainly due to recording the full-year impact of higher depreciation rates approved in the Canadian Mainline NEB 2018 Decision in December 2018, partially offset by the additional NGTL System facilities that were placed in service.

U.S. Natural Gas Pipelines

U.S. Natural Gas Pipelines segmented earnings increased by $700 million for the three months ended December 31, 2019 compared to the same period in 2018 mainly due to the following specific items recorded in 2018 which are excluded from our calculation of comparable EBIT and comparable earnings:

- a $722 million pre-tax non-cash asset impairment charge related to Bison
- a $79 million pre-tax non-cash goodwill impairment charge related to Tuscarora
- $130 million of pre-tax customer termination payments that were recorded in Revenues with respect to two of Bison's transportation contracts.

Each of the specific items noted above are before reduction for the 74.5 per cent non-controlling interests in TC PipeLines, LP.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$35 million for the three months ended December 31, 2019 compared to the same period in 2018 which was primarily the net effect of:

- incremental earnings from Columbia Gas growth projects placed in service
- decreased earnings as a result of the sale of certain Columbia midstream assets on August 1, 2019
- decreased earnings from Bison following the 2018 customer agreements to pay out their future contracted revenues and terminate their contracts.

Depreciation and amortization increased by US$12 million for the three months ended December 31, 2019 compared to the same period in 2018 mainly due to new projects placed in service, partially offset by lower depreciation as a result of the Bison asset impairment in 2018 and the sale of certain Columbia midstream assets on August 1, 2019.

Mexico Natural Gas Pipelines

Mexico Natural Gas Pipelines segmented earnings increased by $8 million for the three months ended December 31, 2019 compared to the same period in 2018 principally due to increased EBITDA as described below.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$10 million for the three months ended December 31, 2019 compared to the same period in 2018 mainly due to the net effect of:

- higher equity earnings from our investment in the Sur de Texas pipeline which was placed in service in September 2019, at which time we began recording equity income from operations. Prior to in-service, Sur de Texas equity income reflected AFUDC, net of our proportionate share of interest expense on inter-affiliate loans. Our share of this interest expense is fully offset in Interest income and other
- lower revenues from other operations primarily as a result of changes in timing of revenue recognition in 2018.

Depreciation and amortization increased by US$3 million for the three months ended December 31, 2019 compared to the same period in 2018 reflecting new assets being placed in service and other adjustments.

Liquids Pipelines

Liquids Pipelines segmented earnings decreased by $177 million for the three months ended December 31, 2019 compared to the same period in 2018 and included unrealized gains and losses from changes in the fair value of derivatives related to our liquids marketing business which have been excluded from our calculation of comparable EBIT.

Comparable EBITDA for Liquids Pipelines decreased by $66 million for the three months ended December 31, 2019 compared to the same period in 2018. This was primarily the net effect of:

- lower volumes on the Keystone Pipeline System
- lower contribution from liquids marketing activities due to lower margins
- decreased earnings as a result of the sale of an 85 per cent equity interest in Northern Courier on July 17, 2019
- contribution from the White Spruce pipeline, which was placed in service in May 2019.

Depreciation and amortization decreased by $6 million for the three months ended December 31, 2019 compared to the same period in 2018 primarily as a result of the sale of an 85 per cent equity interest in Northern Courier.

Power and Storage

Power and Storage segmented earnings decreased by $213 million for the three months ended December 31, 2019 compared to the same period in 2018 and included the following specific items which have been excluded from comparable EBIT:

- an additional pre-tax loss in fourth quarter 2019 of $77 million related to the Ontario natural gas-fired power plant assets held for sale
- a pre-tax net loss in fourth quarter 2018 of $10 million related to U.S. Northeast power marketing contracts, the remainder of which were sold in May 2019
- a pre-tax gain in December 2018 of $170 million related to the sale of our interests in the Cartier Wind power facilities
- unrealized losses and gains from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks.

Comparable EBITDA for Power and Storage increased by $43 million for the three months ended December 31, 2019 compared to the same period in 2018 primarily due to the net effect of:

- increased Bruce Power results mainly due to a higher realized power price and higher volumes as a result of fewer outage days
- a lower Canadian Power contribution largely as a result of the sale of the Coolidge generating station on May 21, 2019, a prior period billing adjustment as well as greater outage days at our Alberta cogeneration plants.

Depreciation and amortization increased by $2 million for the three months ended December 31, 2019 compared to the same period in 2018 as a result of higher depreciation at our Alberta cogeneration plants due to a reassessment of the useful life of certain components. This increase was offset by the cessation of depreciation on our Halton Hills power plant at July 30, 2019 and on the Coolidge generating station at December 31, 2018 upon their classifications as held for sale.

Corporate

Corporate segmented earnings decreased by $92 million for the three months ended December 31, 2019 compared to the same period in 2018. Segmented (losses)/earnings within this period included foreign exchange losses of $64 million in 2019 compared to gains of $57 million in 2018 on our proportionate share of peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners. These amounts are recorded in Income from equity investments and have been excluded from our calculation of comparable EBITDA and EBIT as they are fully offset by corresponding foreign exchange gains and losses included in Interest income and other on the inter-affiliate loan receivable for our proportionate share of the project's long-term financing requirements.

Comparable EBITDA increased by $29 million for the three months ended December 31, 2019 compared to the same period in 2018 primarily due to higher general and administrative costs in 2018.

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
PJ/d	Petajoule per day
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
CEO	Chief Executive Officer
CFO	Chief Financial Officer
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
DRP	Dividend Reinvestment and Share Purchase Plan
ESG	Environmental, social and governance
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
HSSE	Health, safety, sustainability and environment
investment base	Includes rate base as well as assets under construction
LDC	Local distribution company
LNG	Liquefied natural gas
LTAA	Long Term Adjustment Account
MLP	Master limited partnership
OM&A	Operating, maintenance and administration
PPA	Power purchase arrangement
rate base	Average assets in service, working capital and deferred amounts used in setting of regulated rates
TOMS	TC Energy's Operational Management System
TSA	Transportation Service Agreement
WCSB	Western Canada Sedimentary basin

Accounting terms

AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive (loss)/income
FASB	Financial Accounting Standards Board (U.S.)
GAAP	U.S. generally accepted accounting principles
RRA	Rate-regulated accounting
ROE	Return on common equity

Government and regulatory bodies terms

AER	Alberta Energy Regulator
CCIR	Carbon Competitiveness Incentive Regulation
CEPA	Canadian Energy Pipeline Association
CER	Canadian Energy Regulator (formerly the National Energy Board (Canada))
CFE	Comisión Federal de Electricidad (Mexico)
CGA	Canadian Gas Association
CRE	Comisión Reguladora de Energia, or Energy Regulatory Commission (Mexico)
ECCC	Environment and Climate Change Canada
FERC	Federal Energy Regulatory Commission (U.S.)
IESO	Independent Electricity System Operator (Ontario)
NEB	National Energy Board (Canada)
NYSE	New York Stock Exchange
OBPS	Output Based Pricing System
OPEC	Organization of the Petroleum Exporting Countries
OPG	Ontario Power Generation
PHMSA	Pipeline and Hazardous Materials Safety Administration
SEC	U.S. Securities and Exchange Commission
SGER	Specified Gas Emitters Regulations (replaced by the CCIR)
TSX	Toronto Stock Exchange