FORTIS INC.

St. John's, NL - February 13, 2020

Fortis Inc. Reports 2019 Results[1]

Fortis Inc. ("Fortis" or the "Corporation") (TSX/NYSE:FTS), a leader in the North American regulated electric and gas utility industry, released its 2019 fourth-quarter and annual financial results today.

Highlights

- Strong annual net earnings of $1,655 million, or $3.79 per common share in 2019, up from $2.59 per common share in 2018
- Adjusted net earnings[2] of $1,115 million, or $2.55 per common share in 2019, up from $2.51 per common share in 2018
- Deployed capital expenditures of $3.8 billion at our utilities in 2019
- $1.2 billion common equity offering completed in the fourth quarter

"Fortis had industry leading operational results in safety and reliability which complemented our strong financial results. We also created financial flexibility by using the $1 billion proceeds from the sale of our Waneta hydroelectric generation facility and our timely $1.2 billion common equity raise late in 2019 to pay down debt," said Barry Perry, President and Chief Executive Officer, Fortis. "Going forward, our capital plan focuses on cleaner energy along with innovative, sustainable and affordable investment in our electric and gas networks."

Net Earnings

The Corporation reported net earnings attributable to common equity shareholders for 2019 of $1,655 million, or $3.79 per common share, compared to $1,100 million, or $2.59 per common share, for 2018.

The increase in annual earnings reflects: (i) a one-time after-tax gain on sale of the Waneta Expansion Hydroelectric Project ("Waneta Expansion") of $484 million, or $1.12 per common share; (ii) a one-time after-tax favourable adjustment of $83 million, or $0.19 per common share, associated with prior period impacts of a regulatory decision related to ITC's base return on common equity ("ROE"); (iii) rate base growth across the regulated utilities; and (iv) favourable foreign exchange. Growth was tempered by: (i) one-time positive tax adjustments recognized in 2018 primarily related to an election to file a consolidated state income tax return; (ii) weather with cooler temperatures in Arizona and lower rainfall in Belize; (iii) the 2019 impact of ITC's reduced base ROE; and (iv) for earnings per common share, a higher weighted average number of common shares outstanding.

For the fourth quarter of 2019, net earnings attributable to common equity shareholders were $346 million, or $0.77 per common share, compared to $261 million, or $0.61 per common share, for the same period in 2018.

The increase in quarterly earnings reflects the above noted one-time $83 million favourable adjustment related to ITC's base ROE, partially offset by a $20 million unfavourable adjustment related to the 2019 impact of ITC's reduced base ROE. The remaining change reflects rate base growth, tempered by the impact of lower rainfall in Belize and, for earnings per common share, a higher weighted average number of common shares outstanding.

Adjusted Net Earnings[2]

On an adjusted basis, net earnings attributable to common equity shareholders for 2019 were $1,115 million, or $2.55 per common share, an increase of $0.04 per common share compared to 2018.

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[1] Financial information is presented in Canadian dollars unless otherwise specified.

[2] Non-US GAAP Measures - Fortis uses financial measures that do not have a standardized meaning under generally accepted accounting principles in the United States of America ("US GAAP") and may not be comparable to similar measures presented by other entities. Fortis presents these non-US GAAP measures because management and external stakeholders use them in evaluating the Corporation's financial performance and prospects. Refer to the Non-US GAAP Reconciliation provided in this media release.

Annual adjusted earnings per common share ("EPS") increased $0.04, driven by capital investment at the regulated utilities and favourable foreign exchange, partially offset by the 2019 impact of ITC's reduced base ROE, and weather with lower-than-average rainfall in 2019 reducing hydroelectric production in Belize and cooler weather in Arizona reducing retail electricity sales at Tucson Electric Power ("TEP"). EPS also reflected a higher weighted average number of common shares outstanding.

On an adjusted basis, for the fourth quarter of 2019, net earnings attributable to common equity shareholders were $277 million, or $0.62 per common share, an increase of $0.06 per common share compared to the same period in 2018. The increase was driven by capital investment at the regulated utilities and lower operating and income tax expenses, partially offset by the 2019 impact of ITC's reduced base ROE and lower rainfall in Belize, and a higher weighted average number of common shares outstanding.

Regulatory Proceedings
In November 2019 the Federal Energy Regulatory Commission ("FERC") issued a decision on ITC's ROE complaints setting ITC's base ROE for the period of November 2013 to February 2015 and September 2016 onward at 9.88%, up to a maximum of 12.24% with incentive adders. As a result, a net favourable earnings impact of $63 million was recognized in 2019, comprised of $83 million related to the net reversal of liabilities established in prior periods, partially offset by $20 million related to the 2019 impact of a reduced base ROE. The regulated utilities in the Midcontinent Independent System Operator region, including ITC, sought rehearing of this order on the basis that it will not allow utilities to earn a reasonable rate of return on investment. In January 2020 FERC issued an order granting the rehearing for further consideration, effectively extending FERC's review.

Common Equity Offering
During the fourth quarter of 2019, the Corporation issued approximately 22.8 million common shares representing gross proceeds of $1.2 billion at a price of $52.15 per share. The issuance accelerated the equity funding needed to support the Corporation's five-year capital plan as well as strengthened the Corporation's balance sheet and credit metrics. The net proceeds were used to redeem US$500 million of outstanding 2.10% unsecured senior notes due October 4, 2021, to repay credit facility borrowings and for general corporate purposes.

Capital Expenditures
Capital expenditures in 2019 were $3.8 billion, $0.6 billion higher than in 2018, driven by higher spending at the U.S. regulated utilities.

The Corporation's five-year capital plan for 2020 through 2024 is targeted at $18.8 billion, $0.5 billion higher than the $18.3 billion capital plan reported in November 2019. The increase reflects a shift in spending that was originally planned for December 2019 but was made in January 2020 related to UNS Energy's Oso Grande Wind Project, as well as the timing of other spend that shifted to 2021.

"The Corporation continues to focus on its record of improving operational metrics like safety and reliability while, at the same time, generating strong financial performance. We are confident that the actions we are taking to progress along the path to cleaner energy and to strengthen our energy networks are prudent steps to address climate change challenges," concluded Mr. Perry.

Outlook
Over the long term, Fortis is well positioned to enhance shareholder value through the execution of its capital plan, the balance and strength of its diversified portfolio of utility businesses, and growth opportunities within and proximate to its service territories.

The Corporation's $18.8 billion five-year capital plan is expected to increase rate base from $28.0 billion in 2019 to $34.5 billion by 2022 and $38.4 billion by 2024, translating into three- and five-year compound average growth rates of 7.2% and 6.5%, respectively. The five-year capital plan reflects the continuation of key industry trends including grid modernization and the delivery of cleaner energy. Beyond the base capital plan, Fortis continues to pursue additional energy infrastructure opportunities. Key opportunities not yet included in the five-year capital plan include: further expansion of liquefied natural gas infrastructure in British Columbia; the fully permitted, cross-border, Lake Erie connector electric transmission project in Ontario; and the acceleration of cleaner energy goals in Arizona.

Fortis expects long-term growth in rate base to support continuing growth in earnings and dividends. Fortis is targeting average annual dividend growth of approximately 6% through 2024. This dividend guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at the Corporation's utilities, the successful execution of the five-year capital plan, and management's continued confidence in the strength of the Corporation's diversified portfolio of utilities and record of operational excellence.

Non-US GAAP Reconciliation

Periods ended December 31 *($ millions, except for common share data)*	**2019**	2018	Variance	**Q4 2019**	Q4 2018	Variance
Net Earnings Attributable to Common Equity Shareholders	**1,655**	1,100	555	**346**	261	85
Adjusting Items:						
Gain on disposition *(1)*	**(484)**	—	(484)	**—**	—	—
November 2019 FERC Order *(2)*	**(83)**	—	(83)	**(83)**	—	(83)
U.S. tax reform *(3)*	**12**	—	12	**12**	—	12
Unrealized loss (gain) on mark-to-market of derivatives *(4)*	**15**	10	5	**2**	(6)	8
Consolidated state income tax election *(5)*	**—**	(30)	30	**—**	—	—
Assets held for sale *(5)*	**—**	(14)	14	**—**	(14)	14
Adjusted Net Earnings Attributable to Common Equity Shareholders	**1,115**	1,066	49	**277**	241	36
Adjusted Basic Earnings per Common Share *($)*	**2.55**	2.51	0.04	**0.62**	0.56	0.06
Weighted Average Number of Common Shares Outstanding *(millions)*	**436.8**	424.7	12.1	**447.1**	427.5	19.6

(1) *Gain on sale of the Waneta Expansion, net of expenses, included in the Corporate and Other segment*
(2) *Represents the prior period impacts of the FERC order that reduced ITC's base ROE, included in the ITC segment*
(3) *The finalization of U.S. tax reform regulations associated with base-erosion and anti-abuse tax, included in the Corporate and Other segment*
(4) *Represents timing differences related to the accounting of natural gas derivatives at the Aitken Creek natural gas storage facility, included in the Energy Infrastructure segment*
(5) *Remeasurement of deferred income tax liabilities, included in the Corporate and Other segment*

Adoption of Advance Notice By-Law

The Corporation is providing notice that it has adopted Advance Notice By-Law No. 2 relating to advance notice requirements for director elections (the "By-Law"). The By-Law fixes a deadline by which shareholders must submit notice of director nominations to the Corporation prior to any annual or special meeting of shareholders at which directors are to be elected and sets out the information that a shareholder must include in a valid notice to the Corporation. The By-Law has been prepared to meet the guidelines of proxy advisory firms and the requirements of the Toronto Stock Exchange.

In the case of an annual meeting of shareholders, the By-Law requires that notice to the Corporation be given not later than the close of business on the 30th day prior to the date of the meeting. In the event that the annual meeting is to be held on a date that is less than 50 days after the first public announcement of the date of the meeting by the Corporation, notice may be made not later than the close of business on the 10th day following such public announcement.

In the case of a special meeting of shareholders (which is not also an annual meeting of shareholders) called for the purpose of electing directors (whether or not called for other purposes), notice to the Corporation must be given not later than the close of business on the 15th day following the first public announcement of the date of the meeting by the Corporation.

If the Corporation uses the notice-and-access provisions of National Instrument 54-101 - *Communication with Beneficial Owners of Securities of a Reporting Issuer* for delivery of proxy related materials, notice to the Corporation must be given not later than the close of business on the 40th day prior to the date of the meeting. In the event that the meeting is to be held on a date that is less than 50 days after the first public announcement of the date of the meeting by the Corporation, notice must be given not later than the 10th day (in the case of an annual meeting) or 15th day (in the case of a special meeting) following such public announcement.

The By-Law will be placed before shareholders for ratification and confirmation at the upcoming annual and special meeting of shareholders. If shareholders do not approve the resolution ratifying and confirming the adoption of the By-Law, the By-Law will terminate and be of no further force or effect. A copy of the By-Law is available on www.sedar.com and on the Corporation's website, www.fortisinc.com. As well, a copy and summary of the By-Law will be included in the management information circular of the Corporation prepared in connection with the meeting.

About Fortis

Fortis is a leader in the North American regulated electric and gas utility industry with 2019 revenue of $8.8 billion and total assets of $53 billion as at December 31, 2019. The Corporation's 9,000 employees serve utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries.

Forward-Looking Information

Fortis includes forward-looking information in this media release within the meaning of applicable Canadian securities laws and forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 (collectively referred to as "forward-looking information"). Forward-looking information reflects expectations of Fortis management regarding future growth, results of operations, performance, business prospects and opportunities. Wherever possible, words such as anticipates, believes, budgets, could, estimates, expects, forecasts, intends, may, might, plans, projects, schedule, should, target, will, would and the negative of these terms and other similar terminology or expressions have been used to identify the forward-looking information, which includes, without limitation: the Corporation's forecast capital spending for the five-year period from 2020 through 2024; the Corporation's forecast rate base for 2022 and 2024; the expectation that long-term sustainable growth in rate base will support continuing growth in earnings and dividends; and targeted average annual dividend growth through 2024.

Forward-looking information involves significant risk, uncertainties and assumptions. Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information. These factors or assumptions are subject to inherent risks and uncertainties surrounding future expectations generally, including those identified from time to time in the forward-looking information. Such risk factors or assumptions include, but are not limited to: reasonable decisions by utility regulators and the expectation of regulatory stability; the implementation of the Corporation's five-year capital plan; no material capital project and financing cost overrun related to any of the Corporation's capital projects; sufficient human resources to deliver service and execute the capital plan; the realization of additional opportunities; the impact of fluctuations in foreign exchange; and the Board exercising its discretion to declare dividends, taking into account the business performance and financial condition of the Corporation. Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking information. These factors should be considered carefully and undue reliance should not be placed on the forward-looking information. For additional information with respect to certain of these risks or factors, reference should be made to the continuous disclosure materials filed from time to time by the Corporation with Canadian securities regulatory authorities and the Securities and Exchange Commission. All forward-looking information included in this media release is given as of the date of this media release and Fortis disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

Teleconference to Discuss 2019 Annual Results

A teleconference and webcast will be held on February 13 at 8:30 a.m. (Eastern). Barry Perry, President and Chief Executive Officer and Jocelyn Perry, Executive Vice President, Chief Financial Officer, will discuss the Corporation's 2019 annual results.

Analysts, members of the media and other interested parties in North America are invited to participate by calling 877.223.4471. International participants may participate by calling 647.788.4922. Please dial in 10 minutes prior to the start of the call. No pass code is required.

A live and archived audio webcast of the teleconference will be available on the Corporation's website, www.fortisinc.com.

A replay of the conference will be available two hours after the conclusion of the call until March 13, 2020. Please call 1.800.585.8367 or 416.621.4642 and enter pass code 3581627.

Additional Information

This media release should be read in conjunction with the Corporation's Management Discussion and Analysis and Consolidated Financial Statements. This and additional information can be accessed at www.fortisinc.com, www.sedar.com, or www.sec.gov.

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Management Discussion and Analysis

For the year ended December 31, 2019
Dated February 12, 2020

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This MD&A has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. It should be read in conjunction with the 2019 Annual Financial Statements and is subject to the cautionary statement and disclaimer provided under "Forward-Looking Information" on page 45. Further information about Fortis, including its Annual Information Form filed on SEDAR, can be accessed at www.fortisinc.com, www.sedar.com, or www.sec.gov.

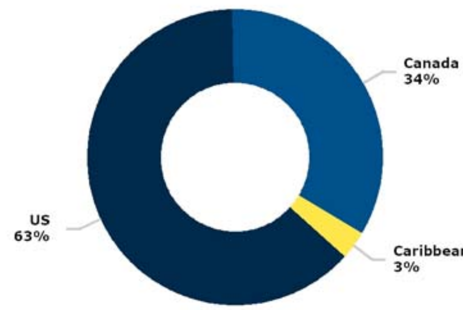
Financial information herein has been prepared in accordance with US GAAP (except for indicated Non-US GAAP Financial Measures) and, unless otherwise specified, is presented in Canadian dollars based, as applicable, on the following US-to-Canadian dollar exchange rates: (i) average of 1.33 and 1.30 for the years ended December 31, 2019 and 2018, respectively; (ii) 1.30 and 1.36 as at December 31, 2019 and 2018, respectively; and (iii) 1.32 for all forecast periods. Certain terms used in this MD&A are defined in the "Glossary" on page 46.

ABOUT FORTIS

Fortis (TSX/NYSE: FTS) is a well-diversified leader in the North American regulated electric and gas utility industry, with revenue of $8.8 billion and total assets of $53 billion as at December 31, 2019.

Regulated utilities account for 99% of the Corporation's assets with the remainder primarily attributable to non-regulated energy infrastructure. The Corporation's 9,000 employees serve 3.3 million utility customers in five Canadian provinces, nine US states and three Caribbean countries. As at December 31, 2019, 66% of the Corporation's assets were located outside Canada and 60% of 2019 revenue was derived from foreign operations.

Total Assets at December 31, 2019



Fortis is principally an energy delivery company, with 93% of its assets related to transmission and distribution. The business is characterized by low-risk, stable and predictable earnings and cash flows. EPS and TSR are the primary measures of financial performance.

Fortis' regulated utility businesses are: ITC (electric transmission - Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma); UNS Energy (integrated electric and natural gas distribution - Arizona); Central Hudson (electric transmission and distribution, and natural gas distribution - New York); FortisBC Energy (natural gas transmission and distribution - British Columbia); FortisAlberta (electric distribution - Alberta); FortisBC Electric (integrated electric - British Columbia); Newfoundland Power (integrated electric - Newfoundland and Labrador); Maritime Electric (integrated electric - Prince Edward Island); FortisOntario (integrated electric - Ontario); Caribbean Utilities (integrated electric - Grand Cayman); and FortisTCI (integrated electric - Turks and Caicos Islands). Fortis also holds equity investments in the Wataynikaneyap Partnership (electric transmission - Ontario) and Belize Electricity (integrated electric - Belize).

Non-regulated energy infrastructure is comprised of Aitken Creek (natural gas storage facility - British Columbia), BECOL (three hydroelectric generation facilities - Belize) and the Waneta Expansion up to its disposition in April 2019 (see "Significant Items" on page 3).

Fortis has a unique operating model with a small head office in St. John's, Newfoundland and Labrador and business units that operate on a substantially autonomous basis. Each utility has its own management team and most have a board of directors with a majority of independent members, which provides effective oversight within the broad parameters of Fortis policies and best practices. Subsidiary autonomy supports constructive relationships with regulators, policy makers, customers and communities. Fortis believes this model enhances accountability, opportunity and performance across the Corporation's businesses, and positions Fortis well for future investment opportunities.

Fortis strives to provide safe, reliable and cost-effective energy service to customers using sustainable practices while delivering long-term profitable growth to shareholders. Management is focused on achieving growth through the execution of the consolidated capital plan and the pursuit of additional investment opportunities within and proximate to existing service territories (see "Capital Plan" on page 21).

Additional information about the Corporation's business and reporting units is provided in Note 1 in the 2019 Annual Financial Statements.

SIGNIFICANT ITEMS

Disposition
On April 16, 2019, Fortis sold its 51% ownership interest in the 335-MW Waneta Expansion for proceeds of $995 million. A gain on disposition of $577 million ($484 million after tax), net of expenses, was recognized in the Corporate and Other segment.

Fortis used the net proceeds to repay credit facility borrowings and repurchase, via a tender offer, US$400 million of its outstanding 3.055% unsecured senior notes due in 2026. The reduced earnings from the Waneta Expansion were offset by lower finance charges and a gain on repayment of the 3.055% notes.

Common Equity Offering
In the fourth quarter of 2019, the Corporation issued approximately 22.8 million common shares at a price of $52.15 per share for gross proceeds of $1,190 million ($1,167 million net of commissions). The net proceeds were used to redeem US$500 million of its outstanding 2.10% unsecured senior notes due October 4, 2021, to repay credit facility borrowings and for general corporate purposes.

November 2019 FERC Order
In November 2019 FERC issued an order reducing the base ROE for ITC's MISO Subsidiaries to 9.88%, up to a maximum of 12.24% with incentive adders. Including incentive adders, this implies an all-in ROE for ITC's MISO subsidiaries of 10.63% compared to the previous all-in ROE of 11.07%. The net impact was a $63 million increase in earnings, comprised of $83 million related to the net reversal of liabilities established in prior periods, partially offset by $20 million related to the 2019 impact of the reduced ROE. See "Regulatory Highlights" on page 13 for further information.

PERFORMANCE AT A GLANCE

Key Financial Metrics *($ millions, except as indicated)*	**2019**	2018	Variance
Common Equity Earnings			
Actual	**1,655**	1,100	555
Adjusted [(1)]	**1,115**	1,066	49
Basic EPS *($)*			
Actual	**3.79**	2.59	1.20
Adjusted [(1)]	**2.55**	2.51	0.04
Dividends			
Paid per Common Share *($)*	**1.8275**	1.7250	0.1025
Actual Payout Ratio *(%)*	**48.2**	66.6	(18.4)
Adjusted Payout Ratio [(1)] *(%)*	**71.7**	68.7	3.0
Weighted Average Number of Common Shares Outstanding *(millions)*	**436.8**	424.7	12.1
Operating Cash Flow	**2,663**	2,604	59
Capital Expenditures	**3,818**	3,218	600

[(1)] *See "Non-US GAAP Financial Measures" on page 12*

TSR [(1)] *(%)*	1-Year	5-Year	10-Year	20-Year
Fortis	22.7%	10.8%	10.6%	14.3%

[(1)] *Total annualized shareholder return per Bloomberg, as at December 31, 2019*

Earnings and EPS
The $555 million increase in Common Equity Earnings reflects significant one-time items, Rate Base growth driven by the Corporation's capital plan at the regulated utilities and favourable foreign exchange, partially offset by the impact of weather in Belize and Arizona, regulatory decisions at ITC and one-time positive tax adjustments primarily recognized in 2018.

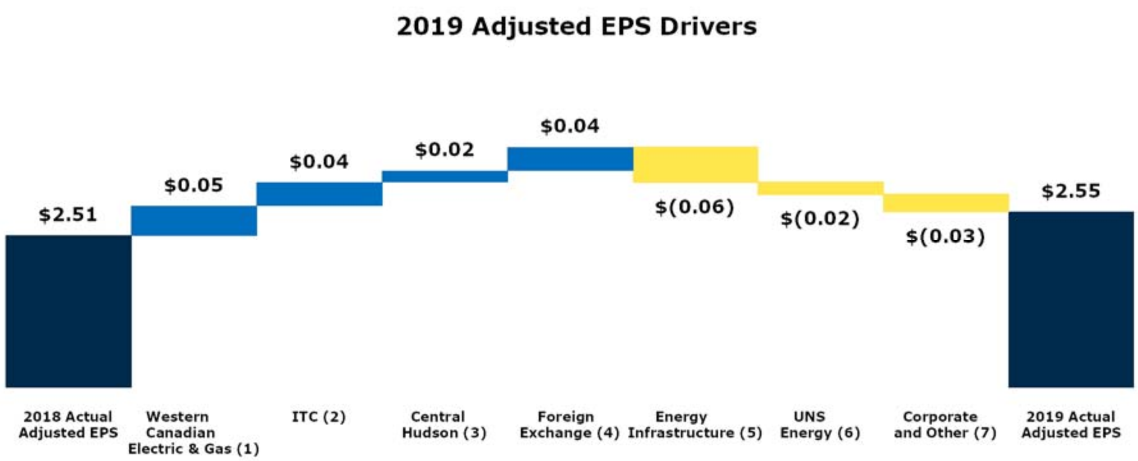
The significant one-time items were a $484 million gain on the disposition of the Waneta Expansion and an $83 million favourable adjustment resulting from the November 2019 FERC Order (see "Regulatory Highlights" on page 13), which resulted in the 2019 net reversal of liabilities established in prior years.

The regulated utilities delivered positive financial results reflecting Rate Base growth, driven by ITC, lower operating expenses, primarily at FortisAlberta, and favourable foreign exchange. This growth was tempered by: (i) a lower ROE at ITC due to the November 2019 FERC Order and lower ROE incentive adders effective April 2018; (ii) lower earnings contribution from UNS Energy due to lower retail sales, driven by cooler weather, and higher costs associated with Rate Base growth not yet reflected in rates; and (iii) lower earnings contribution from the Energy Infrastructure segment due to lower hydroelectric production in Belize and lower realized margins at Aitken Creek.

The one-time positive tax adjustments recognized in 2018 related to an election to file a consolidated state tax return and the designation of net assets related to the Waneta Expansion as held for sale totalling $30 million and $14 million, respectively. In addition, the finalization of US tax reform regulations associated with base-erosion and anti-abuse tax resulted in the recognition of income tax expense of $12 million in 2019.

Finally, a 12.1 million increase in the weighted average number of common shares outstanding associated with the Corporation's (i) $1.2 billion common equity issuance in the fourth quarter of 2019 (see "Significant Items" on page 3), (ii) ATM Program, and (iii) DRIP and share purchase plan, resulted in a $0.07 decrease in basic EPS.

Adjusted Common Equity Earnings and Adjusted Basic EPS increased by $49 million and $0.04, respectively. Refer to "Non-US GAAP Financial Measures" on page 12 for a reconciliation of these measures. The change in Adjusted Basic EPS is illustrated in the chart below.



(1) Includes FortisBC Energy, FortisBC Electric and FortisAlberta. Driven primarily by Rate Base growth and lower operating expenses
(2) Driven by Rate Base growth, partially offset by a lower 2019 ROE due to the November 2019 FERC Order
(3) Driven by Rate Base growth
(4) Average FX of $1.33 for 2019 compared to $1.30 for 2018
(5) Driven primarily by reduced hydroelectric production at Belize due to lower rainfall
(6) Driven primarily by higher costs associated with Rate Base growth not yet reflected in customer rates and lower retail sales due mainly to unfavourable weather
(7) Weighted average shares of 436.8 million in 2019 compared to 424.7 million in 2018, partially offset by favourable foreign exchange contracts and higher income tax recoveries

Dividends and TSR

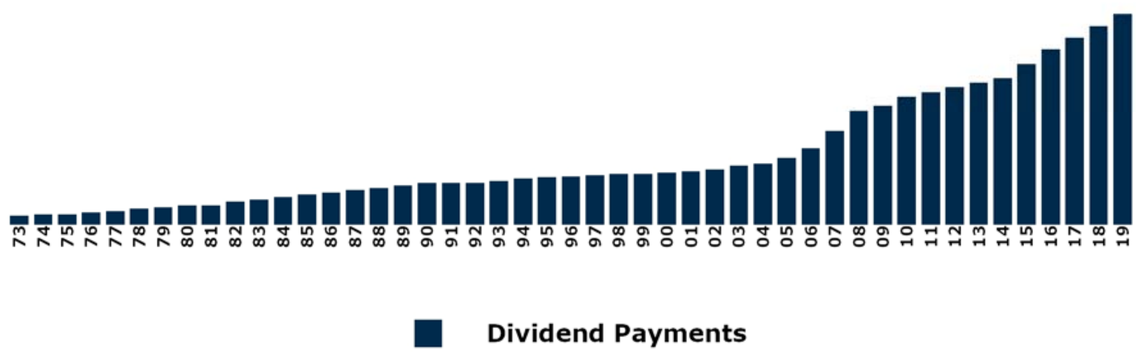
Fortis paid a dividend of $0.4775 per common share in the fourth quarter of 2019, up from $0.45 paid in each of the previous four quarters.

The total 2019 dividend paid per common share was $1.8275, up $0.1025 or nearly 6.0% from 2018 and in line with the Corporation's dividend guidance. The Actual Payout Ratio was 48.2% in 2019 compared to 66.6% in 2018 and an annual average of 61.4% over the five-year period of 2015 through 2019. The decrease in the 2019 Actual Payout Ratio was driven by the gain on disposition of the Waneta Expansion (see "Significant Items" on page 3).

Fortis has increased its common share dividend for 46 consecutive years. Growth of dividends and the market price of the Corporation's common shares have together yielded a 1-year, 5-year, 10-year and 20-year TSR of 22.7%, 10.8%, 10.6% and 14.3%, respectively.

In September 2019 Fortis extended its targeted average annual dividend per common share growth of approximately 6% through 2024.

46 Years of Common Share Dividend Increases



Operating Cash Flow

The $59 million increase was due to higher cash earnings, driven by Rate Base growth at the regulated utilities, led by ITC. The increase was partially offset by: (i) unfavourable changes due to the normal operation of long-term regulatory deferrals at ITC; (ii) unfavourable changes in working capital, due primarily to timing differences, partially offset by income tax refunds received in 2019; and (iii) lower cash earnings from the Energy Infrastructure segment (see "Business Unit Performance - Energy Infrastructure" on page 11).

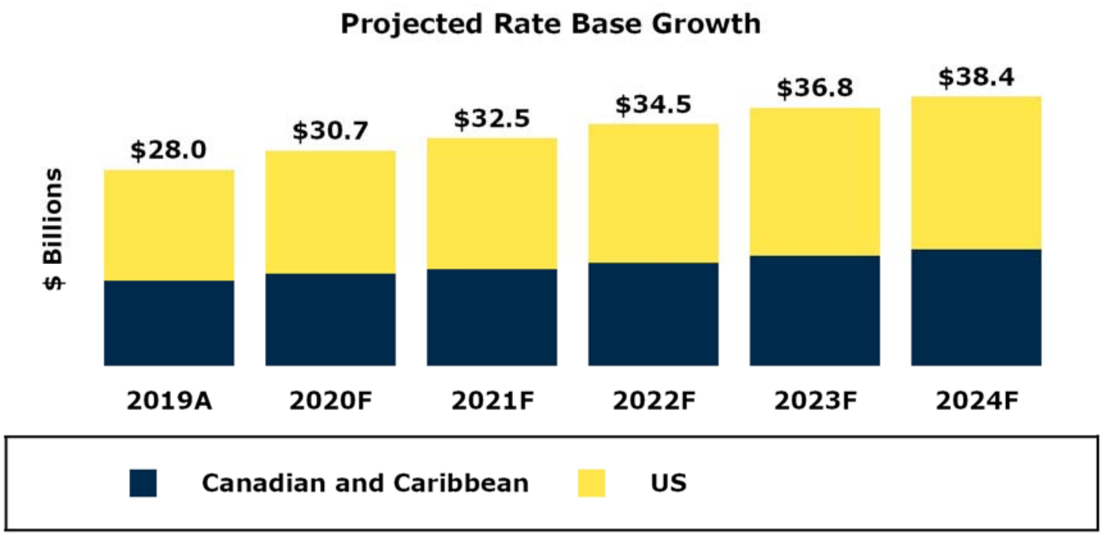
Capital Expenditures

Capital expenditures in 2019 were $3.8 billion, $0.6 billion higher than in 2018 and $0.5 billion lower than forecast in the Q3 2019 MD&A. The $0.6 billion increase over the prior year was driven by higher spending at the US regulated utilities. The $0.5 billion decrease from forecast was due to: (i) a $0.3 billion delayed payment related to the construction of the Oso Grande Wind Project as the performance obligations were not fulfilled until January 2020; (ii) a revised forecast and timeline related to the Southline Transmission Project resulting in $0.1 billion being deferred until 2021; and (iii) revisions to various smaller projects resulting in $0.1 billion being deferred until 2021. See "Capital Plan" on page 21 for further information.

The Corporation's five-year 2020-2024 capital plan is targeted at $18.8 billion, approximately $0.5 billion higher than the $18.3 billion capital plan disclosed in the Q3 2019 MD&A. The increase reflects the shift in spending that was originally planned for December 2019 but was made in January 2020 related to UNS Energy's Oso Grande Wind Project, as well as the timing of other spend that shifted to 2021.

Funding of the capital plan is expected to be primarily through Operating Cash Flow, utility debt and common equity from the Corporation's DRIP.

The five-year capital plan is expected to increase midyear Rate Base from $28.0 billion in 2019 to $34.5 billion by 2022 and $38.4 billion by 2024, representing three- and five-year CAGRs of 7.2% and 6.5%, respectively. These CAGRs are supportive of continuing growth in earnings and dividends.



Beyond the base capital plan, Fortis continues to pursue additional energy infrastructure opportunities. Key opportunities not yet included in the five-year capital plan include: further expansion of liquefied natural gas infrastructure in British Columbia; the fully permitted, cross-border, Lake Erie connector electric transmission project in Ontario; and the acceleration of cleaner energy goals in Arizona.

THE INDUSTRY

The North American energy industry continues to transform. There is a heightened focus on the impacts of climate change and the need for cleaner energy and energy conservation initiatives to preserve the environment for future generations. The effects of climate change, coupled with technological advancements, have rapidly shifted customer expectations for cleaner energy. The trend toward renewables and natural gas as a key part of the energy mix, as well as the increasing affordability of cleaner energy, is driving opportunity in the utility sector.

Changing energy policies at the federal, state and provincial levels are creating volatility in certain jurisdictions by introducing uncertainty around environmental, tax and trade regulation. The regulatory and compliance operating environment is also evolving and becoming increasingly complex. These changes are creating additional opportunities to expand investment in new generation sources, including natural gas, solar and wind, as well as infrastructure to interconnect renewable energy sources to the grid. Investment opportunities in storage are also growing with the proliferation of variable renewable generation sources and decreasing costs of storage technology. The Corporation's utilities are well positioned and actively involved in pursuing these opportunities.

New technology is driving change across all service territories. Energy delivery systems are being upgraded with advanced meters, improved controls and more capable operational technology, providing utilities with detailed usage data. Energy management capabilities are expanding through emerging storage and demand response systems, and customers have been enabled with options to manage and reduce energy usage and access more affordable distributed generation technology.

While some of these new technologies challenge the traditional role of utilities as one-way service providers, they also offer strategic investment opportunities for improving and expanding service. The proliferation of information and operational technology, along with the exponential growth in data and grid interconnections, is driving the need for increased cyber and physical security systems.

Meaningful customer engagement is increasingly important for utilities as customer expectations change and competition for customer attention becomes more intense. Customers want to make informed energy choices and become active participants in the delivery of their energy services. They also expect personalized service, customized service offerings and more real-time, digital communication.

Fortis is well positioned to capitalize on evolving industry opportunities. Its decentralized structure and customer-focused business culture support the efforts required to meet changing customer expectations and to work with policy makers and regulators on energy and service solutions that are financially sustainable. Fortis is also a strategic partner in the Energy Impact Partners utility coalition, which is a strategic private entity fund that invests in emerging technologies, products, services and business models across the full electricity supply chain.

By leveraging these strengths and partnerships, Fortis expects to remain at the forefront of this ever-changing industry.

OPERATING RESULTS

			Variance	
($ millions)	**2019**	2018	FX	Other
Revenue	**8,783**	8,390	113	280
Energy Supply Costs	**2,520**	2,495	30	(5)
Operating Expenses	**2,452**	2,287	34	131
Depreciation and Amortization	**1,350**	1,243	14	93
Gain on Disposition	**577**	—	—	577
Other Income, Net	**138**	60	1	77
Finance Charges	**1,035**	974	10	51
Income Tax Expense	**289**	165	4	120
Net Earnings	**1,852**	1,286	22	544
Net Earnings Attributable to:				
Non-Controlling Interests	**130**	120	2	8
Preference Equity Shareholders	**67**	66	—	1
Common Equity Shareholders	**1,655**	1,100	20	535
Net Earnings	**1,852**	1,286	22	544

Revenue
The increase was due primarily to: (i) Rate Base growth at the regulated utilities, led by ITC; (ii) overall higher flow-through costs in customer rates; (iii) favourable foreign exchange of $113 million; and (iv) a $91 million favourable adjustment associated with the November 2019 FERC Order (see "Regulatory Highlights" on page 13). The increase was partially offset by: (i) lower revenue contribution from the Energy Infrastructure segment due primarily to the disposition of the Waneta Expansion and reduced hydroelectric production in Belize due to lower rainfall; and (ii) lower retail sales at UNS Energy due to weather.

Energy Supply Costs
Energy supply costs were comparable to 2018. A reclassification of finance lease costs of $29 million from energy supply costs to finance charges, due to the adoption of a new lease standard (see "Accounting Matters - New Accounting Policies" on page 33), was offset by overall higher commodity costs.

Operating Expenses
The increase was due primarily to general inflationary and employee-related cost increases, including higher stock-based compensation costs driven by an increase in the Corporation's share price and overall performance.

Depreciation and Amortization
The increase was due primarily to continued investment in energy infrastructure at the Corporation's regulated utilities.

Gain on Disposition
See "Significant Items" on page 3.

Other Income, Net

The increase was due primarily to: (i) favourable foreign exchange contracts; (ii) higher AFUDC equity earnings at UNS Energy; and (iii) an $11 million gain on the repayment of US$400 million of debt via tender offer (see "Significant Items" on page 3).

Finance Charges

The increase was due primarily to: (i) overall higher operating utility debt levels to support the capital plan; and (ii) the reclassification of finance lease interest of $29 million to finance charges from energy supply costs. The increase was partially offset by: (i) lower finance charges due to the repayment of debt (see "Significant Items" on page 3); and (ii) the reversal of interest of $16 million as a result of the November 2019 FERC Order (see "Regulatory Highlights" on page 13).

Income Tax Expense

The increase was driven by: (i) tax on the disposition of the Waneta Expansion (see "Significant Items" on page 3); (ii) $44 million of favourable deferred income tax liability remeasurements in 2018 arising from an election to file a consolidated state income tax return and the designation of net assets related to the Waneta Expansion as held for sale; and (iii) the recognition of income tax expense of $12 million in 2019 related to the finalization of US tax reform regulations associated with base-erosion and anti-abuse tax, partially offset by higher valuation allowances released in 2019 compared to 2018.

Net Earnings

See "Performance at a Glance - Earnings and EPS" on page 3.

BUSINESS UNIT PERFORMANCE

Common Equity Earnings				
Years Ended December 31			Variance	
($ millions)	**2019**	2018	FX [1]	Other
Regulated Utilities				
ITC	**471**	361	9	101
UNS Energy	**292**	293	6	(7)
Central Hudson	**85**	74	2	9
FortisBC Energy	**165**	155	—	10
FortisAlberta	**131**	120	—	11
FortisBC Electric	**54**	56	—	(2)
Other Electric [2]	**106**	105	1	—
	1,304	1,164	18	122
Non-Regulated				
Energy Infrastructure	**18**	72	1	(55)
Corporate and Other	**333**	(136)	1	468
Common Equity Earnings	**1,655**	1,100	20	535

(1) *The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI and BECOL is the US dollar. The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the US dollar at BZ$2.00=US$1.00. The Corporate and Other segment includes certain transactions denominated in US dollars.*

(2) *Comprised of the utility operations in eastern Canada and the Caribbean: Newfoundland Power; Maritime Electric; FortisOntario; Caribbean Utilities; FortisTCI; and Belize Electricity.*

ITC			Variance	
($ millions)	**2019**	2018	FX	Other
Revenue [1]	**1,761**	1,504	35	222
Earnings [1]	**471**	361	9	101

(1) *Revenue represents 100% of ITC. Earnings represent the Corporation's 80.1% controlling ownership interest in ITC and reflect consolidated purchase price accounting adjustments.*

Revenue
The increase, net of foreign exchange, was due primarily to a $91 million favourable adjustment to revenue associated with the November 2019 FERC Order (see "Regulatory Highlights" on page 13). Higher flow-through costs in customer rates and growth in Rate Base also contributed to the increase in revenue, partially offset by a reduction in the ROE incentive adders.

Earnings
The increase, net of foreign exchange, was due primarily to the November 2019 FERC Order that resulted in a $63 million increase in earnings, comprised of $83 million related to the net reversal of liabilities established in prior periods, partially offset by $20 million related to the 2019 impact of the reduced ROE. Growth in Rate Base, lower business development costs and a lower effective tax rate also contributed to the earnings increase, partially offset by a reduction in the ROE incentive adders and higher non-recoverable expenses.

UNS Energy			Variance	
	2019	2018	FX	Other
Retail electricity sales *(GWh)*	**10,431**	10,600	—	(169)
Wholesale electricity sales *(GWh)* [(1)]	**7,923**	6,806	—	1,117
Gas sales *(PJ)*	**16**	13	—	3
Revenue *($ millions)*	**2,212**	2,202	46	(36)
Earnings *($ millions)*	**292**	293	6	(7)

(1) *Primarily short-term wholesale sales*

Sales
The decrease in retail electricity sales was due to reduced air conditioning load as a result of cooler-than-normal temperatures in the spring and summer months compared to warmer-than-normal temperatures for the same periods in 2018.

The increase in wholesale electricity sales was due primarily to higher short-term wholesale sales reflecting an increase in system capacity related to Gila River Unit 2. Revenue from short-term wholesale sales is primarily returned to customers through regulatory deferral mechanisms and, therefore, does not materially impact earnings.

The increase in gas volumes was due primarily to heating load as a result of cooler temperatures in the winter months.

Revenue
The decrease, net of foreign exchange, was due primarily to the flow through of lower energy supply costs and lower retail sales. The decrease in revenue was partially offset by higher flow-through costs related to Springerville Units 3 and 4 and higher short-term wholesale sales.

Earnings
The decrease, net of foreign exchange, was due primarily to higher depreciation and interest expense associated with Rate Base growth not yet reflected in customer rates, and lower retail sales. The decrease was partially offset by higher AFUDC earnings, lower operating costs associated with scheduled outages and maintenance, and a lower effective tax rate.

Central Hudson			Variance	
	2019	2018	FX	Other
Electricity sales *(GWh)*	**4,963**	5,118	—	(155)
Gas sales *(PJ)*	**22**	24	—	(2)
Revenue *($ millions)*	**917**	924	24	(31)
Earnings *($ millions)*	**85**	74	2	9

Sales
The decrease in electricity sales was due primarily to lower average consumption as a result of warmer temperatures in winter months that decreased heating load and cooler temperatures in summer months that decreased air conditioning load. Gas volumes were comparable to 2018.

Changes in electricity sales and gas volumes at Central Hudson are subject to regulatory revenue decoupling mechanisms and, therefore, do not materially impact earnings.

Revenue
The decrease, net of foreign exchange, was due primarily to the flow through of lower energy supply costs and lower electricity sales, partially offset by Rate Base growth.

Earnings
The increase, net of foreign exchange, was primarily due to Rate Base growth and higher storm restoration costs in 2018.

FortisBC Energy	**2019**	2018	Variance
Gas sales *(PJ)*	**227**	212	15
Revenue *($ millions)*	**1,331**	1,187	144
Earnings *($ millions)*	**165**	155	10

Sales
The increase was due primarily to higher average residential and commercial consumption as a result of colder temperatures in 2019 that increased heating load and higher consumption by transportation customers.

Revenue
The increase was due primarily to a higher cost of natural gas and other flow-through costs recovered from customers, the recovery of gas storage and transportation costs related to a third-party pipeline incident that occurred in the fourth quarter of 2018, and Rate Base growth.

Earnings
The increase was due primarily to Rate Base growth.

FortisBC Energy earns approximately the same margin regardless of whether a customer contracts for the purchase and delivery of natural gas or only for the delivery. Due to regulatory deferral mechanisms, changes in consumption levels and commodity costs do not materially impact earnings.

FortisAlberta	**2019**	2018	Variance
Energy deliveries *(GWh)*	**16,887**	17,154	(267)
Revenue *($ millions)*	**598**	579	19
Earnings *($ millions)*	**131**	120	11

Deliveries
The decrease was due primarily to lower average consumption by oil and gas customers along with lower average residential consumption as a result of cooler temperatures in 2019 that decreased air conditioning load in the summer months. The decrease in energy deliveries was partially offset by higher average commercial consumption due to customer additions.

As more than 80% of FortisAlberta's revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

Revenue
The increase was due primarily to Rate Base growth and customer additions, partially offset by a favourable capital tracker revenue true-up in 2018 related to capital expenditures in 2016 and 2017.

Earnings
The increase was due primarily to lower operating expenses, driven by reduced labour costs, and Rate Base growth. The increase was partially offset by the 2018 capital tracker revenue true-up and a higher effective tax rate.

FortisBC Electric	**2019**	2018	Variance
Electricity sales *(GWh)*	**3,326**	3,250	76
Revenue *($ millions)*	**418**	408	10
Earnings *($ millions)*	**54**	56	(2)

Sales
The increase was due primarily to higher consumption by industrial customers.

Revenue
The increase was due primarily to higher electricity sales, higher revenue related to a customer load growth regulatory mechanism and overall higher flow-through costs. The increase was partially offset by lower surplus power sales and the loss of revenue associated with the provision of operating, maintenance and management services to the Waneta Expansion (see "Significant Items" on page 3).

Earnings
The decrease was due primarily to the loss of revenue associated with the Waneta Expansion, partially offset by Rate Base growth.

Other Electric			Variance	
	2019	2018	FX	Other
Electricity sales *(GWh)*	**9,366**	9,314	—	52
Revenue *($ millions)*	**1,467**	1,412	7	48
Earnings *($ millions)*	**106**	105	1	—

Sales
The increase was due primarily to overall higher average consumption in the Caribbean and customer additions.

Revenue
The increase, net of foreign exchange, was due primarily to the flow through of higher energy supply costs and higher electricity sales, partially offset by business interruption insurance proceeds recognized in 2018 at FortisTCI related to Hurricane Irma.

Earnings
Earnings, net of foreign exchange, were comparable to 2018. Higher electricity sales and Rate Base growth were offset by FortisTCI's insurance proceeds recognized in 2018.

Energy Infrastructure			Variance	
	2019	2018	FX	Other
Electricity sales *(GWh)*	**144**	853	—	(709)
Revenue *($ millions)*	**82**	184	1	(103)
Earnings *($ millions)*	**18**	72	1	(55)

Sales
Electricity sales decreased by 541 GWh due to the disposition of the Waneta Expansion (see "Significant Items" on page 3), with the remaining decrease due to lower hydroelectric production in Belize reflecting lower rainfall.

Revenue and Earnings
The decreases in revenue and earnings reflected: (i) lower hydroelectric production in Belize; (ii) the disposition of the Waneta Expansion; (iii) lower realized margins at Aitken Creek; and (iv) the unfavourable impact of mark-to-market accounting of natural gas derivatives at Aitken Creek, with unrealized losses of $15 million during 2019 compared to $10 million during 2018.

Aitken Creek is subject to commodity price risk, as it purchases and holds natural gas in storage to earn a profit margin from its ultimate sale. Aitken Creek mitigates this risk by using derivatives to materially lock in the profit margin that will be realized upon the sale of natural gas. The fair value accounting of these derivatives creates timing differences and the resulting earnings volatility can be significant.

Corporate and Other			Variance	
($ millions)	**2019**	2018	FX	Other
Net income (expenses)	**333**	(136)	1	468

The increase in net income was driven by: (i) a net after-tax gain of $484 million on the disposition of the Waneta Expansion (see "Significant Items" on page 3); (ii) lower finance charges associated with the disposition, along with a gain on the repayment of debt; (iii) favourable changes associated with foreign exchange contracts in 2019 compared to 2018; and (iv) lower tax expense due to higher valuation allowances released in 2019 compared to 2018, partially offset by the recognition of base-erosion and anti-abuse tax in 2019 as a result of the finalization of the related US tax reform regulations. The increase was also partially offset by lower income tax recovery due to the remeasurement of deferred tax liabilities recognized during 2018: (i) $30 million resulting from the election to file a consolidated state income tax return; and (ii) $14 million associated with the designation of the net assets of the Waneta Expansion as held for sale.

NON-US GAAP FINANCIAL MEASURES

Adjusted Common Equity Earnings, Adjusted Basic EPS and Adjusted Payout Ratio are Non-US GAAP Financial Measures and may not be comparable with similar measures used by other entities. They are presented because management and external stakeholders use them in evaluating the Corporation's financial performance and prospects.

Net earnings attributable to common equity shareholders (i.e., Common Equity Earnings) and basic EPS are the most directly comparable US GAAP measures to Adjusted Common Equity Earnings and Adjusted Basic EPS, respectively. The Actual Payout Ratio calculated using Common Equity Earnings is the most comparable US GAAP measure to the Adjusted Payout Ratio.

Adjusted Common Equity Earnings and Adjusted Basic EPS reflect items that management excludes in its key decision-making processes and evaluation of operating results, and are reconciled as follows.

Non-US GAAP Reconciliation Years Ended December 31 *($ millions, except as shown)*	**2019**	2018	Variance
Common Equity Earnings	**1,655**	1,100	555
Adjusting items:			
Gain on disposition [1]	**(484)**	—	(484)
November 2019 FERC Order (2)	**(83)**	—	(83)
US tax reform (3)	**12**	—	12
Unrealized loss on mark-to-market of derivatives (4)	**15**	10	5
Consolidated state income tax election (5)	**—**	(30)	30
Assets held for sale (5)	**—**	(14)	14
Adjusted Common Equity Earnings	**1,115**	1,066	49
Adjusted Basic EPS *($)*	**2.55**	2.51	0.04

(1) *See "Significant Items" on page 3, included in the Corporate and Other segment*
(2) *See "Regulatory Highlights" below, included in the ITC segment*
(3) *The finalization of US tax reform regulations associated with base-erosion and anti-abuse tax, included in the Corporate and Other segment*
(4) *Represents timing differences related to the accounting of natural gas derivatives at Aitken Creek, included in the Energy Infrastructure segment*
(5) *Remeasurement of deferred income tax liabilities, included in the Corporate and Other segment*

REGULATORY HIGHLIGHTS

Regulation

The earnings of the Corporation's regulated utilities are determined under COS Regulation, with some using PBR mechanisms.

Under COS Regulation, the regulator sets customer rates to permit a reasonable opportunity for the timely recovery of the estimated costs of providing service, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved Rate Base. Under PBR mechanisms, formulae are generally applied that incorporate inflation and assumed productivity improvements for a set term.

The ability to recover prudently incurred costs of providing service and earn the regulator-approved ROE or ROA generally depends on achieving the forecasts established in the rate-setting process. There can be varying degrees of regulatory lag between when costs are incurred and when they are reflected in customer rates.

Transmission operations in the US are regulated federally by FERC. Remaining utility operations in the US and Canada are regulated by state or provincial regulators. Utility operations in the Caribbean are regulated by government authorities.

Additional information about regulation and the regulatory matters discussed below is provided in Note 2 in the 2019 Annual Financial Statements. Also refer to "Business Risks - Regulation" on page 25.

ITC

Incentive Adder Complaint

In April 2018 a third-party complaint was filed with FERC challenging the independence incentive adders that are included in transmission rates charged by ITC's MISO Subsidiaries. The adder allowed up to 0.50% or 1.00% to be added to the authorized ROE, subject to any ROE cap established by FERC. In October 2018 FERC issued an order reducing the adders to 0.25%, effective April 20, 2018. This equated to a 0.25% decrease in ROE, down from the approximate 0.50% that ITC was earning in rates previously approved by FERC. ITC began reflecting the 0.25% adder in transmission rates in November 2018. ITC's MISO Subsidiaries sought rehearing of this order in 2018, which was denied by FERC. In September 2019 ITC's MISO Subsidiaries filed an appeal in the US Court of Appeal. The final resolution of this matter is not expected to have a material impact on the Corporation's earnings or cash flows.

ROE Complaints
Two third-party complaints requested that the base ROE for MISO transmission owners, including ITC's MISO Subsidiaries, be found to no longer be just or reasonable. The complaints cover two consecutive 15-month periods from November 2013 through February 2015 (the "Initial Refund Period" or "Initial Complaint") and February 2015 through May 2016 (the "Second Refund Period" or "Second Complaint").

In June 2016 the presiding ALJ issued an initial decision on the Second Complaint, recommending a base ROE of 9.70%, up to a maximum of 10.68% with incentive adders. Pending an order from FERC, an estimated regulatory liability of $206 million (US$151 million) had been recognized as at December 31, 2018 based on the ALJ's initial decision.

In September 2016 FERC ordered that the base ROE for the Initial Refund Period be set at 10.32%, down from 12.38%, up to a maximum of 11.35% with incentive adders. The resultant rates applied prospectively from September 2016 until an approved ROE was established for the Second Refund Period. The total refund for the Initial Complaint as a result of the September 2016 FERC order was $158 million (US$118 million), including interest, and was paid in 2017.

The November 2019 FERC Order determined that the base ROE for the Initial Complaint and from September 2016 onward be 9.88%, up to a maximum of 12.24% with incentive adders. FERC also dismissed the Second Complaint, resulting in a ROE for that period of 12.38% plus incentive adders with no refund required. In addition, as an ROE complaint had not been filed for the period of May 2016 to September 2016, the ROE for that period continued to be 12.38% plus incentive adders with no refund required. The regulated utilities in the MISO region, including ITC, sought rehearing of this order on the basis that it will not allow utilities to earn a reasonable rate of return on investment. In January 2020 FERC issued an order granting the rehearing for further consideration, effectively extending FERC's review.

As at December 31, 2019, a regulatory liability of $91 million (US$70 million) was recognized related to the impact of the November 2019 FERC Order on the Initial Refund Period and for the period from September 2016 to December 2019. Additionally, the regulatory liability of $206 million (US$151 million) as at December 31, 2018, related to the Second Complaint, was reversed in 2019. The net impact of the November 2019 FERC Order was an increase in revenue and a decrease in interest expense resulting in an increase in net earnings of $79 million of which Fortis' share was $63 million. The favourable impact was comprised of: (i) $83 million related to the net reversal of liabilities established in prior periods; partially offset by (ii) $20 million related to the 2019 impact of a reduced ROE.

Based on the outcome of the request for rehearing, it is possible the ROE and refunds could materially change from those recognized in 2019.

Notices of Inquiry
In March 2019 FERC issued a NOI seeking comments on whether and how to improve its electric transmission incentives policy. The outcome may impact the existing incentive adders that are included in transmission rates charged by transmission owners, including ITC. Also in March 2019, FERC issued a second NOI seeking comments on whether and how recent policies concerning the determination of the base ROE for electric utilities should be modified. The comment period for both NOI proceedings has ended. The outcome may impact ITC's future ROE and incentive adders.

UNS Energy
General Rate Application
In April 2019 TEP filed a general rate application with the Arizona Corporation Commission requesting an increase in non-fuel revenue of US$99 million, effective May 1, 2020, with electricity rates based on a 2018 historical test year. Intervenor testimony in relation to TEP's revenue requirement and rate design was filed in October 2019. The application, adjusted for rebuttal testimony filed by TEP in November 2019, includes a request to increase TEP's allowed ROE to 10.00% from 9.75% and the equity component of its capital structure to 53% from 50% on a Rate Base of US$2.7 billion. Hearings before the ALJ commenced in January and a decision is expected by mid-2020.

FortisBC Energy and FortisBC Electric
In March 2019 FortisBC Energy and FortisBC Electric filed applications with the BCUC requesting approval of a multi-year rate plan and PBR methodology for 2020-2024. A decision is expected in mid-2020.

FortisAlberta

Second-Term Performance-Based Rate-Setting Proceeding

The AUC has ongoing proceedings to review regulatory applications for rebasing inputs included in PBR rates for 2018-2022, including anomaly-related adjustments and approved changes to depreciation parameters.

In January 2020 the AUC issued two decisions: (i) confirming that changes to depreciation parameters will be incorporated into incremental funding mechanisms; and (ii) establishing new criteria for anomaly-related adjustments. PBR utilities in Alberta are permitted to file depreciation studies by July 2020 and were required to submit their intent to file an anomaly-related adjustment application by February 7, 2020. FortisAlberta does not anticipate filing a depreciation study in 2020 and did notify the AUC of its intent to file an anomaly-related adjustment application.

Generic Cost of Capital Proceeding

In December 2018 the AUC initiated a generic cost of capital proceeding to consider a formula-based approach to setting the allowed ROE beginning in 2021 and whether any process changes are necessary for determining capital structure in years in which a ROE formula is in place. In April 2019 the AUC determined that a traditional non-formulaic approach for assessing ROE and deemed capital structure would be used in 2021, with consideration of a formula-based approach for determining the allowed ROE for 2022 and subsequent years. Expert evidence was filed in January 2020 with an oral hearing scheduled for April 2020. An AUC decision is expected later in 2020.

2018 Alberta Independent System Operator Tariff Application

In September 2019 the AUC issued a decision that addressed, among other things, a proposal to change how the AESO's customer contribution policy is accounted for between distribution facility owners, such as FortisAlberta, and transmission facility owners. The decision prevents any future investment by FortisAlberta under the policy and directs that the unamortized customer contributions of approximately $400 million as at December 31, 2017, which form part of FortisAlberta's Rate Base, be transferred to the incumbent transmission facility owner in FortisAlberta's service area.

In October 2019 FortisAlberta filed evidence to oppose the decision. Implementation of the order has been suspended and the decision remains under review by the AUC. It is expected that the decision will remain under review through the first quarter of 2020. The likely outcome of this process and potential impacts, if any, cannot be determined at this time.

FINANCIAL POSITION

Significant Changes between December 31, 2019 and 2018			
	Increase (Decrease)		
	FX	Other	
Balance Sheet Account	*($ millions)*	*($ millions)*	**Explanation**
Assets held for sale	—	(766)	Due to the disposition of the Waneta Expansion.
Regulatory assets (including current and long-term)	(55)	363	Due primarily to the operation of rate stabilization accounts and the normal deferral of derivative losses, energy management costs, income tax expense and employee future benefits.
Property, plant and equipment, net	(974)	2,205	Due primarily to capital expenditures, partially offset by depreciation.
Goodwill	(527)	1	The other increase was not significant.
Short-term borrowings	(2)	454	Due primarily to the issuance of commercial paper at ITC and short-term borrowings at UNS Energy.

Significant Changes between December 31, 2019 and 2018			
	Increase (Decrease)		
	FX	Other	
Balance Sheet Account	*($ millions)*	*($ millions)*	Explanation
Other liabilities	(32)	340	Due primarily to higher employee future benefits mainly at FortisBC Energy, and finance lease reclassifications and the balance sheet recognition of operating leases in accordance with the new lease standard (see "New Accounting Policies" on page 33). The increase was also due to higher derivative balances and asset retirement obligations primarily at UNS Energy.
Regulatory liabilities (including current and long-term)	(130)	(138)	Due primarily to the ROE complaints liability at ITC and lower deferred taxes.
Deferred income tax liabilities	(70)	353	Due primarily to the timing differences related to capital expenditures.
Long-term debt (including current portion)	(791)	(1,103)	Due primarily to the repayment of Corporate debt (see "Significant Items" on page 3), partially offset by the issuance of debt at the regulated utilities.
Finance leases (including current portion)	(12)	(193)	Due primarily to the purchase of Gila River Unit 2, partially offset by the recognition of a finance lease for Springerville Common Facilities at TEP. The decrease was also due to reclassifications to other liabilities as noted above.
Shareholders' equity	(585)	2,583	Due primarily to: (i) the issuance of common shares (see "Significant Items" on page 3); and (ii) Common Equity Earnings for 2019, less dividends declared on common shares.
Non-controlling interests	(75)	(266)	Due primarily to the disposition of the Waneta Expansion.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOW REQUIREMENTS

At the subsidiary level, it is expected that operating and interest costs will be paid from Operating Cash Flows, with varying levels of residual cash flows available for capital expenditures and/or dividend payments to Fortis. Capital expenditures are expected to be financed primarily from borrowings under credit facilities, long-term debt offerings and equity injections from Fortis. Borrowings under credit facilities may be required periodically to support seasonal working capital requirements.

Cash required of Fortis to support subsidiary capital expenditures is expected to be derived from borrowings under the Corporation's committed credit facility, proceeds from the DRIP and issuances of common shares, preference shares and long-term debt. Depending on the timing of subsidiary dividend receipts, borrowings under the Corporation's credit facility may be required periodically to support debt servicing and dividend payments.

Within this dynamic, the subsidiaries pay dividends to Fortis and receive equity injections from Fortis when required, and both Fortis and its subsidiaries initially borrow through their committed credit facilities and periodically replace these borrowings with long-term debt. Financing needs also arise periodically for acquisitions.

Credit facilities are syndicated primarily with large banks in Canada and the US, with no one bank holding more than 20% of the total facilities. Approximately $5.1 billion of the total credit facilities are committed with maturities ranging from 2020 through 2024. Available credit facilities are summarized in the following table.

Credit Facilities As at December 31 *($ millions)*	Regulated Utilities	Corporate and Other	**2019**	2018
Total credit facilities [1]	4,209	1,381	**5,590**	5,165
Credit facilities utilized:				
Short-term borrowings	(512)	—	**(512)**	(60)
Long-term debt (including current portion)	(640)	—	**(640)**	(1,066)
Letters of credit outstanding	(64)	(50)	**(114)**	(119)
Credit facilities unutilized	2,993	1,331	**4,324**	3,920

[1] *Additional information about these credit facilities is provided in Note 15 in the 2019 Annual Financial Statements.*

The Corporation's ability to service debt and pay dividends is dependent on the financial results of, and the related cash payments from, its subsidiaries. Certain regulated subsidiaries are subject to restrictions that limit their ability to distribute cash to Fortis, including restrictions by certain regulators limiting annual dividends and restrictions by certain lenders limiting debt to total capitalization. There are also practical limitations on using the net assets of the regulated subsidiaries to pay dividends, based on management's intent to maintain the subsidiaries' regulator-approved capital structures. Fortis does not expect that maintaining such capital structures will impact its ability to pay dividends in the foreseeable future.

In December 2018 Fortis filed a short-form base shelf prospectus with a 25-month life under which it may issue common or preference shares, subscription receipts or debt securities in an aggregate principal amount of up to $2.5 billion. In December 2018 Fortis re-established its ATM Program, which allowed the issuance of up to $500 million of common shares from treasury to the public at the Corporation's discretion, effective until January 2021.

During 2019 the Corporation issued approximately 4.1 million common shares under its ATM Program at an average price of $52.16 per share. The gross proceeds of $212 million ($209 million net of commissions) were used primarily to fund capital expenditures. Also in 2019, the Corporation issued approximately 22.8 million common shares under a common equity offering at a price of $52.15 per share for gross proceeds of $1,190 million ($1,167 million net of commissions). See "Significant Items" on page 3. Following this issuance, the Corporation terminated the ATM Program. As at December 31, 2019, $1,098 million remained available under the short-form base shelf prospectus.

As at December 31, 2019: (i) consolidated fixed-term debt maturities/repayments are expected to average $945 million annually over the next five years; (ii) approximately 80% of the Corporation's consolidated long-term debt, excluding credit facility borrowings, had maturities beyond five years; and (iii) available credit facilities were $5.6 billion with $4.3 billion unutilized.

This combination of available credit facilities and manageable annual debt maturities/repayments provides flexibility in the timing of access to capital markets. Given current credit ratings and capital structures, the Corporation and its subsidiaries expect to continue to have reasonable access to long-term capital in 2020.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2019 and are expected to remain compliant in 2020.

CASH FLOW SUMMARY

Summary of Cash Flows Years ended December 31 *($ millions)*	**2019**	2018	Variance
Cash, beginning of year	**332**	327	5
Cash provided by (used in):			
Operating activities	**2,663**	2,604	59
Investing activities	**(2,768)**	(3,252)	484
Financing activities	**154**	644	(490)
Effect of exchange rate changes on cash and cash equivalents	**(26)**	24	(50)
Cash and change in cash associated with assets held for sale	**15**	(15)	30
Cash, end of year	**370**	332	38

Operating Activities

See "Performance at a Glance - Operating Cash Flow" on page 5.

Investing Activities

Cash used in investing activities reflects a higher capital spending level in 2019. See "Performance at a Glance - Capital Expenditures" on page 5 and "Capital Plan" on page 21. Cash used in investing activities was partially offset by proceeds from the disposition of the Waneta Expansion.

Financing Activities

Cash flows related to financing activities will fluctuate from year to year as a result of changes in the subsidiaries' capital expenditures, the amount of Operating Cash Flows available to fund those capital expenditures and the amount of funding required from debt and common equity issuances.

In the fourth quarter of 2019, the Corporation issued approximately 22.8 million common shares at a price of $52.15 per share for gross proceeds of $1,190 million ($1,167 million net of commissions). The net proceeds were used to redeem US$500 million of its outstanding 2.10% unsecured senior notes due October 4, 2021, to repay credit facility borrowings and for general corporate purposes.

Net proceeds from the disposition of the Waneta Expansion were used to repay credit facility borrowings and repurchase, via a tender offer, US$400 million of its outstanding 3.055% unsecured senior notes due in 2026.

Debt Financing

Long-Term Debt Issuances Year ended December 31, 2019 *($ millions, except %)*	**Month Issued**	**Interest Rate** *(%)*	**Maturity**		**Amount**	**Use of Proceeds**
ITC						
Secured notes	January	4.55	2049	US	50	*(1) (2) (3)*
Unsecured term loan credit agreement *(4)*	June	*(5)*	2021	US	200	*(6)*
Secured notes	July	4.65	2049	US	50	*(1) (2) (3)*
First mortgage bonds	August	3.30	2049	US	75	*(1) (2) (3)*
Central Hudson						
Unsecured notes	October	3.89	2049	US	50	*(2) (3) (6)*
Unsecured notes	October	3.99	2059	US	50	*(2) (3) (6)*
FortisBC Energy						
Unsecured debentures	August	2.82	2049		200	*(1)*
FortisTCI						
Unsecured non-revolving term loan	February	*(7)*	2025	US	5	*(2) (3)*
Caribbean Utilities						
Unsecured notes	May	4.14	2049	US	40	*(1) (3) (6)*
Unsecured notes	August	4.14	2049	US	20	*(2) (3) (6)*
Unsecured notes	August	3.83	2039	US	20	*(2) (3) (6)*

(1) *Repay credit facility borrowings*
(2) *Finance capital expenditures*
(3) *General corporate purposes*
(4) *Maximum amount of borrowings under this agreement was US$400 million; in January 2020 the remaining US$200 million was drawn to repay outstanding commercial paper balances*
(5) *Floating rate of a one-month LIBOR plus a spread of 0.60%*
(6) *Repay maturing long-term debt*
(7) *Floating rate of a one-month LIBOR plus a spread of 1.75%*

In January 2020 ITC entered into an unsecured term loan credit agreement, due in January 2021, under which the maximum amount of US$75 million was borrowed. The proceeds were used to repay credit facility borrowings.

Common Equity Financing

Common Equity Issuances and Dividends Paid Years Ended December 31 *($ millions, except as indicated)*	**2019**	2018	Variance
Number of common shares issued *(1)* *(# millions)*	**34.8**	7.4	27.4
Amount of common shares issued (2)	**1,756**	307	1,449
Non-cash issuances *(3)*	**(314)**	(273)	(41)
Cash proceeds from common shares issued	**1,442**	34	1,408
Dividends paid per common share *($)*	**1.8275**	1.7250	0.1025
Total dividends paid	**793**	731	62
Non-cash DRIP	**(299)**	(272)	(27)
Cash dividends paid	**494**	459	35

(1) *Mainly related to the Corporation's issuance of shares in the fourth quarter of 2019, DRIP and ATM Program*
(2) *Net of commissions of $26 million (2018 - $nil)*
(3) *Related to DRIP and stock options*

On February 12, 2020, Fortis declared a dividend of $0.4775 per common share payable on June 1, 2020. The payment of dividends is at the discretion of the Board of Directors and depends on the Corporation's financial condition and other factors.

CONTRACTUAL OBLIGATIONS

Contractual Obligations As at December 31, 2019 ($ millions)	Total	Due Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Long-term debt:							
Principal [1]	**22,320**	690	872	1,146	1,553	1,106	16,953
Interest	**15,483**	929	910	879	846	786	11,133
Finance leases [2]	**1,359**	56	121	33	33	33	1,083
Other obligations	**450**	134	120	94	20	19	63
Other commitments [3]							
Waneta Expansion capacity agreement	**2,628**	51	52	53	54	55	2,363
Gas and fuel purchase obligations	**2,398**	606	424	349	255	140	624
Power purchase obligations	**1,743**	244	183	168	163	119	866
Renewable PPAs	**1,513**	104	104	104	103	103	995
Build-transfer agreement - Oso Grande	**438**	438	—	—	—	—	—
ITC easement agreement	**401**	13	13	13	13	13	336
Renewables energy credit purchase agreements	**124**	26	18	17	10	10	43
Debt collection agreement	**116**	3	3	3	3	3	101
Other	**299**	36	26	24	25	29	159
	49,272	3,330	2,846	2,883	3,078	2,416	34,719

(1) *Total is not reduced by unamortized deferred financing and discount costs of $129 million.*
(2) *Additional information is provided in Note 16 in the 2019 Annual Financial Statements.*
(3) *Additional information is provided in Note 29 in the 2019 Annual Financial Statements.*

Other Contractual Obligations

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. Consolidated capital expenditures are forecast to be approximately $4.3 billion for 2020 and approximately $18.8 billion over the five-year period from 2020 through 2024. See "Capital Plan" on page 21.

Under a funding framework with the Governments of Ontario and Canada, Fortis will contribute a minimum of approximately $155 million of equity capital to the Wataynikaneyap Partnership, based on Fortis' proportionate 39% ownership interest and the final regulatory-approved capital cost of the related project. In October 2019 the Wataynikaneyap Partnership entered into loan agreements to finance the project during construction. In the event a lender under such construction loan agreements realizes security on the loans, Fortis may be required to accelerate its equity capital contributions, which may be in excess of the amount otherwise required of Fortis under the funding framework, to a maximum total funding of $235 million.

As at December 31, 2019, FortisBC Holdings Inc., a non-regulated holding company, had $78 million of parental guarantees outstanding to support storage optimization activities at Aitken Creek.

Off-Balance Sheet Arrangements

With the exception of letters of credit outstanding of $114 million as at December 31, 2019 and the unrecorded commitments in the table above, the Corporation had no off-balance sheet arrangements.

CAPITAL STRUCTURE AND CREDIT RATINGS

Fortis requires ongoing access to capital and, therefore, targets a consolidated long-term capital structure that will enable it to maintain investment-grade credit ratings. The regulated utilities maintain their own capital structures in line with those reflected in customer rates.

Consolidated Capital Structure [1] (%)		
As at December 31	**2019**	2018
Debt [2]	**53.1**	57.0
Preference shares	**3.8**	3.8
Common shareholders' equity and minority interest [3]	**43.1**	39.2
	100.0	100.0

(1) *Reflects the repayment of debt using proceeds from the disposition of the Waneta Expansion and the $1.2 billion common equity offering (see "Significant Items" on page 3)*
(2) *Includes long-term debt and finance leases, including current portion, and short-term borrowings, net of cash*
(3) *Includes minority interest of 3.7% as at December 31, 2019 (December 31, 2018 - 4.5%)*

Outstanding Share Data
As at February 12, 2020, the Corporation had issued and outstanding 463.5 million common shares and the following First Preference Shares: 5.0 million Series F; 9.2 million Series G; 7.0 million Series H; 3.0 million Series I; 8.0 million Series J; 10.0 million Series K; and 24.0 million Series M.

Only the common shares of the Corporation have voting rights. The Corporation's first preference shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive or declared.

If all outstanding stock options were converted as at February 12, 2020, an additional 3.2 million common shares would be issued and outstanding.

Credit Ratings
The Corporation's credit ratings shown below reflect its low risk profile, diversity of operations, the stand-alone nature and financial separation of each regulated subsidiary, and level of holding company debt.

Credit Ratings As at December 31, 2019	Rating	Type	Outlook
S&P	A-	Corporate	Negative
	BBB+	Unsecured debt	
DBRS Morningstar	BBB (high)	Corporate	Stable
	BBB (high)	Unsecured debt	
Moody's	Baa3	Issuer	Stable
	Baa3	Unsecured debt	

CAPITAL PLAN

Capital investment in energy infrastructure is required to ensure the continued and enhanced performance, reliability and safety of the electricity and gas systems, and to meet customer growth. See "Performance at a Glance - Capital Expenditures" on page 5.

2019 Capital Expenditures [1]

	Regulated Utilities										
($ millions, except %)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated [2]**	**Total**	**(%)**
Generation	—	442	2	—	—	29	57	**530**	**6**	**536**	**14**
Transmission	951	83	55	194	—	18	146	**1,447**	**—**	**1,447**	**38**
Distribution	—	255	174	191	385	42	160	**1,207**	**—**	**1,207**	**32**
Other [3]	197	135	86	78	38	17	30	**581**	**47**	**628**	**16**
Total	1,148	915	317	463	423	106	393	**3,765**	**53**	**3,818**	**100**
(%)	31	24	8	12	11	3	10	**99**	**1**	**100**	

(1) *Reflects cash outlay for property, plant and equipment and intangible assets as shown on the consolidated statements of cash flows in the 2019 Annual Financial Statements, as well as Fortis' share of development costs and capital spending for the Wataynikaneyap Transmission Power Project of $98 million*
(2) *Includes Energy Infrastructure and Corporate and Other segments*
(3) *Includes facilities, equipment, vehicles and information technology assets, as well as AESO transmission-related capital expenditures at FortisAlberta*

Planned capital expenditures are based on detailed forecasts of energy demand, labour and material costs, general economic conditions, foreign exchange rates and other factors. These could change and cause actual expenditures to differ from forecast or plan.

Forecast 2020 Capital Expenditures [(1)]

	Regulated Utilities										
($ millions, except %)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated**	**Total**	***(%)***
Generation	—	715	1	—	—	33	120	**869**	**11**	**880**	**20**
Transmission	914	189	44	221	—	4	254	**1,626**	**—**	**1,626**	**37**
Distribution	—	274	167	153	365	77	158	**1,194**	**—**	**1,194**	**28**
Other	62	212	80	133	71	27	34	**619**	**21**	**640**	**15**
Total	976	1,390	292	507	436	141	566	**4,308**	**32**	**4,340**	**100**
(%)	22	32	7	12	10	3	13	**99**	**1**	**100**	

(1) *Excludes the non-cash equity component of AFUDC*

Five-Year Capital Plan [(1)]

($ billions)	2020	2021	2022	2023	2024	**Total**
	4.3	3.8	3.8	3.7	3.2	**18.8**

(1) *Excludes the non-cash equity component of AFUDC*

The Corporation's five-year 2020-2024 capital plan of $18.8 billion is $0.5 billion higher than the $18.3 billion capital plan disclosed in the Q3 2019 MD&A due to a $0.5 billion shift in spending to 2020 and 2021 (see "Performance at a Glance - Capital Expenditures" on page 5).

The $18.8 billion five-year capital plan is $1.5 billion higher than the $17.3 billion for 2019-2023, as disclosed in the 2018 annual MD&A, largely due to: (i) expected grid enhancements and cleaner energy resources at ITC and Caribbean Utilities; (ii) expected expansion of the Tilbury LNG site at FortisBC Energy; (iii) an increase in the forecast foreign exchange rate from US$1.00=CAD$1.28 to US$1.00=CAD$1.32; and (iv) the above-noted shift in spending from 2019 to 2020 and 2021.

The capital plan is low risk and highly executable, with 99% of planned expenditures to occur at the regulated utilities and only 20% related to Major Capital Projects. Geographically, 55% of planned expenditures are expected in the US, including 26% at ITC, with 41% in Canada and the remaining 4% in the Caribbean.

Nature of Capital Expenditures *(%)*	**Actual 2019**	Forecast 2020	Five-Year Plan 2020-2024
Growth [(1)]	**23**	25	28
Sustaining [(2)]	**60**	62	59
Other [(3)]	**17**	13	13
Total	**100**	100	100

(1) *Relates to the connection of new customers and infrastructure upgrades required to meet load growth, including AESO transmission-related investment at FortisAlberta*
(2) *Relates to the continued and enhanced performance, reliability and safety of generation, transmission and distribution assets*
(3) *Facilities, equipment, vehicles, information technology and other assets*

Midyear Rate Base (1) *($ billions)*	**Actual 2019**	Forecast 2020	Forecast 2024
ITC	**8.7**	9.5	12.0
UNS Energy	**5.1**	5.8	6.9
Central Hudson	**1.9**	2.1	2.8
FortisBC Energy	**4.5**	5.0	6.6
FortisAlberta	**3.5**	3.7	4.3
FortisBC Electric	**1.3**	1.4	1.5
Other Electric	**3.0**	3.2	4.3
Total	**28.0**	30.7	38.4

(1) *Simple average of Rate Base at beginning and end of the year*

Total midyear Rate Base is forecast to grow to $38.4 billion by 2024 under the five-year capital plan, representing a CAGR of 6.5%, which is supportive of continuing growth in earnings and dividends.

Major Capital Projects (1)				Forecast		
($ millions)	Project	Pre-2019	**Actual 2019**	2020	2021-2024	Expected Completion
ITC (2)	Multi-Value Regional Transmission Projects	581	**44**	11	265	2023
	34.5 to 69 kV Transmission Conversion Project	225	**127**	92	176	Post-2024
UNS Energy	Gila River Unit 2	—	**212**	—	—	2019
	Southline Transmission Project	—	**—**	19	373	Post-2024
	Oso Grande Wind Project	—	**65**	453	—	2020
FortisBC Energy	Lower Mainland Intermediate Pressure System Upgrade	208	**180**	72	—	2020
	Eagle Mountain Woodfibre Gas Line Project (3)	—	**—**	—	350	2023
	Transmission Integrity Management Capabilities Project	—	**13**	23	494	Post-2024
	Inland Gas Upgrades Project	3	**6**	57	262	Post-2024
	Tilbury 1B	—	**8**	37	315	2024
Other Electric	Wataynikaneyap Transmission Power Project (4)	25	**98**	230	271	2023
Total		1,042	**753**	994	2,506	

(1) *Includes applicable AFUDC*
(2) *Pre-2019 capital expenditures are from the date of the ITC acquisition on October 14, 2016*
(3) *Net of forecast customer contributions*
(4) *Fortis' share of estimated capital spending, including deferred development costs. Under the funding framework, Fortis will be funding its equity component only.*

Multi-Value Regional Transmission Projects
Consists of four regional electric transmission projects that have been identified by MISO to address system capacity needs and reliability in various states. Three projects have been completed, one in 2018 and two in 2019. The fourth project is expected to be placed in service in 2023.

34.5 to 69kV Transmission Conversion Project
Consists of multiple capital initiatives designed to construct new 69-kV lines, and upgrade existing 34.5-kV lines to 69 kV, with in-service dates ranging from 2019 to post-2024.

Gila River Unit 2
In 2017 UNS Energy entered into a 20-year tolling PPA that included a three-year option to purchase Gila River Unit 2. The purchase of Gila River Unit 2 was completed in December 2019 and replaces the early retirement of coal-fired generation.

Southline Transmission Project
UNS Energy continues to evaluate the cost and timelines associated with the different phases of this project. The first phase, referred to as "Vail-to-Tortolita", is a joint effort between Western Area Power Administration and TEP that will result in new construction and upgrades to connect existing TEP substations. Construction of this phase is expected to commence in 2020.

The second phase of the project relates to the construction of a 600-MW transmission line across southern New Mexico and southern Arizona. The line will improve regional reliability and facilitate the connection of renewable energy resources to the grid, including the Oso Grande Wind Project. UNS Energy expects to purchase a 250-MW ownership in the project. The timing, share and cost of this phase of the project will depend on subscription of the remaining wind available at Oso Grande.

Oso Grande Wind Project
Relates to the construction of a 750-MW wind-powered electric generating facility that will complement UNS Energy's existing renewable solar generation portfolio, of which UNS Energy will own 250 MW. Construction on Oso Grande commenced in the third quarter of 2019 and in January 2020 UNS Energy took ownership of its share under a build-transfer contract. Construction is expected to be completed for operation by December 2020.

Lower Mainland Intermediate Pressure System Upgrade
Addresses system capacity and pipeline condition issues for the gas supply system in the Lower Mainland of British Columbia. The Burnaby and Coquitlam sections of the project were gasified during 2018 and 2019. A short pipeline segment in South Vancouver will be replaced in 2020. Final allowable project costs are subject to review by the BCUC.

Eagle Mountain Woodfibre Gas Line Project
Consists of a pipeline expansion to a proposed LNG site in Squamish, British Columbia. Cost estimates are subject to final project scoping and determination of customer capital contributions. An Order in Council from the Government of British Columbia effectively exempts the project from further regulatory approval. FortisBC Energy and Woodfibre LNG Limited have entered into a pre-execution work agreement enabling FortisBC Energy to incur project feasibility and development costs.

Transmission Integrity Management Capabilities Project
Project to improve gas line safety and transmission system integrity, including gas line modifications and looping. In December 2018 a regulatory deferral account was approved by the BCUC to capture approximately $40 million of development costs to be incurred through 2020 to enable the filing for a CPCN.

Inland Gas Upgrades Project
Relates to gas line modifications and replacements to enable in-line integrity inspection capabilities. In January 2020 the CPCN application was approved by the BCUC.

Tilbury 1B Project
Consists of construction of additional liquefaction and dispensing in support of optimizing the existing investment in Tilbury Phase 1A Expansion Project. The project has received an Order in Council from the Government of British Columbia. Pre-front-end engineering design and related studies will continue in 2020.

Wataynikaneyap Transmission Power Project
Consists of the construction of a $1.6 billion, 1,800 kilometre, OEB-regulated transmission line to connect 17 remote First Nations communities in Northwestern Ontario to the main electricity grid. FortisOntario is responsible for construction management and operation of the transmission line. The initial phase to connect the Pikangikum First Nation was fully funded by the Canadian government and completed in late 2018. In the fourth quarter of 2019, the project received financial close and a notice to proceed for construction was issued. The project is targeted for completion by the end of 2023.

Additional Investment Opportunities
Fortis is pursuing additional investment opportunities within existing service territories that are not yet included in the base five-year capital plan.

ITC - Lake Erie Connector
Relates to a proposed 1,000 MW, bi-directional, high-voltage direct current underwater transmission line to directly link the markets of the Ontario Independent Electricity System Operator and PJM Interconnection, LLC. The project would enable transmission customers to more efficiently access energy, capacity and renewable energy credit opportunities in both markets. The major application process is complete. The project continues to advance through regulatory, operational and economic milestones. Ongoing activities include completing project cost refinements and securing transmission service agreements. Completion would take approximately three years from the commencement of construction.

FortisBC Energy - LNG
Relates to FortisBC's pursuit of additional LNG infrastructure opportunities in British Columbia, including further expansion of the Tilbury LNG facility, which is uniquely positioned to meet customer demand for clean-burning natural gas. The site is scalable and can accommodate additional storage and liquefaction equipment and is relatively close to international shipping lanes. Fortis continues to have discussions with potential export customers.

Other Opportunities
Includes incremental regulated transmission investment, contracted transmission and grid modernization projects at ITC; renewable energy investments, energy storage projects, grid modernization, infrastructure resiliency, and transmission investments at UNS Energy; and further gas infrastructure opportunities at FortisBC Energy.

BUSINESS RISKS

Fortis has established an ERM process to help identify and evaluate risks by both severity of impact and probability of occurrence. Materiality thresholds are reviewed and, if necessary, updated annually. Non-financial risks that may impact the safety of employees, customers or the general public, as well as reputational risks, are also evaluated. Systems of internal controls are established to monitor and manage identified risks. The ERM process at the subsidiary level is overseen by each subsidiary’s board and any material risks identified are communicated to Fortis management and form part of Fortis' ERM program. The Fortis board, through the audit committee, oversees Fortis' ERM program, ensuring strategic objectives are achieved.

A summary of the Corporation's current significant business risks follows.

Regulation
Regulated utility assets represented approximately 99% of the Corporation's total assets as at December 31, 2019. Regulatory jurisdictions include five Canadian provinces, nine US states and three Caribbean countries, as well FERC regulation for transmission assets in the US.

Regulators administer legislation covering material aspects of the utilities' business, including: customer rates and the underlying allowed ROEs and deemed capital structures; capital expenditures; the terms and conditions for the provision of energy and capacity, ancillary services and affiliate services; securities issuances; and certain accounting matters. Regulatory or legislative changes and decisions, and delays in the recovery of costs in rates due to regulatory lag, could have a Material Adverse Effect. The risk of regulatory lag is particularly significant for UNS Energy given the use of historical test years in setting rates.

The ability to recover the actual cost of service and earn the approved ROE or ROA typically depends on achieving the forecasts established in the rate-setting process. Failure to do so could have a Material Adverse Effect. For those utilities subject to PBR mechanisms, rates reflect assumed inflation rates and productivity improvement factors, and variances therefrom could have a Material Adverse Effect. Under FortisAlberta's PBR mechanism there is an added risk that incremental incurred capital expenditures may not be approved for recovery in rates.

For transmission operations, the underlying elements of FERC-established formula rates can be, and have been, challenged by third parties which could result in, and has resulted in, lowered rates and customer refunds. These underlying elements include the assumed ROE and deemed capital structure as well as operating and capital expenditures. These challenges could have a Material Adverse Effect. Recent challenges are described under "Regulatory Highlights - ITC" on page 13.

Additionally, the US Congress periodically considers enacting energy legislation that could assign new responsibilities to FERC, modify provisions of the *U.S. Federal Power Act* or the *Natural Gas Act*, or provide FERC or another entity with increased authority to regulate US federal energy matters. Such changes could have a Material Adverse Effect.

The political and economic environments as well as their effect on energy laws and governmental energy policies have had, and may continue to have, negative impacts on regulatory decisions. While Fortis is well positioned to maintain constructive regulatory relationships through local management teams and boards comprised mostly of independent local members, it cannot predict future legislative or regulatory changes, whether caused by economic, political or other factors, or its ability to respond thereto in an effective and timely manner, or resulting compliance costs. These dynamics could have a Material Adverse Effect.

Climate Change and Physical Risks

The provision of electric and gas service is subject to customary industry risks, including severe weather and natural disasters, wars, terrorism, critical equipment failure and other catastrophic events within and outside the Corporation's service territories. Resultant service disruption and repair and replacement costs could have a Material Adverse Effect if not resolved in a timely and effective manner and/or mitigated through insurance policies or regulatory cost recovery.

Climate change is predicted to lead to more frequent and intense weather events, changing air temperatures, changing seasonal variations, and regulatory responses (see "Environmental Matters" on page 31), each of which could have a Material Adverse Effect. Severe weather impacts the Corporation's service territories, primarily when thunderstorms, flooding, wildfires, hurricanes and snow or ice storms occur. Increased frequency of extreme weather events could increase the cost of providing service. Changes in precipitation that result in droughts could increase the risk of wildfire caused by the Corporation's electricity assets or may cause water shortages that could adversely affect operations. Extreme weather conditions in general require system backup and can contribute to increased system stress, including service interruptions. Changing air temperatures could also result in system stress and decreased efficiencies over time to operating facilities. Longer-term climate change impacts, such as sustained higher temperatures, higher sea levels and larger storm surges, could result in service disruption, repair and replacement costs, and costs associated with strengthened design standards and systems, each of which could have a Material Adverse Effect if not resolved in a timely and effective manner and/or mitigated through insurance policies or regulatory cost recovery.

Generating equipment and facilities are subject to risks, including equipment breakdown and flood and fire damage, that may result in the uncontrolled release of water, interruption of fuel supply, lower-than-expected operational efficiency or performance, and service disruption. There is no assurance that generating equipment and facilities will continue to operate in accordance with expectations.

The operation of transmission and distribution assets is subject to risks, including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. Certain utilities operate in remote and mountainous terrain that can be difficult to access for timely repairs and maintenance, or otherwise face risk of loss or damage from forest fires, floods, washouts, landslides, earthquakes, avalanches and other acts of nature with a potential Material Adverse Effect.

The gas utilities are exposed to operational risks associated with natural gas, including fires, explosions, pipeline corrosion and leaks, accidental damage to mains and service lines, equipment failure, damage and destruction from earthquakes, fires, floods and other natural disasters, and other accidents and issues that can lead to service disruption, spills and commensurate environmental liability, or other liability with a Material Adverse Effect.

Risks associated with fire damage vary depending on weather, forestation, the proximity of habitation and third-party facilities to utility facilities, and other factors. The utilities may become liable for fire-suppression costs, regeneration and timber value costs, and third-party claims if their facilities are held responsible for a fire, and such claims, if successful, could have a Material Adverse Effect.

Electricity and gas systems require ongoing maintenance, improvement and replacement. Service disruption, other effects and liability caused by the failure to properly implement or complete approved maintenance and capital expenditures, or the occurrence of significant unforeseen equipment failures despite maintenance programs, or the inability to recover requisite costs in customer rates, could have a Material Adverse Effect.

The electricity and gas systems are designed to service customers under various contingencies in accordance with good utility practice. The utilities are responsible for operating and maintaining their assets in a safe manner, including the development and application of appropriate standards, system processes and/or procedures to ensure the safety of employees, contractors and the general public. The impacts of climate change may necessitate the acceleration of these standards, processes and procedures. Failure to do so may disrupt the ability of the utilities to safely provide service, which could cause reputational harm and other impacts with a Material Adverse Effect.

Interest Rates

The market price of the Corporation's common shares is inversely sensitive to interest rate changes.

Additionally, allowed ROEs are exposed to changes in long-term interest rates. A low interest rate environment could reduce allowed ROEs. Alternatively, if interest rates rise, regulatory lag may cause delays in any compensatory ROE increases. Borrowings under variable-rate credit facilities and long-term debt, as well as new debt issuances, are also exposed to interest rate changes.

Weather Variability and Seasonality

Electricity consumption varies significantly in response to climate change and seasonal weather changes. In central and western Canada, Arizona and New York State, cool summers may reduce the use of air conditioning and other cooling equipment, while less severe winters may reduce heating load. Alternatively, severe weather could unexpectedly increase heating and cooling loads, negatively impacting system reliability.

Weather and seasonality have a significant impact on gas distribution volumes as a major portion of the gas is used for space heating by residential customers. The earnings of the Corporation's gas utilities and Aitken Creek are typically highest in the first and fourth quarters.

Hydroelectric generation is sensitive to rainfall levels.

Regulatory deferral and revenue decoupling mechanisms are in place at certain of the Corporation's utilities to minimize the volatility in earnings that would otherwise be caused by variations in weather conditions. Both the discontinuance of key regulatory mechanisms and their absence at other Fortis entities could result in significant and prolonged weather variations from seasonal norms having a Material Adverse Effect.

Growth

Fortis has a history of growth through acquisitions and organic growth from capital expenditures in existing service territories. Acquisitions include inherent risks that some or all of the expected benefits may fail to materialize, or may not occur within the time periods anticipated, and material unexpected costs may arise.

The Corporation's dividend growth guidance is significantly dependent upon achieving the Rate Base growth expected from the execution of the five-year capital plan described under "Capital Plan" on page 21. Projects, particularly Major Capital Projects, are subject to risks of delay and cost overruns during construction caused by inflation, supply and labour costs, supplier non-performance, weather, geologic conditions or other factors beyond the Corporation’s control. There is no assurance that regulators will approve (i) all of the planned projects or their amounts or timing, (ii) permits in a timely manner, or with reasonable terms and conditions, or (iii) the recovery of overruns in customer rates. These risks could impact the successful execution of a project by preventing the project from proceeding, delaying its completion, increasing its projected costs or negatively impacting its financing.

Talent Management

The delivery of safe, reliable and cost-effective service depends on the attraction, development and retention of skilled workforces. Like its peers, Fortis faces demographic challenges and competitive markets relating to trades, technical and professional staff, particularly considering its significant consolidated capital plan. ITC relies heavily on agreements with third parties to provide services for the construction, maintenance and operation of certain aspects of its business. Although Fortis has a robust talent management program, there is no assurance it will be able to continue to attract sufficient and appropriate talent. Significant failures in these regards could have a Material Adverse Effect.

Tax Laws

Fortis and its subsidiaries are subject to changes in income tax rates and other tax legislation in Canada, the US and other international jurisdictions. These changes could have a Material Adverse Effect. Although income taxes at the regulated utilities are generally recovered in customer rates, regulatory lag can result in recovery delays or non-recovery for certain periods. A variety of other impacts are also possible. At the non-regulated level, changes in income tax rates and other tax legislation could materially affect the after-tax cost of existing and future debt which is not recoverable in customer rates.

The nature, timing or impact of any future changes in tax laws cannot be predicted. Additionally, certain aspects of US tax reform are still subject to interpretation and clarification, including proposed regulations regarding certain hybrid arrangements.

Cybersecurity

As operators of critical energy infrastructure, the Corporation's utilities face the risk of cybercrime, which has increased in frequency, scope and potential impact in recent years. Their ability to operate effectively is dependent upon developing and maintaining complex information systems and infrastructure that support the operation of electric generation, transmission and distribution facilities, including gas facilities; provide customers with billing, consumption and load settlement information, where applicable; and support financial and general operations.

Despite risk-based cybersecurity programs that have been implemented and are continuously monitored for effectiveness, information and operations technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, acts of vandalism and other causes. This can result in the disruption of energy service and other business operations, system failures and grid disturbances, property damage, corruption or unavailability of critical data, and the misappropriation and/or disclosure of sensitive, confidential and proprietary business, customer and employee information.

A material breach could adversely affect the financial performance of the Corporation, its reputation and standing with customers, regulators and financial markets, and expose it to claims for third-party damage. The resultant financial impacts may not be fully covered by insurance policies or, in the case of utilities, through regulatory cost recovery, and could have a Material Adverse Effect.

Technology Advances

The emergence of initiatives designed to reduce GHG emissions and control or limit the effects of climate change has increased the incentive for the development of new technologies that produce power, enable more efficient storage of energy or reduce power consumption.

New technology developments in distributed generation, particularly solar, and energy efficiency products and services, as well as the implementation of renewable energy and energy efficiency standards, will continue to impact retail sales. Heightened awareness of energy costs and environmental concerns have increased demand for products that reduce energy consumption. The Corporation's utilities are also promoting demand-side management programs.

New technologies include energy derived from renewable sources, customer-owned generation, energy-efficient appliances, battery storage and control systems. Advances in these or other technologies could have a significant impact on retail sales with a potential Material Adverse Effect.

Foreign Exchange Exposure
The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI, BECOL and Belize Electricity is, or is pegged to, the US dollar. The earnings and cash flows from, and net investments in, these entities are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate.

Fortis has limited this exposure through hedging. As at December 31, 2019, US$2.2 billion (December 31, 2018 - US$3.4 billion) of corporately issued US dollar-denominated long-term debt had been designated as an effective hedge of foreign net investments, leaving US$9.7 billion (December 31, 2018 - US$8.0 billion) in foreign net investments unhedged. Fortis has also entered into foreign exchange contracts to manage a portion of its exposure to foreign currency risk.

Given only partial hedging, consolidated earnings and cash flows continue to be impacted by exchange rate fluctuations. On average, Fortis estimates that a five-cent increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CAD$1.33 as at December 31, 2019 would increase or decrease annual EPS by approximately 6 cents, which reflects the Corporation's hedging program.

There is no assurance that existing hedging strategies will continue to be effective. They could also have the effect of limiting or reducing the Corporation's total returns if management's expectations concerning future events or market conditions prove to be incorrect, in which case the costs associated with the hedging strategies may outweigh their benefits.

Natural Gas Competitiveness
Approximately 19% of the Corporation's revenue is derived from natural gas. A decrease in the competitiveness of natural gas due to pricing or other factors could have a Material Adverse Effect.

In British Columbia, which accounts for 79% of the Corporation's natural gas revenue, natural gas primarily competes with electricity for space and hot water heating. Upfront capital costs for gas service continue to present competitive challenges for natural gas compared to electricity service. If gas becomes less competitive, the ability to add new customers could be impaired. Existing customers could also reduce their consumption or switch to electricity, placing further pressure on rates, whereby system costs must be recovered from a smaller customer and sales base, and leading to further reductions in competitiveness.

Government policy could also impact the competitiveness of natural gas in British Columbia. The provincial government has introduced changes to energy policy, including GHG emission reduction targets and a consumption tax on carbon-based fuels, but has not yet introduced a carbon tax on imported electricity generated through the combustion of carbon-based fuels. The impact of these changes to energy policy may have a material impact on the competitiveness of natural gas relative to non-carbon based energy sources or other energy sources.

In addition, all levels of government have become more active in the development of policies to address climate change. For example, municipal governments have developed policies and bylaws to support the transition to a lower-carbon economy. Government policy may put upward pressure on the cost of natural gas and potentially affect its competitiveness. Government policy may also impose limitations on energy sources permitted to be used in new and existing developments.

Reliability Standards
The *Energy Policy Act* requires owners, operators and users of the bulk electric system in the US to meet mandatory reliability standards developed by the North American Electric Reliability Corporation and its regional entities, which are approved and enforced by FERC. Many of these, or similar, standards have been adopted in certain Canadian provinces including British Columbia, Alberta and Ontario. The failure to develop, implement and maintain appropriate operating practices/systems and capital plans to address reliability obligations could lead to compliance violations and a Material Adverse Effect, such as the exclusion from customer rates of related costs including potentially significant penalties.

General Economic Conditions
Fluctuations in general economic conditions, energy prices, employment levels, personal disposable incomes, housing starts, industrial activity and other factors may lower energy demand and reduce sales both directly and through reduced capital spending, particularly that related to new customer growth, which would affect Rate Base growth. A severe and prolonged economic downturn could have a Material Adverse Effect despite compensatory regulatory measures, including making it more difficult for customers to pay their bills.

Access to Capital
Ongoing access to cost-effective capital is required to fund, among other things, capital expenditures and the repayment of maturing debt.

Operating Cash Flows may not be sufficient to fund the repayment of all outstanding liabilities when due or anticipated capital expenditures. The ability to meet long-term debt repayments is dependent upon obtaining sufficient and cost-effective financing to replace maturing indebtedness.

The ability to arrange such financing is subject to numerous factors, including the results of operations and financial condition of Fortis and its subsidiaries, the regulatory environments including regulatory decisions regarding capital structure and allowed ROEs, capital market conditions, general economic conditions and credit ratings. Changes in credit ratings could affect credit risk spreads on new long-term debt and credit facilities, as well as their availability.

There is no assurance that sufficient capital will continue to be available on acceptable terms. For further information see "Liquidity and Capital Resources" on page 16.

Commodity Price Volatility
Purchased power and generation fuel costs are subject to commodity price volatility, which is managed through regulator-approved: (i) mechanisms that permit the flow through in customer rates of commodity price changes and/or that provide for rate-stabilization and other deferral accounts (see "Business Unit Performance" on page 8); and (ii) price-risk management strategies such as the use of derivative contracts that effectively fix costs (see "Financial Instruments - Derivatives" on page 37).

There is no assurance that current regulator-approved mechanisms will continue to exist in the future. Additionally, despite these mechanisms, severe and prolonged commodity price increases could result in rates that customers are unable to pay and/or could affect consumption and thus sales growth. These could have a Material Adverse Effect.

Counterparty Credit Risk
ITC has a concentration of credit risk as approximately 70% of its revenue is derived from three customers. These customers have investment-grade credit ratings and credit risk is further managed by requiring a letter of credit or cash deposit equal to the credit exposure, which is determined by a credit-scoring model and other factors.

FortisAlberta has a concentration of credit risk as its distribution service billings are to a relatively small group of retailers. Credit risk is managed by obtaining from the retailers either a cash deposit, letter of credit, an investment-grade credit rating, or a financial guarantee from an entity with an investment-grade credit rating.

UNS Energy, Central Hudson, FortisBC Energy, Aitken Creek and Fortis may be exposed to credit risk from non-performance by counterparties to derivatives. Credit risk is managed by net settling payments, when possible, and dealing only with counterparties that have investment-grade credit ratings. At UNS Energy and Central Hudson, certain contractual arrangements require counterparties to post collateral.

There is no assurance that management strategies will continue to be effective. Significant counterparty defaults could have a Material Adverse Effect.

Purchased Power Supply
A significant portion of electricity and gas sold by the Corporation's utilities is purchased through the wholesale energy markets or pursuant to contracts with energy suppliers rather than being generated. A disruption in the wholesale energy markets, or a failure on the part of energy or fuel suppliers or operators of energy delivery systems that connect to the Corporation's utilities, could have a Material Adverse Effect.

Post-Retirement Obligations
Fortis and most of its subsidiaries maintain a combination of defined benefit pension and/or OPEB plans for certain employees and retirees. The most significant cost drivers for these plans are investment performance and interest rates, which are affected by global financial markets. Market disruptions, significant declines in the market values of investments held to meet plan obligations, discount rate changes, participant demographics, and changes in laws and regulations may require additional plan funding. Significant increases in plan expenses and funding could have a Material Adverse Effect.

Joint-Ownership Interests and Third-Party Operators
Certain generating facilities from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have sole discretion or any ability to affect the management or operations of such facilities, including how to best address changing economic conditions or environmental requirements that may affect the facilities. A divergence in the interests of TEP and those of the joint owners or operators could have a Material Adverse Effect.

Wataynikaneyap Partnership is a partnership, owned 51% by 24 First Nations communities and 49% by a partnership between Fortis (80%) and Algonquin Power & Utilities Corp. (20%), responsible for the Wataynikaneyap Transmission Power Project. Fortis does not have sole discretion on decisions for the project and divergence in the interest of Fortis and the other partners could delay the project’s completion, increase its anticipated cost, or adversely affect the reputation of Fortis.

Environmental Matters
The Corporation's businesses are subject to environmental risks and environmental laws and regulations, including those which: (i) impose limitations or restrictions on the discharge of pollutants into the air, soil and water; (ii) establish standards for the management, treatment, storage, transportation and disposal of hazardous wastes; and/or (iii) impose obligations to investigate and remediate contamination.

The risk of contamination of air, soil and water at the electric businesses primarily relates to: (i) the transportation, handling, storage and combustion of fuel; (ii) the use of petroleum-based products, mainly transformer and lubricating oil; (iii) the management and disposal of coal combustion residuals and other wastes; and (iv) accidents resulting in hazardous release at or from coal mines that supply generating facilities. Contamination risks at the gas businesses primarily relate to gas and propane leaks and other accidents involving these substances. The key environmental risks for hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and dam failures.

Liabilities relating to contamination investigation and remediation, and claims for personal injury or property damage, may arise at many locations, including formerly and currently owned/operated properties and waste treatment or disposal sites, and regardless of whether such contamination was caused by the business at the time it owned the property or whether it resulted from non-compliance with applicable environmental laws. Under some environmental laws, such liabilities may be joint and several, meaning that a party can be held responsible for more than its share of the liability involved or even the entire liability. These liabilities could lead to litigation and administrative proceedings that could result in substantial monetary judgments for clean-up costs, damages, fines and/or penalties. To the extent not fully covered by insurance, these costs could have a Material Adverse Effect.

The Corporation's businesses have incurred substantial expenses for environmental compliance, and they anticipate continuing to do so in the future. In particular, the management of GHG emissions is a major concern due to new and emerging federal, state and provincial GHG laws, regulations and guidelines.

The Corporation's businesses continue to develop compliance strategies and assess the impact of emerging legislative changes, but significant uncertainties remain. Increased compliance costs or additional operating restrictions from revised or additional regulation could have a Material Adverse Effect.

Some coal-fired generation facilities utilized by UNS Energy have closed before the end of their useful lives due to economic conditions and/or recent or expected changes in environmental regulations, including those relating to GHG emissions. Early closures have necessitated regulatory relief to recover any remaining net book values and decommissioning costs, and potential accelerated depreciation could cause rate pressure. Significant unrecovered costs or rate pressures could have a Material Adverse Effect.

Insurance
Insurance is maintained with reputable industry insurers for property damage, potential liabilities and business interruption for coverage considered appropriate and in accordance with industry practice.

A significant portion of transmission and distribution assets is uninsured, as is customary in North America, as the cost is prohibitive. Insurance is subject to coverage limits and deductibles as well as time-sensitive claims discovery and reporting provisions. There is no assurance that: (i) the amounts and types of actual damage, liabilities or business interruption will be fully covered; (ii) regulatory relief would be obtained for coverage shortfalls; (iii) adequate insurance at reasonable rates will continue to be available; or (iv) insurers will fulfill their obligations. Significant actual shortfalls could have a Material Adverse Effect.

Required Approvals
The acquisition, ownership and operation of electric and gas businesses require numerous licences, permits, agreements, orders, certificates and other approvals from various levels of government, regulators, government agencies and/or third parties. There is no assurance that: (i) all of these will be obtained, continuously maintained or renewed without delay; and (ii) the terms and conditions thereof will be fully complied with at all times and will not change in a material adverse manner. Significant failures in these regards could prevent the operation of the businesses and have a Material Adverse Effect.

Reputation, Relationships and Stakeholder Activism
The Corporation’s operations and growth prospects require strong relationships with key stakeholders, including governments and agencies, Indigenous communities, landowners, and environmental organizations. Inadequately managing expectations and issues important to stakeholders, including those arising during construction, could affect the Corporation’s reputation as well as have a significant impact on its operations and infrastructure development.

Additionally, external stakeholders are increasingly challenging utilities regarding climate change, sustainability, diversity, returns including ROEs, executive compensation and other matters. Public opposition to larger infrastructure projects is becoming increasingly common, which can challenge capital plans and resultant organic growth. While the Corporation actively monitors such activism and is committed to developing stronger relationships with its external stakeholders, failure to effectively maintain or respond to stakeholder activism could have a Material Adverse Effect.

Indigenous Peoples' Land Claims
The Corporation's British Columbia utilities provide service to customers on Indigenous Peoples' lands and maintain facilities on lands that are subject to Indigenous Peoples' land claims. A treaty negotiation process involving Indigenous Peoples and the Governments of British Columbia and Canada is underway, but the basis for potential settlements is unclear and not all Indigenous Peoples are participating in the process. To date, the policy of the Government of British Columbia has been to structure settlements without prejudicing existing third-party rights. However, there is no assurance that the settlement process will not have a Material Adverse Effect.

FortisAlberta has distribution assets on Indigenous Peoples' lands in Alberta with access permits held by TransAlta Utilities Corporation. To acquire these permits, FortisAlberta requires approval from First Nations and Crown-Indigenous Relations and Northern Affairs Canada. FortisAlberta may be unable to obtain such approvals or negotiate land-use agreements with reasonable terms. Significant failures in these regards could have a Material Adverse Effect.

Labour Relations
Most of the Corporation's utilities employ members of labour unions or associations under collective bargaining agreements. Fortis considers its labour relationships to be satisfactory but there is no assurance that this will continue or that existing collective bargaining agreements will be renewed on reasonable terms without work disruption or other job action. Significant failures in these regards could cause service interruptions and/or labour cost increases for which the regulator disallows full recovery in rates, and could have a Material Adverse Effect.

Legal, Administrative and Other Proceedings
These proceedings arise in the ordinary course of business and may include environmental claims, employment-related claims, securities-based litigation, contractual disputes, personal injury or property damage claims, actions by regulatory or tax authorities, and other matters. Unfavourable outcomes such as judgments or settlements for monetary or other damages, injunctions, denial or revocation of permits, reputational harm, and other results could have a Material Adverse Effect.

ACCOUNTING MATTERS

New Accounting Policies
Leases
Effective January 1, 2019, the Corporation adopted ASU No. 2016-02, *Leases*, that requires lessees to recognize a right-of-use asset and lease liability for all leases with a lease term greater than 12 months, along with additional disclosures.

At lease inception, the right-of-use asset and liability are both measured at the present value of future lease payments, excluding variable payments that are based on usage or performance. Future lease payments include both lease components (e.g., rent, real estate taxes and insurance costs) and non-lease components (e.g., common area maintenance costs), which Fortis accounts for as a single lease component. The present value is calculated using the rate implicit in the lease or a lease-specific secured interest rate based on the remaining lease term. Renewal options are included in the lease term when it is reasonably certain that the option will be exercised.

Finance leases are depreciated over the lease term, except where: (i) ownership of the asset is transferred at the end of the lease term, in which case depreciation is over the estimated service life of the underlying asset; and (ii) the regulator has approved a different recovery methodology for rate-setting purposes, in which case the timing of the expense recognition will conform to the regulator's requirements.

Fortis applied the transition provisions of the new standard as of the adoption date and did not retrospectively adjust prior periods in accordance with the modified retrospective approach. Fortis elected a package of implementation options, referred to as practical expedients, that allowed it to not reassess: (i) whether existing contracts, including land easements, are or contain a lease; (ii) the classification of existing leases; or (iii) the initial direct costs for existing leases. Fortis also utilized the hindsight practical expedient to determine the lease term. Upon adoption, Fortis did not identify or record an adjustment to the opening balance of retained earnings, and there was no impact on net earnings or cash flows.

Hedging
Effective January 1, 2019, the Corporation adopted ASU No. 2017-12, *Targeted Improvements to Accounting for Hedging Activities,* which better aligns risk management activities and financial reporting for hedging relationships through changes to designation, measurement, presentation and disclosure guidance. Adoption did not have a material impact on the 2019 Annual Financial Statements.

Fair Value Measurement Disclosures
Effective January 1, 2019, the Corporation adopted ASU No. 2018-13, *Changes to the Disclosure Requirements for Fair Value Measurement*, which improves the effectiveness of financial statement note disclosures by clarifying what is required and important to users of the financial statements. The adoption of this ASU removed the following disclosures for all periods presented: (i) the amount of, and reasons for, transfers between level 1 and level 2 of the fair value hierarchy; (ii) the policy for the timing of transfers between levels; and (iii) the valuation processes for level 3 fair value measurements.

Pensions and Other Post-Retirement Plan Disclosures
Effective December 31, 2019, the Corporation early adopted, on a retrospective basis, ASU No. 2018-14, *Changes to the Disclosure Requirements for Defined Benefit Plans*, which modifies the disclosure requirements for employers with defined pension or other post-retirement plans and clarifies disclosure requirements. In particular, it removed the following disclosures: (i) the amounts in accumulated other comprehensive income expected to be recognized as components of net period benefit costs over the next fiscal period; and (ii) the effects of a one-percentage-point change on the assumed health care costs and the change in rates on service cost, interest cost and the benefit obligation for post-retirement health care benefits.

Future Accounting Pronouncements

Income Taxes

ASU No. 2019-12, *Simplifying the Accounting for Income Taxes*, issued in December 2019, is effective for Fortis January 1, 2021, with early adoption permitted. Principally, it improves consistent application of, and clarifies, existing income tax guidance. Fortis is assessing the impact that adoption will have on its consolidated financial statements.

Critical Accounting Estimates

General

The preparation of the 2019 Annual Financial Statements required management to make estimates and judgments that affect the reported amounts of, and disclosures related to, assets, liabilities, revenues, expenses, gains, losses and contingencies. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time they are made, with any adjustments recognized in the period they become known. Actual results may differ significantly from these estimates.

Regulatory Assets and Liabilities

As at December 31, 2019, Fortis recognized regulatory assets of $3.4 billion (December 31, 2018 - $3.1 billion) and regulatory liabilities of $3.4 billion (December 31, 2018 - $3.6 billion).

Regulatory assets represent future revenues and/or receivables associated with incurred costs that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent: (i) future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process; or (ii) an obligation to provide future service that customers have paid for in advance.

The recognition of regulatory assets and liabilities and the period(s) of settlement are often estimates based on past, existing or expected regulatory orders in relation to the nature of the underlying amounts and are subject to regulatory approval. Historically, actual settlement amounts and periods have generally not differed materially from those estimated, but there is no assurance that this will always be the case. Differences arising from the regulator's orders would be recognized in accordance with those orders, whereby any amounts disallowed would be immediately recognized in earnings with the remainder recognized in earnings in accordance with their inclusion in customer rates.

Employee Future Benefits

Key Estimates and Assumptions	**Defined Benefit Pension Plans**		**OPEB Plans**	
Years Ended December 31	**2019**	2018	**2019**	2018
Funded status [1] *($ millions)*				
Benefit obligation [2]	**(3,632)**	(3,207)	**(712)**	(655)
Plan assets	**3,208**	2,830	**343**	293
	(424)	(377)	**(369)**	(362)
Net benefit cost [2] *($ millions)*	**65**	83	**28**	34
Key assumptions: *(weighted average %)*				
Discount rate [3]				
During the year	**4.05**	3.56	**4.10**	3.57
As at December 31	**3.20**	4.07	**3.25**	4.13
Expected long-term rate of return on plan assets [4]	**5.78**	5.80	**5.50**	5.48
Rate of compensation increase	**3.33**	3.35	**—**	—
Health care cost trend increase rate [5]	**—**	—	**4.62**	4.61

(1) *Periodic actuarial valuations determine funding contributions for the pension plans and US OPEB plans, while Canadian OPEB plans are unfunded*

(2) *Actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation, average remaining service life of employees, mortality rates and, for OPEB plans, expected health care costs*

(3) *Reflects market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments*

(4) *Developed using best estimates of expected returns, volatilities and correlations for each class of asset. Estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.*

(5) *Actuarially determined, the projected 2020 rate is 6.15% and is assumed to decrease over the next 12 years to the ultimate rate of 4.62% in 2031 and thereafter.*

Sensitivity Analysis	**Rate of Return - 1% change**		**Discount Rate - 1% change**		**Health Care Cost Trend Rate - 1% change**	
Year ended December 31, 2019 *($ millions)*	**Increase**	**Decrease**	**Increase**	**Decrease**	**Increase**	**Decrease**
Defined benefit pension plans						
Net benefit cost	**(25)**	**23**	**(29)**	**55**	**n/a**	**n/a**
Projected benefit obligation	**25**	**(80)**	**(482)**	**612**	**n/a**	**n/a**
OPEB plans						
Net benefit cost	**(3)**	**3**	**(7)**	**10**	**24**	**(18)**
Accumulated benefit obligation	**n/a**	**n/a**	**(100)**	**128**	**104**	**(83)**

At the regulated utilities, changes in net benefit cost are generally expected to be reflected in customer rates, subject to regulatory lag and forecast risk at certain utilities.

At FortisAlberta, cash contributions are expensed and reflected in customer rates with any difference between the cash contributions and the net benefit cost deferred as a regulatory asset/liability. ITC, Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations between actual net pension cost and that forecast and reflected in customer rates. There is no assurance that these deferral mechanisms will continue in the future.

Depreciation and Amortization
As at December 31, 2019, Fortis recognized property, plant and equipment and intangible assets of $35.2 billion (December 31, 2018 - $34.0 billion) representing 66% of total assets (December 31, 2018 - 64%). Depreciation and amortization totalled $1.4 billion for 2019 (2018 - $1.2 billion).

Depreciation and amortization reflect the estimated useful lives of the underlying assets, which considers historical experience, manufacturers' ratings and specifications, the past and expected future pattern and nature of usage, and other factors.

At the regulated utilities, depreciation rates require regulatory approval and include a provision for estimated future asset removal costs not identified as a legal obligation. Estimates primarily reflect historical experience and expected cost trends. The provision is recognized as a long-term regulatory liability against which actual removal costs are netted when incurred. As at December 31, 2019, this regulatory liability was $1.2 billion (December 31, 2018 - $1.2 billion).

Depreciation rates at the regulated utilities are typically determined through periodic depreciation studies performed by external experts. Where actual experience differs from previous estimates, resultant differences are generally reflected in future depreciation rates and thereby recovered or refunded through customer rates in the manner prescribed by the regulator.

Goodwill Impairment
As at December 31, 2019, Fortis recognized goodwill of $12.0 billion (December 31, 2018 - $12.5 billion), representing 22% of total assets (December 31, 2018 - 24%).

Goodwill at each of the Corporation's 11 reporting units is tested for impairment annually and whenever an event or change in circumstances indicates that fair value may be below carrying value. If so determined, goodwill is written down to estimated fair value and an impairment loss is recognized.

The Corporation performs a qualitative assessment for certain reporting units and if it is determined that it is not likely that fair value is less than carrying value then a quantitative estimate of fair value is not required. Otherwise, the primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections are discounted using an enterprise value method. Underlying estimates and assumptions, with varying degrees of uncertainty, include the amount and timing of expected future cash flows, growth rates, and discount rates. A secondary valuation, the market approach along with a reconciliation of the total estimated fair value of all the reporting units to the Corporation's market capitalization, is also performed and evaluated.

The recognition of impairment losses could have a Material Adverse Effect. Such losses are not recoverable in regulated utility rates. To the extent impairment losses signal lower expected future cash flows to support interest payments on unregulated holding company debt and dividends on common shares, they could adversely affect the future cost of such capital, expressed as higher interest rates on such debt, which is not recoverable in regulated utility rates, and lower common share market prices.

Income Tax
As at December 31, 2019, deferred income tax liabilities, current income tax receivable included in accounts receivable, deferred income taxes included in regulatory assets, and deferred income taxes included in regulatory liabilities totalled $3.0 billion, $35 million, $1.6 billion and $1.4 billion, respectively (December 31, 2018 - $2.7 billion, $91 million, $1.5 billion and $1.6 billion, respectively). Income tax expense was $289 million in 2019 (2018 - $165 million).

Current income taxes reflect the estimated taxes payable/receivable in the current year based on enacted tax rates and laws, and the estimated proportion of taxable earnings/loss attributable to various jurisdictions.

Deferred income tax assets/liabilities reflect temporary differences between the tax and accounting basis of assets/liabilities. A deferred income tax asset or liability is determined for each temporary difference based on enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. To the extent future tax recovery is not assessed as "more likely than not", a valuation allowance is recognized in earnings when created or adjusted.

At the regulated utilities, differences between the tax expense/recovery normally recognized under US GAAP and that reflected in customer rates, which is expected to be recovered from/refunded to customers in future rates, are recognized as regulatory assets/liabilities. These regulatory assets/liabilities are subsequently amortized to earnings in accordance with their inclusion in customer rates pursuant to the regulator's orders. Otherwise, changes in expectations and resultant estimates arising from changes in tax rates, tax laws, jurisdictional earnings allocations and other factors are recognized in earnings upon occurrence.

Derivatives
The fair values of derivatives are based on estimates that cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting future earnings or cash flows. See "Financial Instruments - Derivatives" below.

Contingencies
The Corporation and its subsidiaries are subject to various legal proceedings and claims arising in the ordinary course of business, including those generally described under "Business Risks - Indigenous Peoples' Land Claims" on page 32, for which no amounts have been accrued because the outcomes currently cannot be reasonably determined. Further information is provided in Note 29 in the 2019 Annual Financial Statements.

While Fortis currently believes that these matters are unlikely to have a Material Adverse Effect, there is no assurance that this will be the case.

FINANCIAL INSTRUMENTS

LONG-TERM DEBT AND OTHER

As at December 31, 2019, the carrying value of long-term debt, including the current portion, was $22.3 billion (December 31, 2018 - $24.2 billion) compared to an estimated fair value of $25.3 billion (December 31, 2018 - $25.1 billion). Since Fortis does not intend to settle long-term debt prior to maturity, the excess of fair value over carrying value does not represent an actual liability.

The consolidated carrying value of the remaining financial instruments, other than derivatives, approximates fair value, reflecting their short-term maturity, normal trade credit terms and/or nature.

DERIVATIVES

Fortis generally limits derivative usage to those qualifying as accounting, economic or cash flow hedges, or those that are otherwise approved for regulatory recovery. Derivatives are recorded at fair value, with certain exceptions, including those derivatives that qualify for the normal purchase and normal sale exception.

Energy contracts subject to regulatory deferral
UNS Energy holds electricity power purchase contracts, customer supply contracts and gas swap contracts to reduce its exposure to energy price risk. Fair values are measured primarily under the market approach using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses.

Central Hudson holds swap contracts for electricity and natural gas to minimize price volatility by fixing the effective purchase price. Fair values are measured using forward pricing provided by independent third-party information.

FortisBC Energy holds gas supply contracts and commodity swaps to fix the effective purchase price of natural gas. Fair values reflect the present value of future cash flows based on published market prices and forward natural gas curves.

Unrealized gains/losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset/liability for recovery from/refund to customers in future rates, as permitted by the regulators. As at December 31, 2019, unrealized losses of $119 million (December 31, 2018 - $57 million) were recognized as regulatory assets and unrealized gains of $2 million (December 31, 2018 - $9 million) were recognized as regulatory liabilities.

Energy contracts not subject to regulatory deferral
UNS Energy holds wholesale trading contracts to fix power prices and realize potential margin, of which 10% of any realized gains is shared with customers through rate stabilization accounts. Fair values are measured using a market approach utilizing independent third-party information, where possible.

Aitken Creek holds gas swap contracts to manage its exposure to changes in natural gas prices, capture natural gas price spreads, and manage the financial risk posed by physical transactions. Fair values are measured using forward pricing from published market sources.

Unrealized gains/losses associated with changes in the fair value of these energy contracts are recognized in revenue. During 2019 unrealized losses of $16 million (2018 - unrealized losses of $12 million) were recognized in revenue.

Total return swaps
The Corporation holds total return swaps to manage the cash flow risk associated with forecasted future cash settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $111 million and terms of one to three years expiring in January 2020, 2021 and 2022. Fair values are measured using an income valuation approach based on forward pricing curves. During 2019 unrealized gains of $11 million (2018 - unrealized gains of less than $1 million) were recognized in other income, net.

Foreign exchange contracts
The Corporation holds US dollar foreign exchange contracts to help mitigate exposure to volatility of foreign exchange rates. The contracts expire in 2020 and have a combined notional amount of $166 million. Fair values are measured using independent third-party information. During 2019 unrealized gains of $11 million (2018 - unrealized losses of $11 million) were recognized in other income, net.

Interest rate swaps
During 2019 ITC entered into forward-starting interest rate swaps to manage the interest rate risk associated with the refinancing of long-term debt due in June 2021. The swaps have a combined notional value of $260 million and five-year terms with a mandatory early termination provision. The swaps will be terminated no later than the effective date of November 2020. Fair value was measured using a discounted cash flow method based on LIBOR rates. Unrealized gains and losses associated with changes in fair value are recognized in other comprehensive income, will be reclassified to earnings as a component of interest expense over the life of the debt, and were not material for 2019.

Other investments
ITC, UNS Energy and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees. These investments consist of mutual funds and money market accounts, which are recorded at fair value based on quoted market prices in active markets. Gains/losses on these funds are recognized in other income, net and were not material for 2019 and 2018.

Derivative Fair Values ($ millions)	**Level 1** [1]	**Level 2** [1]	**Level 3** [1]	**Total**
As at December 31, 2019				
Assets [2]				
Energy contracts subject to regulatory deferral	**—**	**22**	**—**	**22**
Energy contracts not subject to regulatory deferral	**—**	**8**	**—**	**8**
Foreign exchange contracts, interest rate and total return swaps	**14**	**4**	**—**	**18**
Other investments	**121**	**—**	**—**	**121**
	135	**34**	**—**	**169**
Liabilities [3]				
Energy contracts subject to regulatory deferral	**(1)**	**(138)**	**—**	**(139)**
Energy contracts not subject to regulatory deferral	**—**	**(12)**	**—**	**(12)**
	(1)	**(150)**	**—**	**(151)**
As at December 31, 2018				
Assets [2]				
Energy contracts subject to regulatory deferral	—	33	8	41
Energy contracts not subject to regulatory deferral	—	13	3	16
Other investments	155	—	—	155
	155	46	11	212
Liabilities [3]				
Energy contracts subject to regulatory deferral	—	(86)	(3)	(89)
Energy contracts not subject to regulatory deferral	—	(1)	—	(1)
Foreign exchange contracts, interest rate and total return swaps	(8)	(1)	—	(9)
	(8)	(88)	(3)	(99)

(1) *Under the hierarchy, fair value is determined using: (i) level 1 - unadjusted quoted prices in active markets; (ii) level 2 - other pricing inputs directly or indirectly observable in the marketplace; and (iii) level 3 - unobservable inputs, used when observable inputs are not available. Classifications reflect the lowest level of input that is significant to the measurement. At December 31, 2019, all level 3 assets and liabilities transferred to level 2 because observable market data became available.*

(2) *Current portion is included in accounts receivable and other current assets, with the remainder included in other assets.*

(3) *Current portion is included in accounts payable and other current liabilities, with the remainder included in other liabilities.*

Derivative Volumes [1] As at December 31	**2019**	2018
Energy contracts subject to regulatory deferral		
Electricity swap contracts *(GWh)*	**628**	774
Electricity power purchase contracts *(GWh)*	**3,198**	651
Gas swap contracts *(PJ)*	**168**	203
Gas supply contract premiums *(PJ)*	**241**	266
Energy contracts not subject to regulatory deferral		
Wholesale trading contracts *(GWh)*	**1,855**	1,440
Gas swap contracts *(PJ)*	**43**	37

(1) *Energy contracts settle on various dates through 2029.*

SELECTED ANNUAL FINANCIAL INFORMATION

Years ended December 31 *($ millions, except as indicated)*	**2019**	2018	2017
Revenue	**8,783**	8,390	8,301
Net earnings	**1,852**	1,286	1,125
Common Equity Earnings	**1,655**	1,100	963
EPS: *($)*			
Basic	**3.79**	2.59	2.32
Diluted	**3.78**	2.59	2.31
Total assets	**53,404**	53,051	47,822
Long-term debt (excluding current portion)	**21,501**	23,159	20,691
Dividends declared: *($)*			
Per common share	**1.855**	1.750	1.650
Per first preference share:			
Series F	**1.2250**	1.2250	1.2250
Series G [(1)]	**1.0983**	1.0345	0.9708
Series H	**0.6250**	0.6250	0.6250
Series I [(2)]	**0.7771**	0.7116	0.5262
Series J	**1.1875**	1.1875	1.1875
Series K [(3)]	**0.9821**	1.0000	1.0000
Series M [(4)]	**1.0135**	1.0250	1.0250

(1) *The annual dividend per share was reset from $0.9708 to $1.0983 for the five-year period from September 1, 2018 up to but excluding September 1, 2023.*

(2) *Floating quarterly dividend rate is reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus the applicable reset dividend yield.*

(3) *The annual dividend per share was reset from $1.0000 to $0.9823 for the five-year period from March 1, 2019 up to but excluding March 1, 2024.*

(4) *The annual dividend per share was reset from $1.0250 to $0.9783 for the five-year period from December 1, 2019 up to but excluding December 1, 2024.*

2019/2018

For a discussion of the changes in revenue, net earnings, Common Equity Earnings, EPS, total assets and long-term debt refer to "Performance at a Glance" on page 3, "Operating Results" on page 7, and "Financial Position" on page 15.

2018/2017

The 2018/2017 increase in revenue reflects: (i) higher wholesale electricity sales at UNS Energy driven by an increase in system capacity; and (ii) the flow through in 2018 customer rates of higher overall energy supply costs. The increase was partially offset by: (i) the recovery of lower income tax expense due to US tax reform; (ii) mark-to-market accounting adjustments for natural gas derivatives at Aitken Creek; and (iii) a change in presentation of certain revenues to a net basis upon implementation of ASC 606, *Revenue from Contracts with Customers*, in 2018.

The 2018/2017 increase in earnings primarily reflects growth at both the regulated and non-regulated businesses, as well as lower income tax expense, partially offset by one-time favourable adjustments recognized in 2017. Earnings in 2018 were also tempered by the ongoing impact of US tax reform and a lower ROE incentive adder at ITC effective April 2018.

The 2018/2017 increase in EPS reflects the above-noted earnings increases, partially offset by a 9.2 million increase in the weighted average number of common shares outstanding associated with the Corporation's DRIP.

The 2018/2017 increase in total assets was due to the impact of 2018 capital expenditures and foreign exchange on the translation of US dollar-denominated assets.

FOURTH QUARTER RESULTS

Sales Fourth quarters ended December 31	**2019**	2018	Variance
Regulated utilities			
UNS Energy			
Retail Electricity *(GWh)*	**2,223**	2,225	(2)
Wholesale Electricity *(GWh)*	**1,814**	2,526	(712)
Gas *(PJ)*	**5**	5	—
Central Hudson			
Electricity *(GWh)*	**1,188**	1,250	(62)
Gas *(PJ)*	**6**	7	(1)
FortisBC Energy *(PJ)*	**71**	63	8
FortisAlberta *(GWh)*	**4,279**	4,343	(64)
FortisBC Electric *(GWh)*	**888**	839	49
Other Electric *(GWh)*	**2,427**	2,450	(23)
Non-regulated - Energy Infrastructure *(GWh)*	**14**	85	(71)

The decrease in wholesale electricity sales was due primarily to a decrease in system capacity at Gila River Unit 2 resulting from an outage. The increase in gas volumes at FortisBC Energy was due to higher average consumption by residential and commercial customers due to colder temperatures that increased heating load and higher consumption by transportation customers.

Revenue and Common Equity Earnings Fourth quarters ended December 31	Revenue			Common Equity Earnings		
($ millions, except as indicated)	**2019**	2018	Variance	**2019**	2018	Variance
Regulated utilities						
ITC	**500**	390	110	**171**	92	79
UNS Energy	**510**	541	(31)	**38**	27	11
Central Hudson	**226**	234	(8)	**30**	24	6
FortisBC Energy	**428**	371	57	**77**	72	5
FortisAlberta	**150**	140	10	**33**	22	11
FortisBC Electric	**112**	111	1	**12**	13	(1)
Other Electric	**381**	372	9	**22**	22	—
Non-regulated						
Energy Infrastructure	**19**	50	(31)	**6**	22	(16)
Corporate and Other	**—**	—	—	**(43)**	(33)	(10)
Inter-segment eliminations	**—**	(3)	3	**—**	—	—
Total	**2,326**	2,206	120	**346**	261	85
Weighted average number of common shares outstanding *(millions)*				**447.1**	427.5	19.6
Basic EPS *($)*				**0.77**	0.61	0.16

The increase in revenue was driven by the $91 million favourable adjustment to revenue at ITC associated with the November 2019 FERC Order (see "Regulatory Highlights" on page 13) and higher revenue at FortisBC Energy due to overall higher flow-through costs. The increase was partially offset by lower revenue at UNS Energy due to lower short-term wholesale sales and lower revenue in the Energy Infrastructure segment due to the disposition of the Waneta Expansion in April 2019 (see "Significant Items" on page 3) and lower hydroelectric production in Belize.

The increase in Common Equity Earnings was due primarily to the November 2019 FERC Order at ITC, along with Rate Base growth at the regulated utilities.

The increase in basic EPS reflects higher Common Equity Earnings, partially offset by a 19.6 million increase in the weighted average number of common shares outstanding associated with the Corporation's common equity offering (see "Significant Items" on page 3), DRIP and ATM Program.

Cash Flows Fourth quarters ended December 31 *($ millions)*	**2019**	2018	Variance
Cash, beginning of period	**228**	195	33
Cash provided by (used in):			
Operating activities	**634**	537	97
Investing activities	**(1,104)**	(999)	(105)
Financing activities	**627**	598	29
Foreign exchange	**(15)**	16	(31)
Cash associated with assets held for sale	**—**	(15)	15
Cash, end of period	**370**	332	38

Operating Activities
The variance was due to higher cash earnings at the regulated subsidiaries, led by ITC, partially offset by unfavourable changes in working capital due primarily to timing differences.

Investing Activities
The variance reflects higher capital spending, mainly at UNS Energy, in accordance with the Corporation's capital plan.

Financing Activities
The variance reflects the issuance of common shares and redemption of Corporate debt (see "Cash Flow Summary" on page 18).

SUMMARY OF QUARTERLY RESULTS

Quarter Ended	**Revenue** *($ millions)*	**Common Equity Earnings** *($ millions)*	**Basic EPS** *($)*	**Diluted EPS** *($)*
December 31, 2019	**2,326**	**346**	**0.77**	**0.77**
September 30, 2019	**2,051**	**278**	**0.64**	**0.63**
June 30, 2019	**1,970**	**720**	**1.66**	**1.66**
March 31, 2019	**2,436**	**311**	**0.72**	**0.72**
December 31, 2018	2,206	261	0.61	0.61
September 30, 2018	2,040	276	0.65	0.65
June 30, 2018	1,947	240	0.57	0.57
March 31, 2018	2,197	323	0.77	0.76

Generally, within each calendar year, quarterly results fluctuate primarily in accordance with seasonality. Given the diversified nature of the Corporation's subsidiaries, seasonality varies. Most of the annual earnings of the gas utilities are realized in the first and fourth quarters due to space-heating requirements. Earnings for the electric distribution utilities in the US are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment.

Generally, from one calendar year to the next, quarterly results reflect: (i) continued organic growth driven by the Corporation's capital plan; (ii) acquisitions and dispositions; (iii) any significant temperature fluctuations from seasonal norms; (iv) the timing and significance of any regulatory decisions; (v) for revenue, the flow through in customer rates of commodity costs; and (vi) for EPS, increases in the weighted average number of common shares outstanding.

December 2019 / December 2018
See "Fourth Quarter Results" on page 41.

September 2019 / September 2018
Common Equity Earnings increased by $2 million and basic EPS decreased by $0.01, due mainly to Rate Base growth at the regulated utilities, led by ITC, tempered by: (i) the unfavourable impact of the mark-to-market accounting of natural gas derivatives at Aitken Creek; (ii) lower hydroelectric production in Belize; and (iii) for EPS, an 11.8 million increase in the weighted average number of common shares outstanding due to the ATM Program and DRIP.

June 2019 / June 2018
Common Equity Earnings increased by $480 million and basic EPS increased by $1.09, due mainly to: (i) a $484 million gain on the disposition of the Waneta Expansion; (ii) the favourable impact of the mark-to-market accounting of natural gas derivatives at Aitken Creek; (iii) Rate Base growth at the regulated utilities, led by ITC; and (iv) favourable foreign exchange of $7 million. The increase was tempered by: (i) lower retail sales, driven by weather, and higher depreciation and interest expense at UNS Energy; (ii) lower earnings contribution from the Energy Infrastructure segment due to lower hydroelectric production in Belize; (iii) lower realized margins at Aitken Creek; and (iv) for EPS, a 9.3 million increase in the weighted average number of common shares outstanding due to the ATM Program and DRIP.

March 2019 / March 2018
Common Equity Earnings decreased by $12 million and basic EPS decreased by $0.05, due mainly to: (i) a favourable $30 million remeasurement of deferred income tax liabilities in 2018 resulting from an election to file a consolidated state income tax return, which offset earnings growth in 2019. Earnings growth was driven by: (i) strong performance at the regulated utilities due primarily to Rate Base growth; (ii) increased earnings at Central Hudson associated with its rate order effective July 1, 2018; (iii) higher electricity and gas sales at UNS Energy due largely to weather; and (iv) favourable foreign exchange of $9 million. The increase was tempered by: (i) lower earnings contribution from the Energy Infrastructure segment due to lower realized margins and higher unrealized losses on the mark-to-market accounting of natural gas derivatives at Aitken Creek, along with lower hydroelectric production in Belize; (ii) a lower ROE incentive adder at ITC; and (iii) for EPS, a 7.5 million increase in the weighted average number of common shares outstanding due mainly to the DRIP.

RELATED-PARTY TRANSACTIONS

Related-party transactions are in the normal course of operations and are measured at the amount of consideration agreed to by the related parties. There were no material related-party transactions in 2019 or 2018. Inter-company balances, transactions and profit are eliminated on consolidation, except for certain inter-company transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. These related-party transactions include: (i) the lease of gas storage capacity and gas sales by Aitken Creek to FortisBC Energy; and (ii) the sale of capacity by the Waneta Expansion to FortisBC Electric up to the April 16, 2019 disposition of the Waneta Expansion. These transactions, which are not eliminated on consolidation, did not have a material impact on consolidated earnings, financial position or cash flows.

The Corporation periodically provides short-term financing to subsidiaries to support capital expenditures, acquisitions and seasonal working capital requirements. As at December 31, 2019, there were inter-segment loans outstanding of $279 million (December 31, 2018 - $nil), payable on demand with a weighted average interest rate of 2.48%. Total interest charged in 2019 was $2 million.

MANAGEMENT'S EVALUATION OF CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

DCP are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and US securities laws. As of December 31, 2019, an evaluation was carried out under the supervision of, and with the participation of, the Corporation's management, including the CEO and CFO, of the effectiveness of the Corporation's DCP, as defined in the applicable Canadian and United States securities laws. Based on that evaluation, the CEO and CFO concluded that such DCP are effective as of December 31, 2019.

Internal Control over Financial Reporting

ICFR is designed by, or under the supervision of, the Corporation's CEO and CFO and effected by the Corporation's 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 US GAAP. Because of its inherent limitations, ICFR may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Corporation's management, including the Corporation's CEO and CFO, assessed the effectiveness of the Corporation's ICFR as of December 31, 2019, based on the criteria set forth in *Internal Control - Integrated Framework (*2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that, as of December 31, 2019, the Corporation's ICFR was effective.

During the year ended December 31, 2019, there have been no changes in the Corporation's ICFR that have materially affected, or are reasonably likely to materially affect, the Corporation's ICFR.

OUTLOOK

Over the long term, Fortis is well positioned to enhance shareholder value through the execution of its capital plan, the balance and strength of its diversified portfolio of utility businesses, and growth opportunities within and proximate to its service territories.

The Corporation's $18.8 billion five-year capital plan is expected to increase Rate Base from $28.0 billion in 2019 to $34.5 billion by 2022 and $38.4 billion by 2024, translating into three- and five-year CAGRs of 7.2% and 6.5%, respectively. The five-year capital plan reflects the continuation of key industry trends including grid modernization and the delivery of cleaner energy. Beyond the base capital plan, Fortis continues to pursue additional energy infrastructure opportunities. Key opportunities not yet included in the five-year capital plan include: further expansion of LNG infrastructure in British Columbia; the fully permitted, cross-border, Lake Erie connector electric transmission project in Ontario; and the acceleration of cleaner energy goals in Arizona.

Fortis expects long-term growth in Rate Base to support continuing growth in earnings and dividends. Fortis is targeting average annual dividend growth of approximately 6% through 2024. This dividend guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at the Corporation's utilities, the successful execution of the five-year capital plan, and management's continued confidence in the strength of the Corporation's diversified portfolio of utilities and record of operational excellence.

FORWARD-LOOKING INFORMATION

Fortis includes forward-looking information in the MD&A within the meaning of applicable Canadian securities laws and forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995, (collectively referred to as "forward-looking information"). Forward-looking information reflects expectations of Fortis management regarding future growth, results of operations, performance, business prospects and opportunities. Wherever possible, words such as anticipates, believes, budgets, could, estimates, expects, forecasts, intends, may, might, plans, projects, schedule, should, target, will, would and the negative of these terms and other similar terminology or expressions have been used to identify the forward-looking information, which includes, without limitation: targeted average annual dividend growth through 2024; forecast capital expenditures for 2020 and the period 2020 through 2024, and potential funding sources for the capital plan; forecast Rate Base for 2020 and 2024; the expectation that Fortis will remain at the forefront of the industry by leveraging its strengths and partnerships; expected timing, outcome and impact of regulatory filings and decisions; expected or potential funding sources for operating expenses, interest costs and capital plans; the expectation that maintaining the targeted capital structure of the regulated operating subsidiaries will not have an impact on its ability to pay dividends in the foreseeable future; expected consolidated fixed-term debt maturities and repayments over the next five years; the expectation that the Corporation and its subsidiaries will continue to have access to long-term capital and will remain compliant with debt covenants throughout 2020; the nature, timing, benefits and expected costs of certain capital projects including the Multi-Value Regional Transmission Projects, Transmission Conversion Project, Southline Transmission Project, Oso Grande Wind Project, Transmission Integrity Management Capabilities Project, Inland Gas Upgrades Project, Wataynikaneyap Transmission Power Project and additional opportunities beyond the base plan, including the Lake Erie Connector Project; the expectation that the adoption of future accounting pronouncements will not have a material adverse impact; and the expectation that capital investment will support growth in earnings and dividends.

Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information, including, without limitation: reasonable regulatory decisions and the expectation of regulatory stability; the implementation of the five-year capital plan; no material capital project or financing cost overruns; sufficient human resources to deliver service and execute the capital plan; the realization of additional opportunities; the Board exercising its discretion to declare dividends, taking into account the financial performance and condition of the Corporation; no significant variability in interest rates; no significant operational disruptions or environmental liability or upset; the continued ability to maintain the performance of the electricity and gas systems; no severe and prolonged economic downturn; sufficient liquidity and capital resources; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas prices and electricity prices; the continued availability of natural gas, fuel, coal and electricity supply; continuation of power supply and capacity purchase contracts; no significant changes in government energy plans, environmental laws and regulations that could have a material negative impact; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; no significant changes in tax laws and the continued tax deferred treatment of earnings from the Corporation's foreign operations; continued maintenance of information technology infrastructure and no material breach of cybersecurity; continued favourable relations with Indigenous Peoples; and favourable labour relations.

Forward-looking information involves significant risks, uncertainties and assumptions. Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from those discussed or implied in the forward-looking information. These factors should be considered carefully and undue reliance should not be placed on the forward-looking information. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risks" in this MD&A and in other continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and the Securities and Exchange Commission. Key risk factors for 2020 include, but are not limited to: uncertainty regarding the outcome of regulatory proceedings at the Corporation's utilities; risks associated with climate change and physical risks; the impact of fluctuations in interest rates; the impact of weather variability and seasonality on heating and cooling loads, gas distribution volumes and hydroelectric generation; and risks associated with acquisitions and capital projects.

All forward-looking information herein is given as of February 12, 2020. Fortis disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

GLOSSARY

2019 Annual Financial Statements: *the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2019*

Actual Payout Ratio: *dividends per common share divided by basic EPS*

Adjusted Basic EPS: *Adjusted Common Equity Earnings divided by the basic weighted average number of common shares outstanding*

Adjusted Common Equity Earnings: *net earnings attributable to common equity shareholders adjusted as shown under "Non-US GAAP Financial Measures" on page 12*

Adjusted Payout Ratio: *dividends per common share divided by Adjusted Basic EPS as shown under "Non-US GAAP Financial Measures" on page 12*

AESO: *Alberta Electric System Operator*

AFUDC: *allowance for funds used during construction*

Aitken Creek: *Aitken Creek Gas Storage ULC, a direct 93.8%-owned subsidiary of FortisBC Holdings Inc.*

ALJ: *administrative law judge*

ASU: *Accounting Standards Update*

ATM Program: *at-the-market common equity program*

AUC: *Alberta Utilities Commission*

BCUC: *British Columbia Utilities Commission*

BECOL: *Belize Electric Company Limited, an indirect wholly owned subsidiary of Fortis*

Belize Electricity: *Belize Electricity Limited, in which Fortis indirectly holds a 33% equity interest*

CAGR(s): *compound average growth rate of a particular item. CAGR = $(EV/BV)^{1-N}$ -1, where: (i) EV is the ending value of the item; (ii) BV is the beginning value of the item; and (iii) N is the number of periods*

Caribbean Utilities: *Caribbean Utilities Company, Ltd., an indirect approximately 60%-owned (as at December 31, 2019) subsidiary of Fortis, together with its subsidiary*

Central Hudson: *CH Energy Group Inc., an indirect wholly owned subsidiary of Fortis, together with its subsidiaries, including Central Hudson Gas & Electric Corporation*

CEO: *Chief Executive Officer of Fortis*

CFO: *Chief Financial Officer of Fortis*

Common Equity Earnings: *net earnings attributable to common equity shareholders*

Corporation: *Fortis Inc.*

COS Regulation: *cost of service regulation*

CPCN: *Certificate of Public Convenience and Necessity*

DBRS Morningstar: *DBRS Limited*

DCP: *disclosure controls and procedures*

DRIP: *dividend reinvestment plan*

EPS: *earnings per common share*

ERM: *enterprise risk management*

FERC: *Federal Energy Regulatory Commission*

Fortis: *Fortis Inc.*

FortisAlberta: *FortisAlberta Inc., an indirect wholly owned subsidiary of Fortis*

FortisBC Electric: *FortisBC Inc., an indirect wholly owned subsidiary of Fortis, together with its subsidiaries*

FortisBC Energy: *FortisBC Energy Inc., an indirect wholly owned subsidiary of Fortis, together with its subsidiaries*

FortisOntario: *FortisOntario Inc., a direct wholly owned subsidiary of Fortis, together with its subsidiaries*

FortisTCI: *FortisTCI Limited, an indirect wholly owned subsidiary of Fortis, together with its subsidiary*

FX: *foreign exchange associated with the translation of US dollar-denominated amounts*

GHG: *greenhouse gas*

Gila River Unit 2: *UNS Energy's Gila River natural gas generation station unit 2*

GWh: *gigawatt hour(s)*

ICFR: *internal controls over financial reporting*

ITC: *ITC Investment Holdings Inc., an indirect 80.1%-owned subsidiary of Fortis, together with its subsidiaries, including International Transmission Company, Michigan Electric Transmission Company, LLC, ITC Midwest LLC, and ITC Great Plains, LLC*

ITC's MISO Subsidiaries: *International Transmission Company, Michigan Electric Transmission Company, LLC, and ITC Midwest LLC*

LIBOR: *London Interbank Offered Rate*

LNG: *liquefied natural gas*

kV: *kilovolt*

Major Capital Projects: *projects, other than ongoing maintenance projects, individually costing $200 million or more*

Maritime Electric: *Maritime Electric Company, Limited, an indirect wholly owned subsidiary of Fortis*

Material Adverse Effect: *a material adverse effect on the Corporation's business, results of operations, financial position or liquidity, on a consolidated basis*

MD&A: *the Corporation's management discussion and analysis for the year ended December 31, 2019*

MISO: *Midcontinent Independent System Operator, Inc.*

Moody's: *Moody's Investor Services, Inc.*

MW: *megawatt(s)*

Newfoundland Power: *Newfoundland Power Inc., a direct wholly owned subsidiary of Fortis*

NOI: *notice of inquiry*

Non-US GAAP Financial Measures: *financial measures that do not have a standardized meaning prescribed by US GAAP*

November 2019 FERC Order: *a FERC order issued in November 2019 that reduced the base ROE for ITC's MISO Subsidiaries*

NYSE: *New York Stock Exchange*

OEB: *Ontario Energy Board*

OPEB: *other post-employment benefits*

Operating Cash Flows: *cash from operating activities*

PBR: *performance-based rate-setting*

PJ: *petajoule(s)*

PPA: *power purchase agreement*

Q3 2019 MD&A: *interim management discussion and analysis for the three and nine months ended September 30, 2019*

Rate Base: *the stated value of property on which a regulated utility is permitted to earn a specified return in accordance with its regulatory construct*

ROA: *rate of return on Rate Base*

ROE: *rate of return on common equity*

S&P: *Standard & Poor's Financial Services LLC*

SEDAR: *Canadian System for Electronic Document Analysis and Retrieval*

TEP: *Tucson Electric Power Company, a direct wholly owned subsidiary of UNS Energy*

TSR: *total shareholder return, which is a measure of the return to common equity shareholders in the form of share price appreciation and dividends (assuming reinvestment) over a specified time period in relation to the share price at the beginning of the period*

TSX: *Toronto Stock Exchange*

UNS Energy: *UNS Energy Corporation, an indirect wholly owned subsidiary of Fortis, together with its subsidiaries, including TEP, UNS Electric, Inc. and UNS Gas, Inc.*

US: *United States of America*

US GAAP: *accounting principles generally accepted in the US*

Waneta Expansion: *Waneta Expansion hydroelectric generation facility, in which Fortis held a 51% controlling interest prior to April 2019*

Wataynikaneyap Partnership: *Wataynikaneyap Power Limited Partnership*

FORTIS INC.

Audited Consolidated Financial Statements
As at and for the years ended December 31, 2019 and 2018

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Management's Report on Internal Control over Financial Reporting

Management of Fortis Inc. and its subsidiaries (the "Corporation") is responsible for establishing and maintaining adequate internal control over financial reporting ("ICFR"). The Corporation's ICFR is designed by, or under the supervision of, the Corporation's President and Chief Executive Officer ("CEO") and Executive Vice President, Chief Financial Officer ("CFO") and effected by the Corporation's 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 accounting principles generally accepted in the United States of America. Because of its inherent limitations, ICFR may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Corporation's management, including its CEO and CFO, assessed the effectiveness of the Corporation's ICFR as of December 31, 2019, based on the criteria set forth in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that, as of December 31, 2019, the Corporation's ICFR was effective.

The Corporation's ICFR as of December 31, 2019 has been audited by Deloitte LLP, an Independent Registered Public Accounting Firm, which also audited the Corporation's consolidated financial statements for the year ended December 31, 2019. Deloitte LLP issued an unqualified opinion for both audits.

February 12, 2020

/s/ Barry V. Perry

Barry V. Perry
President and Chief Executive Officer, Fortis Inc.

/s/ Jocelyn H. Perry

Jocelyn H. Perry
Executive Vice President, Chief Financial Officer, Fortis Inc.

St. John's, Canada

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Fortis Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Fortis Inc. and subsidiaries (the "Corporation") as of December 31, 2019 and 2018, the related consolidated statements of earnings, comprehensive income, cash flows and changes in equity for each of the two years in the period ended December 31, 2019, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Corporation as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Corporation’s internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 12, 2020, expressed an unqualified opinion on the Corporation’s internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Corporation’s management. Our responsibility is to express an opinion on the Corporation’s financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Corporation in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Assessment for Impairment of Goodwill - Refer to Notes 3 and 13 to the financial statements

Critical Audit Matter Description

The Corporation assesses goodwill for impairment annually as well as whenever any event or other change indicates that the fair value of a reporting unit may be below its carrying value. Management has determined that there is no impairment based on its current annual assessment.

Management's assessment utilizes the income approach which is based on underlying estimates and assumptions with varying degrees of uncertainty. Those with the highest degree of subjectivity and impact are the assumed growth rates and discount rates. Auditing these estimates and assumptions required a high degree of audit judgment and effort, including the need to involve a fair value specialist.

How the Critical Audit Matter was Addressed in the Audit

Our audit procedures related to the growth rate and discount rate used by management to estimate the fair value of the reporting units included the following, among others:

- Evaluating the effectiveness of controls over the estimated fair value of the reporting units, including the review and approval of the growth rate and discount rate selected by management.
- Evaluating management's ability to accurately forecast the growth rate by:
    - Assessing the methodology used in management's determination of the growth rate and,
    - Comparing management's assumptions to historical data and available market trends.
- With the assistance of a fair value specialist, evaluating the reasonableness of the discount rate by:
    - Testing the source information underlying the determination of the discount rate and,
    - Developing a range of independent estimates and comparing those to the discount rate selected by management.

Impact of Rate Regulation on the Financial Statements - Refer to Notes 2, 3 and 9 to the Financial Statements

Critical Audit Matter Description

The Corporation's regulated utilities are subject to rate regulation and annual earnings oversight by various federal, state and provincial regulatory authorities who have jurisdiction in the United States and Canada. Rates and resultant earnings of the Corporation's regulated utilities are determined under cost of service regulation, with some using performance-based rate-setting mechanisms. The regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on asset value (ROA) or common shareholders' equity (ROE). Regulatory decisions can have an impact on the timely recovery of costs and the regulator-approved ROE and/or ROA. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment; regulatory assets and liabilities; operating revenues and expenses; income taxes; and depreciation expense.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the potential impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of recovery of costs incurred or a refund to customers through the rate-setting process. While the Corporation's regulated utilities have indicated they expect to recover costs from customers through regulated rates, there is a risk that the respective regulatory authority will not approve full recovery of the costs incurred and a reasonable ROE and/or ROA. Auditing these matters required especially subjective judgment and specialized knowledge of accounting for rate regulation due its inherent complexities across different jurisdictions.

How the Critical Audit Matter was Addressed in the Audit

Our audit procedures related to the likelihood of recovery of costs incurred or a refund to customers through the rate-setting process, included the following, among others:

- Evaluating the effectiveness of controls over the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- Assessing relevant regulatory orders, regulatory statutes and interpretations as well as procedural memorandums, utility and intervener filings, and other publicly available information to evaluate the likelihood of recovery in future rates or of a future reduction in rates and the ability to earn a reasonable ROA or ROE.

- For regulatory matters in progress, inspecting the regulated utilities' filings for any evidence that might contradict management's assertions. We obtained an analysis from management and letters from internal and external legal counsel, as appropriate, regarding cost recoveries or a future reduction in rates.
- Evaluating the Corporation's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

/s/ Deloitte LLP

Chartered Professional Accountants

St. John's, Canada
February 12, 2020

We have served as the Corporation's auditor since 2017.

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Fortis Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Fortis Inc. and subsidiaries (the "Corporation") as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as at and for the year ended December 31, 2019, of the Corporation and our report dated February 12, 2020, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Corporation's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Corporation in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte LLP
Chartered Professional Accountants

St. John's, Canada
February 12, 2020

FORTIS INC.
Consolidated Balance Sheets
As at December 31
(in millions of Canadian dollars)

		2019		2018
ASSETS				
Current assets				
Cash and cash equivalents	$	370	$	332
Accounts receivable and other current assets (Note 7)		1,297		1,357
Prepaid expenses		88		84
Inventories (Note 8)		394		398
Regulatory assets (Note 9)		425		324
Assets held for sale (Note 23)		—		766
Total current assets		2,574		3,261
Other assets (Note 10)		620		552
Regulatory assets (Note 9)		2,958		2,751
Property, plant and equipment, net (Note 11)		33,988		32,757
Intangible assets, net (Note 12)		1,260		1,200
Goodwill (Note 13)		12,004		12,530
Total assets	$	53,404	$	53,051
LIABILITIES AND EQUITY				
Current liabilities				
Short-term borrowings (Note 15)	$	512	$	60
Accounts payable and other current liabilities (Note 14)		2,378		2,289
Regulatory liabilities (Note 9)		572		656
Current installments of long-term debt (Note 15)		690		926
Current installments of finance leases (Note 16)		24		252
Liabilities associated with assets held for sale (Note 23)		—		69
Total current liabilities		4,176		4,252
Other liabilities (Note 17)		1,446		1,138
Regulatory liabilities (Note 9)		2,786		2,970
Deferred income taxes (Note 25)		2,969		2,686
Long-term debt (Note 15)		21,501		23,159
Finance leases (Note 16)		413		390
Total liabilities		33,291		34,595
Commitments and contingencies (Note 29)				
Equity				
Common shares (Note 18) [(1)]		13,645		11,889
Preference shares (Note 20)		1,623		1,623
Additional paid-in capital		11		11
Accumulated other comprehensive income (Note 21)		336		928
Retained earnings		2,916		2,082
Shareholders' equity		18,531		16,533
Non-controlling interests		1,582		1,923
Total equity		20,113		18,456
Total liabilities and equity	$	53,404	$	53,051

[(1)] *No par value. Unlimited authorized shares; 463.3 million and 428.5 million issued and outstanding as at December 31, 2019 and 2018, respectively*

Approved on Behalf of the Board

/s/ Douglas J. Haughey
Douglas J. Haughey, Director

/s/ Tracey C. Ball
Tracey C. Ball, Director

See accompanying Notes to Consolidated Financial Statements

FORTIS INC.
Consolidated Statements of Earnings
For the years ended December 31
(in millions of Canadian dollars, except per share amounts)

	2019	2018
Revenue (Note 6)	$ 8,783	$ 8,390
Expenses		
Energy supply costs	2,520	2,495
Operating expenses	2,452	2,287
Depreciation and amortization	1,350	1,243
Total expenses	6,322	6,025
Gain on disposition (Note 23)	577	—
Operating income	3,038	2,365
Other income, net (Note 24)	138	60
Finance charges	1,035	974
Earnings before income tax expense	2,141	1,451
Income tax expense (Note 25)	289	165
Net earnings	$ 1,852	$ 1,286
Net earnings attributable to:		
Non-controlling interests	$ 130	$ 120
Preference equity shareholders	67	66
Common equity shareholders	1,655	1,100
	$ 1,852	$ 1,286
Earnings per common share (Note 19)		
Basic	$ 3.79	$ 2.59
Diluted	$ 3.78	$ 2.59

See accompanying Notes to Consolidated Financial Statements

FORTIS INC.
Consolidated Statements of Comprehensive Income
For the years ended December 31
(in millions of Canadian dollars)

	2019	2018
Net earnings	$ 1,852	$ 1,286
Other comprehensive (loss) income		
Unrealized foreign currency translation (losses) gains, net of hedging activities and income tax (expense) recovery of $(13) million and $11 million, respectively	(660)	985
Other, net of income tax recovery (expense) of $5 million and $(2) million, respectively	(7)	6
	(667)	991
Comprehensive income	$ 1,185	$ 2,277
Comprehensive income attributable to:		
Non-controlling interests	$ 55	$ 244
Preference equity shareholders	67	66
Common equity shareholders	1,063	1,967
	$ 1,185	$ 2,277

See accompanying Notes to Consolidated Financial Statements

FORTIS INC.
Consolidated Statements of Cash Flows
For the years ended December 31
(in millions of Canadian dollars)

	2019	2018
Operating activities		
Net earnings	**$ 1,852**	$ 1,286
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation - property, plant and equipment	**1,199**	1,107
Amortization - intangible assets	**125**	106
Amortization - other	**26**	30
Deferred income tax expense (Note 25)	**247**	136
Equity component, allowance for funds used during construction (Note 24)	**(74)**	(64)
Gain on disposition (Note 23)	**(583)**	—
Other	**145**	92
Change in long-term regulatory assets and liabilities	**(106)**	13
Change in working capital (Note 27)	**(168)**	(102)
Cash from operating activities	**2,663**	2,604
Investing activities		
Capital expenditures - property, plant and equipment	**(3,499)**	(3,032)
Capital expenditures - intangible assets	**(221)**	(186)
Contributions in aid of construction	**102**	106
Proceeds on disposition (Note 23)	**995**	—
Other	**(145)**	(140)
Cash used in investing activities	**(2,768)**	(3,252)
Financing activities		
Proceeds from long-term debt, net of issuance costs (Note 15)	**937**	1,566
Repayments of long-term debt, net of extinguishment costs, and finance leases	**(1,676)**	(563)
Borrowings under committed credit facilities	**5,892**	5,666
Repayments under committed credit facilities	**(6,290)**	(5,523)
Net change in short-term borrowings	**472**	38
Issue of common shares, net of costs, and dividends reinvested (Note 18)	**1,442**	34
Dividends		
Common shares, net of dividends reinvested	**(494)**	(459)
Preference shares	**(67)**	(66)
Subsidiary dividends paid to non-controlling interests	**(73)**	(85)
Other	**11**	36
Cash from financing activities	**154**	644
Effect of exchange rate changes on cash and cash equivalents	**(26)**	24
Change in cash and cash equivalents	**23**	20
Cash and change in cash associated with assets held for sale	**15**	(15)
Cash and cash equivalents, beginning of year	**332**	327
Cash and cash equivalents, end of year	**$ 370**	$ 332

Supplementary Cash Flow Information (Note 27)

See accompanying Notes to Consolidated Financial Statements

FORTIS INC.

Consolidated Statements of Changes in Equity

For the years ended December 31, 2019 and 2018

(in millions of Canadian dollars, except share numbers)

	Common Shares (# millions)	Common Shares (Note 18)	Preference Shares (Note 20)	Additional Paid-In Capital	Accumulated Other Comprehensive Income (Loss) (Note 21)	Retained Earnings	Non-Controlling Interests	Total Equity
As at December 31, 2018	**428.5**	**$ 11,889**	**$ 1,623**	**$ 11**	**$ 928**	**$ 2,082**	**$ 1,923**	**$ 18,456**
Net earnings	**—**	**—**	**—**	**—**	**—**	**1,722**	**130**	**1,852**
Other comprehensive loss	**—**	**—**	**—**	**—**	**(592)**	**—**	**(75)**	**(667)**
Common shares issued	**34.8**	**1,756**	**—**	**(5)**	**—**	**—**	**—**	**1,751**
Subsidiary dividends paid to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(73)**	**(73)**
Dividends declared on common shares ($1.855 per share)	**—**	**—**	**—**	**—**	**—**	**(821)**	**—**	**(821)**
Dividends declared on preference shares	**—**	**—**	**—**	**—**	**—**	**(67)**	**—**	**(67)**
Disposition (Note 23)	**—**	**—**	**—**	**—**	**—**	**—**	**(318)**	**(318)**
Other	**—**	**—**	**—**	**5**	**—**	**—**	**(5)**	**—**
As at December 31, 2019	**463.3**	**$ 13,645**	**$ 1,623**	**$ 11**	**$ 336**	**$ 2,916**	**$ 1,582**	**$ 20,113**
As at December 31, 2017	421.1	$ 11,582	$ 1,623	$ 10	$ 61	$ 1,727	$ 1,746	$ 16,749
Net earnings	—	—	—	—	—	1,166	120	1,286
Other comprehensive income	—	—	—	—	867	—	124	991
Common shares issued	7.4	307	—	(1)	—	—	—	306
Subsidiary dividends paid to non-controlling interests	—	—	—	—	—	—	(85)	(85)
Dividends declared on common shares ($1.75 per share)	—	—	—	—	—	(745)	—	(745)
Dividends declared on preference shares	—	—	—	—	—	(66)	—	(66)
Other	—	—	—	2	—	—	18	20
As at December 31, 2018	428.5	$ 11,889	$ 1,623	$ 11	$ 928	$ 2,082	$ 1,923	$ 18,456

See accompanying Notes to Consolidated Financial Statements

1. DESCRIPTION OF BUSINESS

Fortis Inc. ("Fortis" or the "Corporation") is principally a North American regulated electric and gas utility holding company. Entities within the reporting segments that follow operate with substantial autonomy.

Regulated Utilities

ITC: Comprised of ITC Investment Holdings Inc., ITC Holdings Corp. and the electric transmission operations of its regulated operating subsidiaries, which include International Transmission Company ("ITCTransmission"), Michigan Electric Transmission Company, LLC ("METC"), ITC Midwest LLC ("ITC Midwest"), and ITC Great Plains, LLC. Fortis owns 80.1% of ITC and an affiliate of GIC Private Limited owns a 19.9% minority interest.

ITC owns and operates high-voltage transmission lines in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma.

UNS Energy: Comprised of UNS Energy Corporation, which primarily includes Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas").

UNS Energy's largest operating subsidiary, TEP, and UNS Electric are vertically integrated regulated electric utilities. They generate, transmit and distribute electricity to retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County and parts of Cochise County, as well as in Santa Cruz and Mohave counties. TEP also sells wholesale electricity to other entities in the western United States. Together they own generating capacity of 3,143 megawatts ("MW"), including 59 MW of solar capacity. Several generating assets in which they have an interest are jointly owned.

UNS Gas is a regulated gas distribution utility serving retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

Central Hudson: CH Energy Group, Inc., which includes primarily Central Hudson Gas & Electric Corporation. Central Hudson is a regulated electric and gas transmission and distribution utility that serves portions of New York State's Mid-Hudson River Valley and owns gas-fired and hydroelectric generating capacity totalling 65 MW.

FortisBC Energy: Comprised of FortisBC Energy Inc., which is the largest regulated distributor of natural gas in British Columbia, providing transmission and distribution services in over 135 communities. FortisBC Energy obtains natural gas supplies primarily from northeastern British Columbia and Alberta on behalf of most customers.

FortisAlberta: FortisAlberta Inc. is a regulated electricity distribution utility operating in a substantial portion of southern and central Alberta. It is not involved in the direct sale of electricity.

FortisBC Electric: Comprised of FortisBC Inc., an integrated regulated electric utility operating in the southern interior of British Columbia. It owns four hydroelectric generating facilities with a combined capacity of 225 MW. It also provides operating, maintenance and management services relating to five hydroelectric generating facilities in British Columbia that are owned by third parties.

Other Electric: Comprised of utilities in eastern Canada and the Caribbean, as follows: Newfoundland Power Inc. ("Newfoundland Power"); Maritime Electric Company, Limited ("Maritime Electric"); FortisOntario Inc. ("FortisOntario"); a 39% equity investment in Wataynikaneyap Power Limited Partnership ("Wataynikaneyap Partnership") (Note 10); an approximate 60% controlling interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities"); FortisTCI Limited and Turks and Caicos Utilities Limited (collectively, "FortisTCI"); and a 33% equity investment in Belize Electricity Limited ("Belize Electricity") (Note 10).

Newfoundland Power is an integrated regulated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador with a generating capacity of 143 MW, of which 97 MW is hydroelectric. Maritime Electric is an integrated regulated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI") with on-Island generating capacity of 140 MW. FortisOntario is comprised of three regulated electric utilities that provide service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario with a generating capacity of 5 MW. Wataynikaneyap Partnership is a partnership between 24 First Nations communities, Fortis and Algonquin Power & Utilities Corp. with a mandate of connecting remote First Nations communities to the electricity grid in Ontario through the development of new transmission lines.

In January 2019 Fortis reduced its equity investment in Wataynikaneyap Partnership from 49% to 39% to facilitate the inclusion of two additional First Nations communities into the partnership.

Caribbean Utilities is an integrated regulated electric utility and the sole electricity provider on Grand Cayman with a diesel-powered generating capacity of 161 MW. FortisTCI is comprised of two integrated regulated electric utilities that provide electricity to certain Turks and Caicos Islands and has a diesel-powered generating capacity of 91 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated

Energy Infrastructure: Comprised of long-term contracted generation assets in Belize and the Aitken Creek natural gas storage facility ("Aitken Creek") in British Columbia. Generation assets in Belize consist of three hydroelectric generating facilities with a combined capacity of 51 MW, held through the Corporation's indirectly wholly-owned subsidiary Belize Electric Company Limited ("BECOL"). The output is sold to Belize Electricity under 50-year power purchase agreements ("PPAs"). Fortis indirectly owns 93.8% of Aitken Creek, with the remainder owned by BP Canada Energy Company. Aitken Creek is the only underground natural gas storage facility in British Columbia and has a working gas capacity of 77 billion cubic feet. The long-term contracted generation assets in British Columbia, the Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), were sold on April 16, 2019 (Note 23).

Corporate and Other: Captures expenses and revenues not specifically related to any reportable segment and those business operations that are below the required threshold for segmented reporting, including net corporate expenses of Fortis.

2. REGULATION

General

The earnings of the Corporation's regulated utilities are determined under cost of service ("COS") regulation, with some using performance-based rate setting ("PBR") mechanisms.

Under COS regulation, the regulator sets customer rates to permit a reasonable opportunity for the timely recovery of the estimated costs of providing service, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). Under PBR mechanisms, formulae are generally applied that incorporate inflation and assumed productivity improvements for a set term.

The ability to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") may depend on achieving the forecasts established in the rate-setting process. There can be varying degrees of regulatory lag between when costs are incurred and when they are reflected in customer rates.

The Corporation's regulated utilities, where applicable, are permitted by their respective regulators to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms (Note 9).

ITC

ITC is regulated by the Federal Energy Regulatory Commission ("FERC") under the *Federal Power Act* (United States). Rates are set annually, using FERC-approved cost-based formula rate templates, and remain in effect for one year, which provides timely cost recovery. An annual true-up mechanism compares actual revenue requirements to billed revenues, and any variances are accrued and reflected in future rates within a two-year period. The formula rates do not require annual FERC approvals, although inputs remain subject to legal challenge by customers with FERC. ITC's allowed ROE ranged from 9.88% up to a maximum of 12.24% with incentive adders on a capital structure of 60% common equity for 2019 and 2018, reflecting the impact of a November 2019 order discussed below under "ROE Complaints".

Incentive Adder Complaint
In April 2018 a third-party complaint was filed with FERC challenging the independence incentive adders that are included in transmission rates charged by ITCTransmission, METC and ITC Midwest (collectively, "ITC's MISO Subsidiaries"), which operate in the Midcontinent Independent System Operator ("MISO") region. The adder allowed up to 0.50% or 1.00% to be added to the authorized ROE, subject to any ROE cap established by FERC. In October 2018 FERC issued an order reducing the adders to 0.25%, effective April 20, 2018. This equated to a 0.25% decrease in ROE, down from the approximate 0.50% that ITC was earning in rates previously approved by FERC. ITC began reflecting the 0.25% adder in transmission rates in November 2018. ITC's MISO Subsidiaries sought rehearing of this order in 2018, which was denied by FERC. In September 2019 ITC's MISO Subsidiaries filed an appeal in the U.S. Court of Appeal. The final resolution of this matter is not expected to have a material impact on the Corporation's earnings or cash flows.

ROE Complaints
Two third-party complaints requested that the base ROE for MISO transmission owners, including ITC's MISO Subsidiaries, be found to no longer be just or reasonable. The complaints cover two consecutive 15-month periods from November 2013 through February 2015 (the "Initial Refund Period" or "Initial Complaint") and February 2015 through May 2016 (the "Second Refund Period" or "Second Complaint").

In June 2016 the presiding Administrative Law Judge ("ALJ") issued an initial decision on the Second Complaint, recommending a base ROE of 9.70%, up to a maximum of 10.68% with incentive adders. Pending an order from FERC, an estimated regulatory liability of $206 million (US$151 million) had been recognized as at December 31, 2018 based on the ALJ's initial decision (Note 9).

In September 2016 FERC ordered that the base ROE for the Initial Refund Period be set at 10.32%, down from 12.38%, up to a maximum of 11.35% with incentive adders. The resultant rates applied prospectively from September 2016 until an approved ROE was established for the Second Refund Period. The total refund for the Initial Complaint as a result of the September 2016 FERC order was $158 million (US$118 million), including interest, and was paid in 2017.

In November 2019 FERC issued a decision on ITC's ROE Complaints ("November 2019 FERC Order"), which determined that the base ROE for the Initial Complaint and from September 2016 onward be 9.88%, up to a maximum of 12.24% with incentive adders. FERC also dismissed the Second Complaint, resulting in a ROE for that period of 12.38% plus incentive adders with no refund required. In addition, as an ROE complaint had not been filed for the period of May 2016 to September 2016, the ROE for that period continued to be 12.38% plus incentive adders with no refund required. The regulated utilities in the MISO region, including ITC, sought rehearing of this order on the basis that it will not allow utilities to earn a reasonable rate of return on investment. In January 2020 FERC issued an order granting the rehearing for further consideration, effectively extending FERC's review.

As at December 31, 2019, a regulatory liability of $91 million (US$70 million) was recognized related to the impact of the November 2019 FERC Order on the Initial Refund Period and for the period from September 2016 to December 2019 (Note 9). Additionally, the regulatory liability of $206 million (US$151 million) as at December 31, 2018 (Note 9), related to the Second Complaint, was reversed in 2019. The net impact of the November 2019 FERC Order was an increase in revenue and a decrease in interest expense resulting in an increase in net earnings of $79 million of which Fortis' share was $63 million. The favourable impact was comprised of: (i) $83 million related to the net reversal of liabilities established in prior periods; partially offset by (ii) $20 million related to the 2019 impact of a reduced ROE.

Based on the outcome of the request for rehearing, it is possible the ROE and refunds could materially change from those recognized in 2019.

Notices of Inquiry
In March 2019 FERC issued a notice of inquiry ("NOI") seeking comments on whether and how to improve its electric transmission incentives policy. The outcome may impact the existing incentive adders that are included in transmission rates charged by transmission owners, including ITC. Also in March 2019, FERC issued a second NOI seeking comments on whether and how recent policies concerning the determination of the base ROE for electric utilities should be modified. The comment period for both NOI proceedings has ended. The outcome may impact ITC's future ROE and incentive adders.

UNS Energy

UNS Energy is regulated by the Arizona Corporation Commission ("ACC") and certain activities are subject to regulation by FERC under the *Federal Power Act* (United States). UNS Energy uses a historical test year to establish retail electricity and gas rates.

TEP's rates reflect an allowed ROE of 9.75% on a capital structure of approximately 50% common equity. Effective August 1, 2016, UNS Electric's rates reflect an allowed ROE of 9.5% on a capital structure of 52.8% common equity. Effective May 1, 2012, UNS Gas' rates reflect an allowed ROE of 9.75% on a capital structure of 50.8% common equity.

General Rate Application
In April 2019 TEP filed a general rate application with the ACC requesting an increase in non-fuel revenue of US$99 million, effective May 1, 2020, with electricity rates based on a 2018 historical test year. Intervenor testimony in relation to TEP's revenue requirement and rate design was filed in October 2019. The application, adjusted for rebuttal testimony filed by TEP in November 2019, includes a request to increase TEP's allowed ROE to 10.00% from 9.75% and the equity component of its capital structure to 53% from 50% on a rate base of US$2.7 billion. Hearings before the ALJ commenced in January and a decision is expected by mid-2020.

Central Hudson

Central Hudson is regulated by the New York State Public Service Commission ("PSC") and certain activities are subject to regulation by FERC under the *Federal Power Act* (United States). Central Hudson uses a future test year to establish rates.

Pursuant to a three-year settlement agreement arising from a 2017 general rate application, Central Hudson's rates reflect an allowed ROE of 8.8% on a capital structure of 48%, 49% and 50% common equity as of July 1, 2018, 2019 and 2020, respectively. Prior thereto, effective July 1, 2015, Central Hudson's allowed ROE was 9.0% on a capital structure of 48% common equity.

Central Hudson is also subject to an earnings sharing mechanism whereby the Company and its customers share equally earnings between 50 and 100 basis points above the allowed ROE. Earnings beyond that are primarily returned to customers.

FortisBC Energy and FortisBC Electric

FortisBC Energy and FortisBC Electric are regulated by the British Columbia Utilities Commission ("BCUC") pursuant to the *Utilities Commission Act* (British Columbia), and are subject to multi-year PBR plans whereby a going-in revenue requirement is first established and used to set initial rates and thereafter a prescribed formula is applied annually to the previous year's rates to establish new rates for the remainder of the multi-year period.

The PBR plans for the most recent term of 2014 through 2019 incorporate incentive mechanisms for improving operating and capital expenditure efficiencies. Operation and maintenance expenses and base capital expenditures during the PBR period are subject to an incentive formula reflecting incremental costs for inflation and half of customer growth, less a fixed productivity adjustment factor of 1.1% for FortisBC Energy and 1.03% for FortisBC Electric each year. The approved PBR plans also include a 50/50 sharing of variances from the formula-driven operation and maintenance expenses and capital expenditures over the PBR period, and a number of service quality measures designed to ensure FortisBC Energy and FortisBC Electric maintain specified service levels.

FortisBC Energy is the benchmark utility in British Columbia, as designated by the BCUC, and effective January 1, 2016, its rates reflected an allowed ROE of 8.75% on a capital structure of 38.5% common equity. Effective January 1, 2016, FortisBC Electric's rates reflected an allowed ROE of 9.15% on a capital structure of 40% common equity.

In March 2019 FortisBC Energy and FortisBC Electric filed applications with the BCUC requesting approval of a multi-year rate plan and PBR methodology for 2020-2024. A decision is expected in mid-2020.

FortisAlberta

FortisAlberta is regulated by the Alberta Utilities Commission ("AUC") pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Act* (Alberta), the *Hydro and Electric Energy Act* (Alberta) and the *Alberta Utilities Commission Act* (Alberta). FortisAlberta is subject to multi-year PBR plans for 2018-2022 whereby a going-in revenue requirement is first established and used to set initial rates and thereafter a prescribed formula is applied annually to the previous year's rates to establish new rates for the remainder of the multi-year period.

The PBR plans include mechanisms for the recovery or settlement of items determined to flow through directly to customers ("Y factor") and the recovery of costs related to capital expenditures that are not being recovered through the formula ("capital tracker" or "K-bar"). It also includes a Z factor, a PBR re-opener, and an efficiency carry-over mechanism. The Z factor permits an application for recovery of costs, subject to certain thresholds, related to significant unforeseen events. The PBR re-opener permits, subject to certain thresholds, an application to re-open and review the PBR plan to address specific problems with its design or operation. The efficiency carry-over mechanism provides an efficiency incentive by permitting the Company to continue to benefit from any efficiency gains achieved during the PBR term for two years following the end of that term.

Pursuant to generic cost of capital proceedings completed in 2018, FortisAlberta's rates reflect an allowed ROE of 8.5% on a capital structure of 37% common equity for 2018-2020, unchanged from 2017.

Second-Term Performance-Based Rate-Setting Proceeding
The AUC has ongoing proceedings to review regulatory applications for rebasing inputs included in PBR rates for 2018-2022, including anomaly-related adjustments and approved changes to depreciation parameters.

In January 2020 the AUC issued two decisions: (i) confirming that changes to depreciation parameters will be incorporated into incremental funding mechanisms; and (ii) establishing new criteria for anomaly-related adjustments. PBR utilities in Alberta are permitted to file depreciation studies by July 2020 and were required to submit their intent to file an anomaly-related adjustment application by February 7, 2020. FortisAlberta does not anticipate filing a depreciation study in 2020 and did notify the AUC of its intent to file an anomaly-related adjustment application.

Generic Cost of Capital Proceeding
In December 2018 the AUC initiated a generic cost of capital proceeding to consider a formula-based approach to setting the allowed ROE beginning in 2021 and whether any process changes are necessary for determining capital structure in years in which a ROE formula is in place. In April 2019 the AUC determined that a traditional non-formulaic approach for assessing ROE and deemed capital structure would be used in 2021, with consideration of a formula-based approach for determining the allowed ROE for 2022 and subsequent years. Expert evidence was filed in January 2020 with an oral hearing scheduled for April 2020. An AUC decision is expected later in 2020.

2018 Alberta Independent System Operator Tariff Application
In September 2019 the AUC issued a decision that addressed, among other things, a proposal to change how the Alberta Electric System Operator's customer contribution policy is accounted for between distribution facility owners, such as FortisAlberta, and transmission facility owners ("TFO"). The decision prevents any future investment by FortisAlberta under the policy and directs that the unamortized customer contributions of approximately $400 million as at December 31, 2017, which form part of FortisAlberta's rate base, be transferred to the incumbent TFO in FortisAlberta's service area.

In October 2019 FortisAlberta filed evidence to oppose the decision. Implementation of the order has been suspended and the decision remains under review by the AUC. It is expected that the decision will remain under review through the first quarter of 2020. The likely outcome of this process and potential impacts, if any, cannot be determined at this time.

Other Electric

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities under the *Public Utilities Act* (Newfoundland and Labrador) and uses a future test year to establish rates. Effective 2019 to 2020, and consistent with 2018, Newfoundland Power's rates reflect an allowed ROE of 8.5% on a capital structure of 45% common equity.

Maritime Electric is regulated by the Island Regulatory and Appeals Commission under the provisions of the *Electric Power Act* (PEI), the *Renewable Energy Act* (PEI) and the *Electric Power (Electricity Rate-Reduction) Amendment Act* (PEI), and uses a future test year to establish rates. Effective March 1, 2019 for a three-year period, and consistent with 2018, Maritime Electric's rates reflect an allowed ROE of 9.35% on a capital structure of 40% common equity.

FortisOntario's three electric utilities are regulated by the Ontario Energy Board under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario). Two of FortisOntario's utilities use a future test year to establish rates under five-year PBR plans whereby a going-in revenue requirement is first established and used to set initial rates and thereafter a prescribed formula using inflationary factors less an efficiency target is applied annually to the previous year's rates to establish new rates for the remainder of the five-year period. The allowed ROEs ranged from 8.78% to 9.30% for both 2019 and 2018, on a capital structure of 40% common equity. FortisOntario's remaining utility is subject to a 35-year franchise agreement, expiring in 2033, whereby rates are based on a price cap with commodity cost flow through and with the base revenue requirement adjusted annually for inflation, load growth and customer growth.

Caribbean Utilities operates under licences from the Government of the Cayman Islands. Its exclusive transmission and distribution licence is for an initial 20-year period, expiring in April 2028, with a provision for automatic renewal. Its non-exclusive generation licence is for a 25-year term, expiring in November 2039. It is regulated under a rate-cap adjustment mechanism based on published consumer price indices. The licences detail the role of the Cayman Islands Utility Regulation and Competition Office, which oversees all licences, establishes and enforces licence standards, reviews the rate-cap adjustment mechanism, and annually approves capital expenditures. Its allowed ROA for 2019 was in the range of 7.50% to 9.50% (7.00% to 9.00% for 2018).

FortisTCI operates under 50-year licences from the Government of the Turks and Caicos Islands, which expire in 2036 and 2037. Rates reflect a historical test year and a targeted allowed ROA of between 15.0% and 17.5% (the "Allowable Operating Profit"). The Allowable Operating Profit is based on a calculated rate base, including interest on the cumulative amount by which actual operating profits fall short of the Allowable Operating Profit (the "Cumulative Shortfall"). The calculated Allowable Operating Profit and Cumulative Shortfall are submitted to the Government annually. The recovery of the Cumulative Shortfall is dependent on future sales volumes and expenses. The achieved ROAs at the utilities have been significantly lower than those allowed as a result of the inability, due to economic and political factors, to increase rates to support significant capital investment in recent years.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These consolidated financial statements have been prepared and presented in accordance with accounting principles generally accepted in the United States of America ("US GAAP") for rate-regulated entities, and are in Canadian dollars unless otherwise indicated.

These consolidated financial statements include the accounts of the Corporation and its subsidiaries, and a controlled variable interest entity up to the date of its disposition on April 16, 2019 (Note 23). They reflect the equity method of accounting for entities in which Fortis has significant influence, but not control, and proportionate consolidation for assets that are jointly owned with non-affiliated entities. Intercompany transactions have been eliminated, except for transactions between non-regulated and regulated entities in accordance with US GAAP for rate-regulated entities.

Cash and Cash Equivalents

Cash and cash equivalents include cash, cash held in margin accounts, and short-term deposits with initial maturities of three months or less from the date of deposit.

Allowance for Doubtful Accounts

Fortis and each subsidiary, other than ITC, maintain an allowance for doubtful accounts that is estimated based on a variety of factors, including receivables aging, historical experience, specific events such as customer bankruptcy and economic conditions. ITC recognizes losses for uncollectible accounts based upon their specific identification. Accounts receivable are written off in the period in which they are deemed uncollectible.

Inventories

Inventories, consisting of materials and supplies, gas, fuel and coal in storage, are measured at the lower of weighted average cost and net realizable value.

Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the utility rate-setting process and are subject to regulatory approval. Regulatory assets represent future revenues and/or receivables associated with certain costs incurred that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent: (i) future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process; or (ii) an obligation to provide future service that customers have paid for in advance.

Certain remaining recovery and settlement periods are those expected by management and the actual periods could differ based on regulatory approval.

Investments

Investments accounted for using the equity method are reviewed annually for potential impairment in value. Impairments are recognized when identified.

Property, Plant and Equipment

Property, plant and equipment ("PPE") are recognized at cost less accumulated depreciation. Contributions in aid of construction by customers and governments are recognized as a reduction in the cost of, and are amortized in a manner consistent with, the related PPE.

Depreciation rates of the Corporation's regulated utilities include a provision for estimated future asset removal costs not identified as a legal obligation. The provision is recognized as a long-term regulatory liability (Note 9) against which actual asset removal costs are netted when incurred.

Most of the Corporation's regulated utilities derecognize PPE on disposal or when no future economic benefits are expected from their use. Upon derecognition, any difference between cost and accumulated depreciation, net of salvage proceeds, is charged to accumulated depreciation. No gain or loss is recognized.

Through methodologies established by their respective regulators, the Corporation's regulated utilities capitalize: (i) overhead costs that are not directly attributable to specific PPE but relate to the overall capital expenditure plan; and (ii) an allowance for funds used during construction ("AFUDC"). The debt component of AFUDC totalling $40 million (2018 - $31 million) is reported as a reduction of finance charges and the equity component is reported as other income (Note 24). Both components are charged to earnings through depreciation expense over the estimated service lives of the applicable PPE.

At FortisAlberta the cost of PPE includes required contributions to the Alberta Electric System Operator ("AESO") toward funding the construction of transmission facilities (Note 2).

Excluding UNS Energy and Central Hudson, PPE includes inventory held for the development, construction and betterment of other assets. As required by its regulator, UNS Energy and Central Hudson recognize such items as inventory until used and reclassifies them to PPE once put into service.

Repairs and maintenance costs are charged to earnings in the period incurred. Replacements and betterments that extend the useful lives of PPE are capitalized.

PPE is depreciated using the straight-line method based on the estimated service lives of the assets. Depreciation rates for regulated PPE are approved by the respective regulators. Depreciation rates for 2019 ranged from 0.9% to 35.0% (2018 - 0.9% to 34.6%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, was 2.6% for 2019 (2018 – 2.5%).

The service life ranges and weighted average remaining service life of the Corporation's PPE as at December 31 were as follows.

	2019		2018	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	**5-80**	**32**	5-80	33
Gas	**15-95**	**36**	14-95	35
Transmission				
Electric	**20-90**	**43**	20-90	42
Gas	**5-85**	**32**	5-85	41
Generation	**1-85**	**25**	1-85	24
Other	**3-70**	**14**	3-70	15

Intangible Assets

Intangible assets are recorded at cost less accumulated amortization. Their useful lives are assessed to be either indefinite or finite.

Intangible assets with indefinite useful lives are not amortized and are tested for impairment annually, either individually or, where the particular entity also has goodwill, at the reporting unit level in conjunction with goodwill impairment testing. An annual review is completed to determine whether the indefinite life assessment continues to be supportable. If not, the resultant changes are made prospectively.

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets. Amortization rates for regulated intangible assets are approved by the respective regulators and ranged from 1.0% to 50.0% for 2019 (2018 – 1.0% to 50.0%).

The service life ranges and weighted average remaining service life of finite-life intangible assets as at December 31 were as follows.

	2019		2018	
(years)	Service Life Ranges	Weighted Average Remaining Service Life	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	3-10	4	3-10	4
Land, transmission and water rights	43-90	58	36-90	57
Other	10-100	12	10-100	13

Most of the Corporation's regulated utilities derecognize intangible assets on disposal or when no future economic benefits are expected from their use. Upon derecognition any difference between the cost and accumulated amortization of the asset, net of salvage proceeds, is charged to accumulated amortization. No gain or loss is recognized.

Impairment of Long-Lived Assets

The Corporation reviews the valuation of PPE, intangible assets with finite lives, and other long-term assets when events or changes in circumstances indicate that the carrying value may not exceed the total undiscounted cash flows expected to be generated by the asset. If that is determined to be the case, the asset is written down to estimated fair value and an impairment loss is recognized.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of the identifiable net assets related to business acquisitions.

Impairment testing is performed if an event or change in circumstances indicates that the fair value of a reporting unit may be below its carrying value. If so determined, goodwill is written down to estimated fair value and an impairment loss is recognized.

Otherwise, Fortis performs an annual assessment for each of the 11 reporting units having goodwill. The Corporation performs a qualitative assessment for certain reporting units and if it is determined that it is not likely that fair value is less than carrying value then a quantitative estimate of the fair value is not required. Otherwise, the primary method for estimating the fair value of the reporting units is the income approach, whereby net cash flow projections are discounted using an enterprise value method. Underlying estimates and assumptions, with varying degrees of uncertainty, include the amount and timing of expected future cash flows, growth rates, and discount rates.

A secondary valuation method, the market approach along with a reconciliation of the total estimated fair value of all reporting units to the Corporation's market capitalization, is also performed and evaluated.

Deferred Financing Costs

Issue costs, discounts and premiums are recognized against, and amortized over the life of, the related long-term debt.

Employee Future Benefits

Fortis and each subsidiary maintain one or a combination of defined benefit pension plans and defined contribution pension plans, as well as other post-employment benefit ("OPEB") plans, including certain health and dental coverage and life insurance benefits, for qualifying members. The costs of defined contribution pension plans are expensed as incurred.

For defined benefit pension and OPEB plans, the projected or accumulated benefit obligation and net benefit costs are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and, for OPEB plans, expected health care costs. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension or OPEB payments.

Defined benefit pension and OPEB plan assets are recognized at fair value. For the purpose of determining defined benefit pension cost, FortisBC Energy and Newfoundland Power use the market-related value whereby investment returns in excess of, or below, expected returns are recognized in the asset value over a period of three years.

The excess of any cumulative net actuarial gain or loss over 10% of the greater of: (i) the projected or accumulated benefit obligation; and (ii) the fair value or market-related value, as applicable, of plan assets at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

The net funded or unfunded status of defined benefit pension and OPEB plans, measured as the difference between the fair value of the plan assets and the projected or accumulated benefit obligation, is recognized on the Corporation's consolidated balance sheets.

For most of the Corporation's regulated utilities, any difference between defined benefit pension or OPEB plan costs ordinarily recognized under US GAAP and those recovered from customers in current rates is subject to deferral account treatment and is expected to be recovered from, or refunded to, customers in future rates (Note 9).

For most of the Corporation's regulated utilities, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension or OPEB plans, as applicable, which would otherwise be recognized in accumulated other comprehensive income, are subject to deferral account treatment (Note 9).

Revenue Recognition

Most revenue is derived from energy sales and the provision of transmission services to customers based on regulator-approved tariff rates. Most contracts have a single performance obligation, being the delivery of energy or the provision of transmission services. No component of the transaction price is allocated to unsatisfied performance obligations. Revenue is generally measured in kilowatt hours, gigajoules or transmission load delivered. The billing of energy sales is based on customer meter readings, which occur systematically throughout each month. The billing of transmission services at ITC is based on peak monthly load.

FortisAlberta is a distribution company and is required by its regulator to arrange and pay for transmission services with the AESO. This includes the collection of transmission revenue from its customers, which occurs through the transmission component of its regulator-approved rates. FortisAlberta reports transmission revenue and expenses on a net basis.

Electricity, gas and transmission service revenue includes an estimate for unbilled energy consumed or service provided since the last meter reading that has not been billed at the end of the reporting period. Sales estimates generally reflect an analysis of historical consumption in relation to key inputs, such as current energy prices, population growth, economic activity, weather conditions and system losses. Unbilled revenue accruals are adjusted in the periods actual consumption becomes known.

Generation revenue from non-regulated operations is recognized on delivery at contracted fixed or market rates.

Variable consideration is estimated at the most likely amount and reassessed at each reporting date until the amount is known. Variable consideration, including amounts subject to a future regulatory decision, is recognized as a refund liability until entitlement is certain.

Revenue excludes sales and municipal taxes collected from customers.

The Corporation has elected not to assess or account for any significant financing components associated with revenue billed in accordance with equal payment plans as the period between the transfer of energy to customers and the customers' payment is less than one year.

Revenue is disaggregated by geography, regulatory status, and substantially autonomous utility operations (Note 6). This represents the level of disaggregation used by the Corporation's President and Chief Executive Officer ("CEO") to allocate resources and evaluate performance.

Stock-Based Compensation

Compensation expense related to stock options is measured at the grant date using the Black-Scholes fair value option-pricing model and each grant is amortized to compensation expense as a single award evenly over the four-year vesting period, with the offsetting entry to additional paid-in capital.

Fortis satisfies stock option exercises by issuing common shares from treasury. Upon exercise, proceeds are credited to capital stock at the option prices and the fair value of the options, as previously recognized, is reclassified from additional paid-in capital to capital stock.

Fortis recognizes liabilities associated with its Directors' Deferred Share Unit ("DSU"), Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plans, all representing cash-settled awards, at fair value at each reporting date until settlement. The fair value of these liabilities is based on the five-day volume weighted average price ("VWAP") of the Corporation's common shares at the end of each reporting period. The VWAP as at December 31, 2019 was $53.97 (December 31, 2018 - $45.14). The fair value of the PSU liability is also based on the expected payout probability, based on historical performance in accordance with the defined metrics of each grant and management's best estimate.

Compensation expense is recognized on a straight-line basis over the vesting period, which for the PSU and RSU Plans is over the lesser of three years or the period to retirement eligibility and for the DSU Plan is at the time of grant. Forfeitures are accounted for as they occur.

Foreign Currency Translation

Assets and liabilities of the Corporation's foreign operations, all of which have a US dollar functional currency, are translated at the exchange rate in effect at the balance sheet date and the resultant unrealized translation gains and losses are recognized in accumulated other comprehensive income. The exchange rate as at December 31, 2019 was US$1.00=CAD$1.30 (December 31, 2018 – US$1.00=CAD$1.36).

Revenue and expenses of the Corporation's foreign operations are translated at the average exchange rate for the reporting period, which was US$1.00=CAD$1.33 for 2019 (2018 - US$1.00=CAD$1.30).

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate prevailing at the balance sheet date. Revenue and expenses denominated in foreign currencies are translated at the exchange rate prevailing at the transaction date. Translation gains and losses are recognized in earnings.

Translation gains and losses on foreign currency-denominated debt that is designated as an effective hedge of foreign net investments are recognized in other comprehensive income.

Derivatives and Hedging

Derivatives Not Designated as Hedges
Derivatives not designated as hedges are used by: (i) Fortis, to manage cash flow risk associated with forecast US dollar cash inflows and forecast future cash settlements of DSU, PSU and RSU obligations; (ii) UNS Energy, to meet forecast load and reserve requirements; and (iii) Aitken Creek, to manage commodity price risk, capture natural gas price spreads, and manage the financial risk of physical transactions. These derivatives are measured at fair value with changes thereto recognized in earnings.

Derivatives not designated as hedges are also used by UNS Energy, Central Hudson and FortisBC Energy to reduce energy price risk associated with purchased power and gas requirements. The settled amounts of these derivatives are generally included in regulated rates, as permitted by the respective regulators. These derivatives are measured at fair value with changes thereto recognized as regulatory assets or liabilities for recovery from, or refund to, customers in future rates (Note 9).

Derivatives that meet the normal purchase or normal sale scope exception are not measured at fair value and settled amounts are recognized in earnings as energy supply costs.

Derivatives Designated as Hedges
The Corporation, ITC and UNS Energy use cash flow hedges to manage interest rate risk. Unrealized gains and losses are initially recognized in accumulated other comprehensive income and reclassified to earnings when the underlying hedged transaction affects earnings. Any hedge ineffectiveness is immediately recognized in earnings.

The Corporation's earnings from, and net investments in, foreign subsidiaries and equity-accounted investments are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has hedged a portion of this exposure through US dollar-denominated debt at the corporate level. Exchange rate fluctuations associated with the translation of this debt and the foreign net investments are recognized in accumulated other comprehensive income.

Presentation of Derivatives
The fair values of derivatives are recognized as current or long-term assets and liabilities depending on the timing of settlements and resulting cash flows. Derivatives under master netting agreements and collateral positions are presented on a gross basis. Cash flows associated with the settlement of all derivatives are presented in operating activities in the consolidated statements of cash flows.

Income Taxes

The Corporation and its taxable subsidiaries follow the asset and liability method of accounting for income taxes. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

Deferred income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are "more likely than not" to be realized. They are measured using enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in earnings in the period when the change occurs. Valuation allowances are recognized when it is "more likely than not" that all, or a portion of, a deferred income tax asset will not be realized.

Customer rates at ITC, UNS Energy, Central Hudson and Maritime Electric reflect current and deferred income tax. Customer rates at FortisAlberta reflect current income tax. Customer rates at FortisBC Energy, FortisBC Electric, Newfoundland Power and FortisOntario reflect current income tax and, for certain regulatory balances, deferred income tax. Caribbean Utilities, FortisTCI and, for the 50-year term of its PPAs, BECOL are not subject to income tax.

Differences between the income tax expense or recovery recognized under US GAAP and that reflected in current customer rates, which is expected to be recovered from, or refunded to, customers in future rates, are recognized as regulatory assets or liabilities (Note 9).

At FortisAlberta the capital cost allowance pool for certain PPE for rate-setting purposes is different from that prescribed for Canadian tax filing purposes. In a future reporting period yet to be determined, the difference may result in reported income tax expense exceeding that reflected in customer rates.

Fortis does not recognize deferred income taxes on temporary differences related to investments in foreign subsidiaries where it intends to indefinitely reinvest earnings. The difference between the carrying values of these foreign investments and their tax bases, resulting from unrepatriated earnings and currency translation adjustments, is approximately $2.8 billion as at December 31, 2019 (December 31, 2018 - $2.3 billion). If such earnings are repatriated, the Corporation may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is impractical.

Tax benefits associated with actual or expected income tax positions are recognized when the "more likely than not" recognition threshold is met. The tax benefits are measured at the largest amount of benefit that is greater than 50% likely to be realized upon settlement.

Income tax interest and penalties are recognized as income tax expense when incurred.

Asset Retirement Obligations

The Corporation's subsidiaries have asset retirement obligations ("AROs") associated with certain generation, transmission, distribution and interconnection assets, including land and environmental remediation and/or asset removal. These assets and related licences, permits, right-of-ways and agreements are reasonably expected to effectively exist and operate in perpetuity due to their nature. Consequently, where the final date and cost of remediation and/or removal of the noted assets cannot be reasonably determined, AROs have not been recognized.

Otherwise, AROs are recognized at fair value in the period incurred as an increase in PPE and long-term other liabilities (Note 17) if a reasonable estimate of fair value can be determined. Fair value is estimated as the present value of expected future cash outlays, discounted at a credit-adjusted risk-free interest rate. The increase in the liability due to the passage of time is recognized through accretion and the capitalized cost is depreciated over the useful life of the asset. Accretion and depreciation expense are deferred as a regulatory asset or liability based on regulatory recovery of these costs. Actual settlement costs are recognized as a reduction in the accrued liability.

Contingencies

Fortis and its subsidiaries are subject to various legal proceedings and claims that arise in the normal course of business. Management makes judgments regarding the future outcome of contingent events and recognizes a loss based on its best estimate when it is determined that such loss, or range of loss, is probable and can be reasonably estimated. Legal fees are expensed as incurred. When a loss is recoverable in future rates, a regulatory asset is also recognized.

Management regularly reviews current information to determine whether recognized provisions should be adjusted and new provisions are required. However, estimating probable losses requires considerable judgment about potential actions by third parties and matters are often resolved over long periods of time. Actual outcomes may differ materially from the amounts recognized.

New Accounting Policies

Leases
Effective January 1, 2019, the Corporation adopted Accounting Standards Update ("ASU") No. 2016-02, *Leases*, that requires lessees to recognize a right-of-use asset and lease liability for all leases with a lease term greater than 12 months, along with additional disclosures (Note 16).

At lease inception, the right-of-use asset and liability are both measured at the present value of future lease payments, excluding variable payments that are based on usage or performance. Future lease payments include both lease components (e.g., rent, real estate taxes and insurance costs) and non-lease components (e.g., common area maintenance costs), which Fortis accounts for as a single lease component. The present value is calculated using the rate implicit in the lease or a lease-specific secured interest rate based on the remaining lease term. Renewal options are included in the lease term when it is reasonably certain that the option will be exercised.

Finance leases are depreciated over the lease term, except where: (i) ownership of the asset is transferred at the end of the lease term, in which case depreciation is over the estimated service life of the underlying asset; and (ii) the regulator has approved a different recovery methodology for rate-setting purposes, in which case the timing of the expense recognition will conform to the regulator's requirements.

Fortis applied the transition provisions of the new standard as of the adoption date and did not retrospectively adjust prior periods in accordance with the modified retrospective approach. Fortis elected a package of implementation options, referred to as practical expedients, that allowed it to not reassess: (i) whether existing contracts, including land easements, are or contain a lease; (ii) the classification of existing leases; or (iii) the initial direct costs for existing leases. Fortis also utilized the hindsight practical expedient to determine the lease term. Upon adoption, Fortis did not identify or record an adjustment to the opening balance of retained earnings, and there was no impact on net earnings or cash flows.

Hedging
Effective January 1, 2019, the Corporation adopted ASU No. 2017-12, *Targeted Improvements to Accounting for Hedging Activities,* which better aligns risk management activities and financial reporting for hedging relationships through changes to designation, measurement, presentation and disclosure guidance. Adoption did not have a material impact on the consolidated financial statements and related disclosures.

Fair Value Measurement Disclosures
Effective January 1, 2019, the Corporation adopted ASU No. 2018-13, *Changes to the Disclosure Requirements for Fair Value Measurement*, which improves the effectiveness of financial statement note disclosures by clarifying what is required and important to users of the financial statements. The adoption of this ASU removed the following disclosures for all periods presented: (i) the amount of, and reasons for, transfers between level 1 and level 2 of the fair value hierarchy; (ii) the policy for the timing of transfers between levels; and (iii) the valuation processes for level 3 fair value measurements.

Pensions and Other Post-Retirement Plan Disclosures
Effective December 31, 2019, the Corporation early adopted, on a retrospective basis, ASU No. 2018-14, *Changes to the Disclosure Requirements for Defined Benefit Plans*, which modifies the disclosure requirements for employers with defined pension or other post-retirement plans and clarifies disclosure requirements. In particular, it removed the following disclosures: (i) the amounts in accumulated other comprehensive income expected to be recognized as components of net period benefit costs over the next fiscal period; and (ii) the effects of a one-percentage-point change on the assumed health care costs and the change in rates on service cost, interest cost and the benefit obligation for post-retirement health care benefits (Note 26).

Use of Accounting Estimates

The preparation of these consolidated financial statements in accordance with US GAAP requires management to make estimates and judgments, including those arising from matters dependent upon the finalization of regulatory proceedings, that affect the reported amounts of assets, liabilities, revenues, expenses, gains and losses. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time they are made, with any adjustments being recognized in the period they become known. Actual results may differ significantly from these estimates.

4. FUTURE ACCOUNTING PRONOUNCEMENTS

Income Taxes

ASU No. 2019-12, *Simplifying the Accounting for Income Taxes*, issued in December 2019, is effective for Fortis January 1, 2021, with early adoption permitted. Principally, it improves consistent application of, and clarifies, existing income tax guidance. Fortis is assessing the impact that adoption will have on its consolidated financial statements.

5. SEGMENTED INFORMATION

General

Fortis segments its business based on regulatory status, service territory, and the information used by its President and CEO in deciding how to allocate resources. Segment performance is evaluated primarily on net earnings attributable to common equity shareholders.

Related-party and inter-company transactions

Related-party transactions are in the normal course of operations and are measured at the amount of consideration agreed to by the related parties. There were no material related-party transactions in 2019 or 2018.

Inter-company balances, transactions and profit are eliminated on consolidation, except for certain inter-company transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities, which are summarized below.

(in millions)	**2019**	2018
Sale of capacity from Waneta Expansion to FortisBC Electric [(1)]	**$ 17**	$ 47
Lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy	**23**	25

[(1)] *Reflects amounts to the April 16, 2019 disposition of the Waneta Expansion (Note 23)*

As at December 31, 2019, accounts receivable included approximately $8 million due from Belize Electricity (December 31, 2018 - $16 million).

The Corporation periodically provides short-term financing to subsidiaries to support capital expenditures, acquisitions and seasonal working capital requirements. As at December 31, 2019, there were inter-segment loans outstanding of $279 million (December 31, 2018 - $nil), payable on demand with a weighted average interest rate of 2.48%. Total interest charged in 2019 was $2 million.

Year Ended December 31, 2019 *(in millions)*	REGULATED								NON-REGULATED			
	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Sub total**	**Energy Infra-structure**	**Corporate and Other**	**Inter-segment eliminations**	**Total**
Revenue	$ 1,761	$ 2,212	$ 917	$ 1,331	$ 598	$ 418	$ 1,467	**$ 8,704**	**$ 82**	**$ —**	**$ (3)**	**$ 8,783**
Energy supply costs	—	814	254	438	—	121	890	**2,517**	**3**	**—**	**—**	**2,520**
Operating expenses	489	650	451	333	145	107	188	**2,363**	**36**	**56**	**(3)**	**2,452**
Depreciation and amortization	270	297	79	235	214	62	171	**1,328**	**20**	**2**	**—**	**1,350**
Gain on disposition	—	—	—	—	—	—	—	**—**	**—**	**577**	**—**	**577**
Operating income	1,002	451	133	325	239	128	218	**2,496**	**23**	**519**	**—**	**3,038**
Other income, net	37	28	17	16	2	4	2	**106**	**2**	**30**	**—**	**138**
Finance charges	290	130	46	136	104	72	77	**855**	**—**	**180**	**—**	**1,035**
Income tax expense	174	57	19	39	6	6	20	**321**	**(1)**	**(31)**	**—**	**289**
Net earnings	575	292	85	166	131	54	123	**1,426**	**26**	**400**	**—**	**1,852**
Non-controlling interests	104	—	—	1	—	—	17	**122**	**8**	**—**	**—**	**130**
Preference share dividends	—	—	—	—	—	—	—	**—**	**—**	**67**	**—**	**67**
Net earnings attributable to common equity shareholders	$ 471	$ 292	$ 85	$ 165	$ 131	$ 54	$ 106	**$ 1,304**	**$ 18**	**$ 333**	**$ —**	**$ 1,655**
Goodwill	$ 7,970	$ 1,794	$ 586	$ 913	$ 228	$ 235	$ 251	**$ 11,977**	**$ 27**	**$ —**	**$ —**	**$ 12,004**
Total assets	19,799	10,205	3,726	7,305	4,831	2,328	4,185	**52,379**	**711**	**641**	**(327)**	**53,404**
Capital expenditures	1,148	915	317	463	423	106	295	**3,667**	**28**	**25**	**—**	**3,720**

Year Ended December 31, 2018 *(in millions)*												
Revenue	$ 1,504	$ 2,202	$ 924	$ 1,187	$ 579	$ 408	$ 1,412	$ 8,216	$ 184	$ —	$ (10)	$ 8,390
Energy supply costs	—	868	315	322	—	135	853	2,493	2	—	—	2,495
Operating expenses	448	609	410	308	167	105	182	2,229	40	28	(10)	2,287
Depreciation and amortization	234	272	71	219	192	61	160	1,209	32	2	—	1,243
Operating income	822	453	128	338	220	107	217	2,285	110	(30)	—	2,365
Other income, net	40	10	7	7	1	3	1	69	1	(10)	—	60
Finance charges	285	104	41	134	100	40	76	780	6	188	—	974
Income tax expense	139	66	20	55	1	14	22	317	6	(158)	—	165
Net earnings	438	293	74	156	120	56	120	1,257	99	(70)	—	1,286
Non-controlling interests	77	—	—	1	—	—	15	93	27	—	—	120
Preference share dividends	—	—	—	—	—	—	—	—	—	66	—	66
Net earnings attributable to common equity shareholders	$ 361	$ 293	$ 74	$ 155	$ 120	$ 56	$ 105	$ 1,164	$ 72	$ (136)	$ —	$ 1,100
Goodwill	$ 8,369	$ 1,884	$ 615	$ 913	$ 227	$ 235	$ 260	$ 12,503	$ 27	$ —	$ —	$ 12,530
Total assets	19,798	10,182	3,670	6,815	4,691	2,244	4,119	51,519	1,478	127	(73)	53,051
Capital expenditures	998	599	245	486	433	106	300	3,167	44	7	—	3,218

6. REVENUE

(in millions)		**2019**		2018
Electric and gas revenue				
United States				
ITC	**$**	**1,697**	$	1,539
UNS Energy		**1,966**		1,993
Central Hudson		**894**		963
Canada				
FortisBC Energy		**1,289**		1,136
FortisAlberta		**576**		554
FortisBC Electric		**362**		354
Newfoundland Power		**671**		651
Maritime Electric		**209**		200
FortisOntario		**206**		197
Caribbean				
Caribbean Utilities		**270**		253
FortisTCI		**85**		78
Total electric and gas revenue		**8,225**		7,918
Other services revenue [(1)]		**374**		408
Revenue from contracts with customers		**8,599**		8,326
Alternative revenue [(2)]		**116**		16
Other revenue		**68**		48
Total revenue	**$**	**8,783**	$	8,390

(1) *Includes $273 million and $234 million from regulated operations for 2019 and 2018, respectively*
(2) *Includes a $91 million adjustment associated with the November 2019 FERC Order (Notes 2 and 9)*

Revenue from Contracts with Customers
Electric and gas revenue includes revenue from the sale and/or delivery of electricity and gas, transmission revenue, and wholesale electric revenue, all based on regulator-approved tariff rates.

Other services revenue includes: (i) management fee revenue at UNS Energy for the operation of Springerville Units 3 and 4; (ii) revenue from storage optimization activities at Aitken Creek; (iii) the sale of energy from non-regulated generation operations, including the Waneta Expansion up to its disposition on April 16, 2019 (Note 23); and (iv) revenue from other services that reflect the ordinary business activities of Fortis' utilities.

Alternative Revenue
Alternative revenue programs allow utilities to adjust future rates in response to past activities or completed events if certain criteria are met. Alternative revenue is recognized on an accrual basis with a corresponding regulatory asset or liability until the revenue is settled. Upon settlement, revenue is not recognized as revenue from contracts with customers but rather as settlement of the regulatory asset or liability. The Corporation's significant alternative revenue programs are summarized as follows.

ITC's formula rates include an annual true-up mechanism that compares actual revenue requirements to billed revenue, and any under- or over-collections are accrued as a regulatory asset or liability and reflected in future rates within a two-year period (Note 9). The formula rates do not require annual regulatory approvals, although inputs remain subject to legal challenge.

UNS Energy's lost fixed-cost recovery mechanism ("LFCR") surcharge recovers lost fixed costs, as measured by a reduction in non-fuel revenue, associated with energy efficiency savings and distributed generation. To recover the LFCR regulatory asset, UNS Energy is required to file an annual LFCR adjustment request with the ACC for the LFCR revenue recognized in the prior year. The recovery is subject to a year-over-year cap of 2% of total retail revenue. UNS Energy's demand side management surcharge, which is approved by the ACC annually, compensates for the costs to design and implement cost-effective energy efficiency and demand response programs until such costs, along with a performance incentive, are reflected in non-fuel base rates.

At FortisBC Energy and FortisBC Electric, the earnings sharing mechanism allows for a 50/50 sharing of variances from operating and maintenance expenses and capital expenditures approved as part of the annual revenue requirement. This mechanism was in place until the expiry of the current PBR plan in 2019. Additionally, variances in the forecast versus actual customer-use rates are captured throughout the year in a revenue stabilization adjustment mechanism and a flow-through deferral account, both of which are either refunded to, or recovered from, customers in rates within two years.

Other Revenue
Other revenue primarily includes gains or losses on energy contract derivatives and lease revenue.

7. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

(in millions)	**2019**	2018
Trade accounts receivable	**$ 504**	$ 538
Unbilled accounts receivable	**601**	575
Allowance for doubtful accounts	**(35)**	(33)
Total accounts receivable	**1,070**	1,080
Income tax receivable	**35**	91
Other [1]	**192**	186
	$ 1,297	$ 1,357

[1] *Consists mainly of customer billings for non-core services, gas mitigation costs and collateral deposits for gas purchases at FortisBC Energy, and the fair value of derivative instruments (Note 28)*

8. INVENTORIES

(in millions)	**2019**	2018
Materials and supplies	**$ 294**	$ 280
Gas and fuel in storage	**69**	87
Coal inventory	**31**	31
	$ 394	$ 398

9. REGULATORY ASSETS AND LIABILITIES

(in millions)		2019		2018
Regulatory assets				
Deferred income taxes (Notes 3 and 25)	**$**	**1,556**	$	1,532
Employee future benefits (Notes 3 and 26)		**530**		485
Deferred energy management costs *(i)*		**279**		230
Rate stabilization and related accounts *(ii)*		**208**		90
Derivatives (Notes 3 and 28)		**119**		57
Deferred lease costs *(iii)*		**116**		110
Generation early retirement costs *(iv)*		**88**		98
Manufactured gas plant site remediation deferral (Note 17)		**81**		73
Other regulatory assets *(v)*		**406**		400
Total regulatory assets		**3,383**		3,075
Less: Current portion		**(425)**		(324)
Long-term regulatory assets	**$**	**2,958**	$	2,751
Regulatory liabilities				
Deferred income taxes (Notes 3 and 25)	**$**	**1,440**	$	1,574
Asset removal cost provision (Note 3)		**1,187**		1,169
Rate stabilization and related accounts *(ii)*		**166**		220
Energy efficiency liability *(vi)*		**101**		106
Renewable energy surcharge *(vii)*		**94**		85
ROE complaints liability (Note 2)		**91**		206
Electric and gas moderator account *(viii)*		**45**		60
Employee future benefits (Notes 3 and 26)		**45**		37
Other regulatory liabilities *(v)*		**189**		169
Total regulatory liabilities		**3,358**		3,626
Less: Current portion		**(572)**		(656)
Long-term regulatory liabilities	**$**	**2,786**	$	2,970

(i) *Deferred Energy Management Costs*
Certain regulated subsidiaries provide energy management services to facilitate customer energy efficiency programs where the related expenditures have been deferred as a regulatory asset and are being amortized, and recovered from customers through rates, on a straight-line basis over periods ranging from 1 to 10 years.

(ii) *Rate Stabilization and Related Accounts*
Rate stabilization accounts mitigate the earnings volatility otherwise caused by variability in the cost of fuel, purchased power and natural gas above or below a forecast or predetermined level, and by weather-driven volume variability. At certain utilities, revenue decoupling mechanisms minimize the earnings impact resulting from reduced energy consumption as energy efficiency programs are implemented. Resultant deferrals are recovered from, or refunded to, customers in future rates as approved by the respective regulators.

Related accounts include the annual true-up mechanism at ITC (Note 6).

(iii) *Deferred Lease Costs*
Deferred lease costs at FortisBC Electric primarily relate to the Brilliant Power Purchase Agreement ("BPPA") (Note 16). The depreciation of the asset under finance lease and interest expense on the finance lease obligation are not being fully recovered in current customer rates since these rates only reflect the cash payments required under the BPPA. The annual differences are being deferred as a regulatory asset, which is expected to be recovered from customers in future rates over the term of the lease, which expires in 2056.

(iv) *Generation Early Retirement Costs*
UNS Energy holds an undivided interest in the jointly owned Navajo Generating Station ("Navajo"), located on a site leased from the Navajo Nation with an initial lease term through December 2019. In June 2017 the Navajo Nation approved a land-lease extension that allowed TEP and the co-owners of Navajo to continue operations through December 2019 and begin decommissioning activities thereafter. TEP and the co-owners retired Navajo in November 2019, with related decommissioning activities continuing through 2054, and the capital and operating costs are being recovered through 2030.

UNS Energy owns the Sundt Generating Facility ("Sundt") and was required to retire Sundt Units 1 and 2 in November 2019. Capital and operating costs related to Sundt Units 1 and 2 are being recovered through 2028 and 2030, respectively.

Due to the early retirement of Navajo and Sundt, TEP requested recovery of final retirement costs over a 10-year period in the 2019 general rate application.

(v) *Other Regulatory Assets and Liabilities*
These balances are comprised of regulatory assets and liabilities individually less than $40 million.

(vi) *Energy Efficiency Liability*
The energy efficiency liability primarily relates to Central Hudson's Energy Efficiency Program, established to fund environmental policies associated with energy conservation programs as approved by its regulator.

(vii) *Renewable Energy Surcharge*
Under the ACC's Renewable Energy Standard ("RES"), UNS Energy is required to increase its use of renewable energy each year until it represents at least 15% of its total annual retail energy requirements by 2025. The cost of carrying out the plan is recovered from retail customers through a RES surcharge. Any RES surcharge collections above or below the costs incurred to implement the plans are deferred as a regulatory liability or asset.

The ACC measures RES compliance through Renewable Energy Credits ("REC"). Each REC represents one kilowatt hour generated from renewable resources. When UNS Energy purchases renewable energy, the premium paid above the market cost of conventional power equals the REC recoverable through the RES surcharge. When RECs are purchased, UNS Energy records their cost as long-term other assets (Note 10) with a corresponding regulatory liability to reflect the obligation to use the RECs for future RES compliance. When RECs are reported to the ACC for compliance with RES requirements, energy supply costs and revenue are recognized in an equal amount.

(viii) *Electric and Gas Moderator Account*
Under Central Hudson's 2018 three-year rate order certain regulatory assets and liabilities were approved by the PSC for offset and an electric and gas moderator account was established, which will be used for future customer rate moderation.

Regulatory assets not earning a return: (i) totalled $1,510 million and $1,490 million as at December 31, 2019 and 2018, respectively; (ii) are primarily related to deferred income taxes and employee future benefits; and (iii) generally do not represent a past cash outlay as they are offset by related liabilities that, likewise, do not incur a carrying cost for rate-making purposes. Recovery periods vary or are yet to be determined by the respective regulators.

10. OTHER ASSETS

(in millions)		2019		2018
Supplemental Executive Retirement Plan	$	145	$	143
Renewable Energy Credits (Note 9 *(vii)*)		99		88
Equity investment - Belize Electricity		71		76
Employee future benefits (Note 26)		63		27
Operating leases (Note 16)		46		—
Other investments		43		34
Deferred compensation plan		30		26
Equity Investment - Wataynikaneyap Partnership		12		43
Other [1]		111		115
	$	620	$	552

[1] *Includes the fair value of derivatives (Note 28)*

ITC, UNS Energy and Central Hudson provide additional post-employment benefits through Supplemental Executive Retirement Plans ("SERPs") and deferred compensation plans for Directors and Officers. The assets held to support these plans are reported separately from the related liabilities (Note 17). Most plan assets are held in trust and funded mainly through trust-owned life insurance policies and mutual funds. Assets in mutual and money market funds are recorded at fair value on a recurring basis (Note 28). Included in SERP assets are available-for-sale securities at ITC of $70 million (2018 - $72 million), for which gains and losses are recognized in earnings.

11. PROPERTY, PLANT AND EQUIPMENT

(in millions)		Cost		Accumulated Depreciation		Net Book Value
2019						
Distribution						
Electric [1]	$	11,396	$	(3,125)	$	8,271
Gas		5,277		(1,330)		3,947
Transmission						
Electric		15,207		(3,293)		11,914
Gas		2,267		(681)		1,586
Generation		6,380		(2,472)		3,908
Other		4,042		(1,327)		2,715
Assets under construction		1,329		—		1,329
Land		318		—		318
	$	46,216	$	(12,228)	$	33,988

(in millions)		Cost		Accumulated Depreciation		Net Book Value
2018						
Distribution						
Electric (1)	$	11,000	$	(3,093)	$	7,907
Gas		4,767		(1,244)		3,523
Transmission						
Electric		14,665		(3,212)		11,453
Gas		2,214		(639)		1,575
Generation		6,164		(2,279)		3,885
Other		3,877		(1,251)		2,626
Assets under construction		1,478		—		1,478
Land		310		—		310
	$	44,475	$	(11,718)	$	32,757

(1) *Includes FortisAlberta's deferred operating overhead costs of $121 million (December 31, 2018 - $103 million), representing costs related to the construction of PPE that are deferred for collection in future customer rates over the lives of the related PPE. These costs were reclassified to PPE from long-term regulatory assets to provide greater comparability between subsidiaries.*

Electric distribution assets are those used to distribute electricity at lower voltages (generally below 69 kilovolts ("kV")). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment. Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kilopascals ("kPa")) or a hoop stress of less than 20% of standard minimum yield strength. These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment.

Electric transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires, switching equipment, transformers, support structures and other related equipment. Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher) or a hoop stress of 20% or more of standard minimum yield strength. These assets include transmission stations, telemetry, transmission pipe and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generation stations, gas and combustion turbines, coal-fired generating stations, dams, reservoirs, photovoltaic systems, wind resources and other related equipment.

Other assets include buildings, equipment, vehicles, inventory, information technology assets and the Aitken Creek natural gas storage facility.

As at December 31, 2019 and 2018, assets under construction were primarily associated with ongoing transmission projects at ITC and the addition of gas-fired generating capacity at UNS Energy.

The cost of PPE under finance lease as at December 31, 2019 was $514 million (December 31, 2018 - $656 million) and related accumulated depreciation was $206 million (December 31, 2018 - $203 million) (Note 16).

Jointly Owned Facilities

UNS Energy and ITC hold undivided interests in jointly owned generating facilities and transmission systems, are entitled to their pro rata share of the PPE, and are proportionately liable for the associated operating costs and liabilities. As at December 31, 2019, interests in jointly owned facilities consisted of the following.

(in millions, except as noted)	Ownership %	Cost	Accumulated Depreciation	Net Book Value
San Juan Unit 1	50.0	$ 377	$ (251)	$ 126
Four Corners Units 4 and 5	7.0	234	(100)	134
Luna Energy Facility	33.3	74	(1)	73
Gila River Common Facilities	50.0	105	(35)	70
Springerville Coal Handling Facilities	83.0	270	(117)	153
Transmission Facilities	1.0-80.0	982	(384)	598
		$ 2,042	$ (888)	$ 1,154

12. INTANGIBLE ASSETS

(in millions)	Cost	Accumulated Amortization	Net Book Value
2019			
Computer software	$ 946	$ (576)	$ 370
Land, transmission and water rights	890	(122)	768
Other	115	(61)	54
Assets under construction	68	—	68
	$ 2,019	$ (759)	$ 1,260

(in millions)	Cost	Accumulated Amortization	Net Book Value
2018			
Computer software	$ 860	$ (533)	$ 327
Land, transmission and water rights	855	(125)	730
Other	120	(58)	62
Assets under construction	81	—	81
	$ 1,916	$ (716)	$ 1,200

Included in the cost of land, transmission and water rights as at December 31, 2019 was $133 million (December 31, 2018 - $131 million) not subject to amortization. Amortization expense was $125 million for 2019 (2018 - $106 million). Amortization is estimated to average approximately $77 million for each of the next five years.

13. GOODWILL

(in millions)		2019		2018
Balance, beginning of year	$	12,530	$	11,644
Acquisition of distribution systems by FortisAlberta		1		—
Foreign currency translation impacts [(1)]		(527)		886
Balance, end of year	$	12,004	$	12,530

(1) *Relates to the translation of goodwill associated with the acquisitions of ITC, UNS Energy, Central Hudson, Caribbean Utilities and FortisTCI, whose functional currency is the US dollar*

No goodwill impairment was recognized by the Corporation in 2019 or 2018.

14. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(in millions)		2019		2018
Trade accounts payable	$	754	$	679
Employee compensation and benefits payable		229		193
Dividends payable		228		199
Customer and other deposits		226		267
Gas and fuel cost payable		225		281
Accrued taxes other than income taxes		223		206
Interest payable		212		230
Fair value of derivatives (Note 28)		83		69
Manufactured gas plant site remediation (Note 17)		31		32
Employee future benefits (Note 26)		24		25
Other		143		108
	$	2,378	$	2,289

15. LONG-TERM DEBT

(in millions)	Maturity Date	2019	2018
ITC			
Secured US First Mortgage Bonds -			
4.46% weighted average fixed rate (2018 - 4.51%)	2020-2055	$ **2,624**	$ 2,652
Secured US Senior Notes -			
4.26% weighted average fixed rate (2018 - 4.19%)	2040-2049	**747**	648
Unsecured US Senior Notes -			
3.79% weighted average fixed rate (2018 - 3.91%)	2020-2043	**3,312**	3,751
Unsecured US Shareholder Note -			
6.00% fixed rate (2018 - 6.00%)	2028	**258**	271
Unsecured US Term Loan Credit Agreement -			
2.35% weighted average fixed rate	2021	**260**	—
UNS Energy			
Unsecured US Tax-Exempt Bonds - 4.64% weighted			
average fixed and variable rate (2018 - 4.66%)	2020-2040	**603**	654
Unsecured US Fixed Rate Notes -			
4.38% weighted average fixed rate (2018 - 4.38%)	2021-2048	**1,851**	1,943
Central Hudson			
Unsecured US Promissory Notes - 4.27% weighted			
average fixed and variable rate (2018 - 4.43%)	2020-2059	**986**	938
FortisBC Energy			
Unsecured Debentures -			
4.87% weighted average fixed rate (2018 - 5.03%)	2026-2049	**2,795**	2,595
FortisAlberta			
Unsecured Debentures -			
4.64% weighted average fixed rate (2018 - 4.64%)	2024-2052	**2,185**	2,185
FortisBC Electric			
Secured Debentures -			
8.80% fixed rate (2018 - 8.80%)	2023	**25**	25
Unsecured Debentures -			
5.05% weighted average fixed rate (2018 - 5.05%)	2021-2050	**710**	710
Other Electric			
Secured First Mortgage Sinking Fund Bonds -			
6.14% weighted average fixed rate (2018 - 6.14%)	2020-2057	**571**	578
Secured First Mortgage Bonds -			
5.66% weighted average fixed rate (2018 - 5.66%)	2025-2061	**220**	220
Unsecured Senior Notes -			
4.45% weighted average fixed rate (2018 - 4.45%)	2041-2048	**152**	152
Unsecured US Senior Loan Notes and Bonds - 4.53% weighted			
average fixed and variable rate (2018 - 4.76%)	2020-2049	**645**	584
Corporate			
Unsecured US Senior Notes and Promissory Notes -			
3.80% weighted average fixed rate (2018 - 3.41%)	2020-2044	**2,903**	4,398
Unsecured Debentures -			
6.50% fixed rate (2018 - 6.50%)	2039	**200**	200
Unsecured Senior Notes - 2.85% fixed rate (2018 - 2.85%)	2023	**500**	500
Long-term classification of credit facility borrowings		**640**	1,066
Fair value adjustment - ITC acquisition		**133**	161
Total long-term debt (Note 28)		**22,320**	24,231
Less: Deferred financing costs and debt discounts		**(129)**	(146)
Less: Current installments of long-term debt		**(690)**	(926)
		$ **21,501**	$ 23,159

Most long-term debt at the Corporation's regulated utilities is redeemable at the option of the respective utility at the greater of par or a specified price, together with accrued and unpaid interest. Security, if provided, is typically through a fixed or floating first charge on specific assets of the utility.

The Corporation's unsecured debentures and senior notes are redeemable at the option of Fortis at the greater of par or a specified price together with accrued and unpaid interest.

Certain long-term debt at the Corporation have covenants that (i) restrict the issuance of additional debt such that the consolidated debt to consolidated capitalization ratio does not exceed 70% at any time, and (ii) provide that the Corporation shall not declare, pay or make any dividends or any other restricted payments if, immediately thereafter, its consolidated debt to consolidated capitalization ratio would exceed 65%.

Long-Term Debt Issuances

(in millions, except %)	Month Issued	Interest Rate *(%)*	Maturity		Amount	Use of Proceeds
ITC						
Secured notes	January	4.55	2049	US	50	(1) (2) (3)
Unsecured term loan credit agreement (4)	June	(5)	2021	US	200	(6)
Secured notes	July	4.65	2049	US	50	(1) (2) (3)
First mortgage bonds	August	3.30	2049	US	75	(1) (2) (3)
Central Hudson						
Unsecured notes	October	3.89	2049	US	50	(2) (3) (6)
Unsecured notes	October	3.99	2059	US	50	(2) (3) (6)
FortisBC Energy						
Unsecured debentures	August	2.82	2049		200	(1)
FortisTCI						
Unsecured non-revolving term loan	February	(7)	2025	US	5	(2) (3)
Caribbean Utilities						
Unsecured notes	May	4.14	2049	US	40	(1) (3) (6)
Unsecured notes	August	4.14	2049	US	20	(2) (3) (6)
Unsecured notes	August	3.83	2039	US	20	(2) (3) (6)

(1) *Repay credit facility borrowings*
(2) *Finance capital expenditures*
(3) *General corporate purposes*
(4) *Maximum amount of borrowings under this agreement is US$400 million; in January 2020 the remaining US$200 million was drawn to repay outstanding commercial paper balances*
(5) *Floating rate of a one-month LIBOR plus a spread of 0.60%*
(6) *Repay maturing long-term debt*
(7) *Floating rate of a one-month LIBOR plus a spread of 1.75%*

Fortis used the proceeds from the disposition of the Waneta Expansion (Note 23) to repay credit facility borrowings and repurchase, via a tender offer, US$400 million of its outstanding 3.055% unsecured senior notes due in 2026. A gain on the repayment of debt of $11 million ($7 million after tax), net of expenses, was recognized in other income, net (Note 24).

Fortis used the proceeds from the issuance of common shares (Note 18) to redeem the US$500 million, 2.10% unsecured notes that were due in 2021, to repay credit facility borrowings, and for general corporate purposes.

In January 2020 ITC entered into an unsecured term loan credit agreement, due in January 2021, under which the maximum amount of US$75 million was borrowed. The proceeds were used to repay credit facility borrowings.

Long-Term Debt Repayments

The consolidated requirements to meet principal repayments and maturities in each of the next five years and thereafter are as follows.

(year)	**Total** *(in millions)*
2020	$ 690
2021	872
2022	1,146
2023	1,553
2024	1,106
Thereafter	16,953
	$ 22,320

Credit Facilities

As at December 31, 2019, the Corporation and its subsidiaries had consolidated credit facilities of approximately $5.6 billion, of which approximately $4.3 billion was unused, including $1.3 billion unused under the Corporation's committed revolving corporate credit facility.

The following summarizes the credit facilities of the Corporation and its subsidiaries.

(in millions)	Regulated Utilities	Corporate and Other	**2019**	2018
Total credit facilities	$ 4,209	$ 1,381	**$ 5,590**	$ 5,165
Credit facilities utilized:				
Short-term borrowings [(1)]	(512)	—	**(512)**	(60)
Long-term debt (including current portion) [(2)]	(640)	—	**(640)**	(1,066)
Letters of credit outstanding	(64)	(50)	**(114)**	(119)
Credit facilities unutilized	$ 2,993	$ 1,331	**$ 4,324**	$ 3,920

(1) *The weighted average interest rate was approximately 3.2% (December 31, 2018 - 4.2%).*
(2) *The weighted average interest rate was approximately 2.4% (December 31, 2018 - 3.3%). The current portion was $252 million (December 31, 2018 - $735 million).*

Credit facilities are syndicated primarily with large banks in Canada and the United States, with no one bank holding more than 20% of the total facilities. Approximately $5.1 billion of the total credit facilities are committed facilities with maturities ranging from 2020-2024.

Consolidated credit facilities of approximately $5.6 billion as at December 31, 2019 are itemized below.

(in millions)		**Amount**	**Maturity**
Unsecured committed revolving credit facilities			
Regulated utilities			
ITC [(1)]	US	900	October 2022
UNS Energy	US	500	October 2022
Central Hudson	US	250	[(2)]
FortisBC Energy		700	August 2024
FortisAlberta		250	August 2024
FortisBC Electric		150	April 2024
Other Electric		190	[(3)]
Other Electric [(4)]	US	50	January 2020
Corporate and Other		1,350	[(5)]
Other facilities			
UNS Energy - unsecured non-revolving facility	US	225	December 2020
Central Hudson - uncommitted credit facility	US	40	n/a
FortisBC Electric - unsecured demand overdraft facility		10	n/a
Other Electric - unsecured demand facilities		20	n/a
Other Electric - unsecured demand facility and emergency standby loan	US	60	April 2020
Corporate and Other - unsecured non-revolving facility		31	n/a

(1) *ITC also has a US$400 million commercial paper program, under which US$200 million was outstanding as at December 31, 2019, which is reported in short-term borrowings.*
(2) *US$50 million in July 2020 and US$200 million in October 2020*
(3) *$40 million in June 2021, $50 million in February 2022 and $100 million in August 2024*
(4) *Subsequent to year end, facility was increased to US$70 million and the maturity date extended to January 2025*
(5) *$50 million in April 2022 and $1.3 billion in July 2024 with the option to increase by an amount up to $500 million*

16. LEASES

The Corporation and its subsidiaries lease office facilities, utility equipment, land, and communication tower space with remaining terms of up to 22 years, with optional renewal terms. Certain lease agreements include rental payments adjusted periodically for inflation or require the payment of real estate taxes, insurance, maintenance, or other operating expenses associated with the lease premises.

The Corporation's subsidiaries also have finance leases related to generating facilities with remaining terms of up to 36 years.

Leases were presented on the consolidated balance sheet as follows.

(in millions)		2019
Operating leases		
Other assets	$	46
Accounts payable and other current liabilities		(8)
Other liabilities		(38)
Finance leases [(1)] [(2)] [(3)]		
Regulatory assets	$	116
PPE, net		308
Current installments of finance leases		(24)
Finance leases		(413)

(1) *FortisBC Electric has a finance lease for the BPPA (Note 9 (iii)), which relates to the sale of the output of the Brilliant hydroelectric plant, and for the Brilliant Terminal Station ("BTS"), which relates to the use of the station. Both agreements expire in 2056. In exchange for the specified take-or-pay amounts of power, the BPPA requires semi-annual payments based on a return on capital, which includes the original and ongoing capital cost, and related variable power purchase costs. The BTS requires semi-annual payments based on a charge related to the recovery of the capital cost of the BTS, and related variable operating costs.*

(2) *TEP is party to two Springerville Common Facilities leases with fixed purchase options and initial terms to January 2021. During 2019 TEP exercised its option to purchase a 32.2% undivided interest in the Springerville Common Facilities by January 2021 for $88 million.*

(3) *In December 2019 TEP exercised its option to purchase Gila River Unit 2 for $212 million.*

The components of lease expense were as follows.

(in millions)		2019
Operating lease cost	$	10
Finance lease cost:		
Amortization		17
Interest		48
Variable lease cost		39
Total lease cost	$	114

Operating lease cost in 2018 was $10 million.

As at December 31, 2019, the present value of minimum lease payments was as follows.

(in millions)		Operating Leases		Finance Leases		Total
2020	$	10	$	56	$	66
2021		8		121		129
2022		7		33		40
2023		6		33		39
2024		4		33		37
Thereafter		22		1,083		1,105
		57		1,359		1,416
Less: Imputed interest		(11)		(922)		(933)
Total lease obligations		46		437		483
Less: Current installments		(8)		(24)		(32)
	$	38	$	413	$	451

As at December 31, 2018, the present value of minimum lease payments was as follows.

(year)	**Total** *(in millions)*
2019	$ 313
2020	77
2021	80
2022	49
2023	47
Thereafter	1,885
	2,451
Less: Imputed interest and executory costs	(1,809)
Total capital lease and finance obligations	642
Less: Current installments	(252)
	$ 390

Supplemental lease information was as follows.

(in millions, except as indicated)	**2019**
Weighted average remaining lease term *(years)*	
Operating leases	**10**
Finance leases	**27**
Weighted average discount rate *(%)*	
Operating leases	**4.1**
Finance leases	**4.8**
Cash payments related to lease liabilities	
Operating cash flows used for operating leases	**$ (10)**
Operating cash flows used for finance leases	**(47)**
Financing cash flows used for finance leases	**(16)**
Investing cash flows used for finance leases	**(212)**

See Note 27 for non-cash transactions that resulted in right-of-use assets obtained in exchange for new lease liabilities.

17. OTHER LIABILITIES

(in millions)	**2019**	2018
Employee future benefits (Note 26)	**$ 832**	$ 741
AROs (Note 3)	**148**	111
Stock-based compensation plans (Note 22)	**83**	56
Customer and other deposits	**70**	57
Fair value of derivatives (Note 28)	**68**	30
Manufactured gas plant site remediation *(i)*	**48**	32
Mine reclamation obligations *(ii)*	**43**	40
Operating leases	**38**	—
Finance obligations *(iii)*	**38**	—
Deferred compensation plan (Note 10)	**33**	29
Other	**45**	42
	$ 1,446	$ 1,138

(i) Environmental regulations require Central Hudson to investigate sites at which the Company or its predecessors once owned and/or operated manufactured gas plants and, if necessary, remediate those sites. Costs are accrued based on the amounts that can be reasonably estimated. As at December 31, 2019, an obligation of $74 million (US$57 million) was recognized, including a current portion of $26 million (US$20 million) recognized in accounts payable and other current liabilities (Note 14). Central Hudson has notified its insurers that it intends to seek reimbursement where insurance coverage exists. Differences between actual costs and the associated rate allowances are deferred as a regulatory asset for future recovery (Note 9).

(ii) TEP pays ongoing reclamation costs related to two coal mines that supply generating facilities in which it has an ownership interest but does not operate. Costs are deferred as a regulatory asset and recovered from customers as permitted by the regulator. TEP's share of the reclamation costs is estimated to be $74 million (US$57 million) upon expiry of the coal agreements between 2022 and 2031. The present value of the estimated future liability is shown in the table above.

(iii) Between 2000 and 2005 FortisBC Energy entered into arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by FortisBC Energy. These assets are integral equipment to real estate assets and the transactions have been accounted for as finance transactions, with the proceeds thereof recognized as finance obligations. Lease payments, net of the portion recognized as interest expense, reduce the finance obligations. The finance obligations have implicit interest rates ranging from 6.9% to 7.25% and are being repaid over an initial 35-year period with an early termination option after 17 years. If the Company exercises this option, it would pay the municipality an early termination payment equal to the carrying value of the obligation at termination. In November 2019 and October 2018, FortisBC Energy exercised early termination payment options in the amount of $12 million and $27 million, respectively, on two of these arrangements.

18. COMMON SHARES

During 2019 the Corporation issued approximately 4.1 million common shares under its at-the-market common equity program at an average price of $52.16 per share. The gross proceeds of $212 million ($209 million net of commissions) were used primarily to fund capital expenditures.

Also during 2019 the Corporation issued approximately 22.8 million common shares representing gross proceeds of $1,190 million ($1,167 million net of commissions) at a price of $52.15 per share. The net proceeds were used to redeem US$500 million of its outstanding 2.10% unsecured notes due on October 4, 2021, to repay credit facility borrowings, and for general corporate purposes.

19. EARNINGS PER COMMON SHARE

Diluted earnings per share ("EPS") was calculated using the treasury stock method for options.

	2019			2018		
	Net Earnings to Common Shareholders *($ millions)*	**Weighted Average Shares** *(# millions)*	**EPS** *($)*	Net Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(# millions)*	EPS *($)*
Basic EPS	**$ 1,655**	**436.8**	**$ 3.79**	$ 1,100	424.7	$ 2.59
Potential dilutive effect of stock options	**—**	**0.7**	**—**	—	0.5	—
Diluted EPS	**$ 1,655**	**437.5**	**$ 3.78**	$ 1,100	425.2	$ 2.59

20. PREFERENCE SHARES

Authorized

An unlimited number of first preference shares and second preference shares, without nominal or par value.

Issued and outstanding	**2019**			2018		
First Preference Shares	**Number of Shares *(in thousands)***		**Amount *(in millions)***	Number of Shares *(in thousands)*		Amount *(in millions)*
Series F	**5,000**	**$**	**122**	5,000	$	122
Series G	**9,200**		**225**	9,200		225
Series H	**7,025**		**172**	7,025		172
Series I	**2,975**		**73**	2,975		73
Series J	**8,000**		**196**	8,000		196
Series K	**10,000**		**244**	10,000		244
Series M	**24,000**		**591**	24,000		591
	66,200	**$**	**1,623**	66,200	$	1,623

Characteristics of the first preference shares are as follows.

First Preference Shares [(1)] [(2)]	**Initial Yield** *(%)*	**Annual Dividend** *($)*	**Reset Dividend Yield** *(%)*	**Earliest Redemption and/or Conversion Option Date**	**Redemption Value** *($)*	**Right to Convert on a One-For-One Basis**
Perpetual fixed rate						
Series F	4.90	1.2250	—	December 1, 2011	25.00	—
Series J [(3)]	4.75	1.1875	—	December 1, 2017	25.50	—
Fixed rate reset [(4)] [(5)]						
Series G	5.25	1.0983	2.13	September 1, 2013	25.00	—
Series H	4.25	0.6250	1.45	June 1, 2015	25.00	Series I
Series K [(6)]	4.00	0.9823	2.05	March 1, 2019	25.00	Series L
Series M [(7)]	4.10	0.9783	2.48	December 1, 2019	25.00	Series N
Floating rate reset [(5)] [(8)]						
Series I [(3)]	2.10	—	1.45	June 1, 2015	25.50	Series H
Series L	—	—	2.05	March 1, 2024	—	Series K
Series N	—	—	2.48	December 1, 2024	—	Series M

(1) *Holders are entitled to receive a fixed or floating cumulative quarterly cash dividend as and when declared by the Board of Directors of the Corporation, payable in equal installments on the first day of each quarter.*

(2) *On or after the specified redemption dates, the Corporation has the option to redeem for cash the outstanding first preference shares, in whole or in part, at the specified per share redemption value plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption, and in the case of the first preference shares that reset, on every fifth anniversary date thereafter.*

(3) *First Preference Shares, Series J were redeemable at $26.00 until December 1, 2018, decreasing by $0.25 each year until December 1, 2021 and redeemable at $25.00 per share thereafter. First Preference Shares, Series I are redeemable at $25.50 per share, up to but excluding June 1, 2020, and at $25.00 per share on June 1, 2020, and on every fifth anniversary date thereafter.*

(4) *On the redemption and/or conversion option date, and each five-year anniversary thereafter, the reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus the applicable reset dividend yield.*

(5) *On each conversion option date, the holders have the option, subject to certain conditions, to convert any or all of their shares into an equal number of Cumulative Redeemable first preference shares of a specified series.*

(6) *The annual dividend per share for the First Preference Shares, Series K was reset from $1.0000 to $0.9823 for the five-year period from March 1, 2019 up to but excluding March 1, 2024.*

(7) *The annual dividend per share for the First Preference Shares, Series M was reset from $1.0250 to $0.9783 for the five-year period from December 1, 2019 up to but excluding December 1, 2024.*

(8) *The floating quarterly dividend rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus the applicable reset dividend yield.*

On the liquidation, dissolution or winding-up of Fortis, holders of common shares are entitled to participate ratably in any distribution of assets of Fortis, subject to the rights of holders of first and second preference shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution, in priority to or ratably with the holders of the common shares.

21. ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)	Opening Balance	Net Change	Ending Balance
2019			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	**$ 1,470**	**$ (757)**	**$ 713**
Hedges of net investments in foreign operations	**(544)**	**185**	**(359)**
Income tax recovery (expense)	**10**	**(13)**	**(3)**
	936	**(585)**	**351**
Other			
Cash flow hedges (Note 28)	**11**	**6**	**17**
Unrealized employee future benefits losses (Note 26)	**(20)**	**(18)**	**(38)**
Income tax recovery	**1**	**5**	**6**
	(8)	**(7)**	**(15)**
Accumulated other comprehensive income	**$ 928**	**$ (592)**	**$ 336**
2018			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	$ 247	$ 1,223	$ 1,470
Hedges of net investments in foreign operations	(172)	(372)	(544)
Income tax (expense) recovery	(1)	11	10
	74	862	936
Other			
Cash flow hedges (Note 28)	10	1	11
Unrealized employee future benefits (losses) gains (Note 26)	(26)	6	(20)
Income tax recovery (expense)	3	(2)	1
	(13)	5	(8)
Accumulated other comprehensive income	$ 61	$ 867	$ 928

22. STOCK-BASED COMPENSATION PLANS

Stock Options

Officers and certain key employees of Fortis and its subsidiaries are eligible for grants of options to purchase common shares of the Corporation. Options are exercisable for a period of 10 years from the grant date, expire no later than three years after the termination, death or retirement of the optionee, and vest evenly over a four-year period on each anniversary of the grant date.

The following options were granted in 2019 and 2018.

	2019	2018	
	February	February	March
Options granted *(# in thousands)*	**852**	722	40
Exercise price *($)* (1)	**47.57**	41.27	42.00
Grant date fair value *($)*	**3.70**	3.43	4.08
Valuation assumptions:			
Dividend yield *(%)* (2)	**3.8**	3.7	3.7
Expected volatility *(%)* (3)	**15.2**	15.5	15.7
Risk-free interest rate *(%)* (4)	**1.8**	2.1	2.0
Weighted average expected life *(years)* (5)	**5.6**	5.6	5.6

(1) *Five-day VWAP immediately preceding the grant date*
(2) *Reflects average annual dividend yield up to the grant date and the weighted average expected life of the options*
(3) *Reflects historical experience over a period equal to the weighted average expected life of the options*
(4) *Government of Canada benchmark bond yield at the grant date that covers the weighted average expected life of the options*
(5) *Reflects historical experience*

The following table summarizes information related to stock options for 2019.

	Total Options		**Non-vested Options** (1)	
(in thousands, except as indicated)	**Number of Options**	**Weighted Average Exercise Price**	**Number of Options**	**Weighted Average Grant Date Fair Value**
Options outstanding, January 1, 2019	**4,015**	**$ 37.73**	**1,771**	**$ 3.10**
Granted	**852**	**$ 47.57**	**852**	**$ 3.70**
Exercised	**(1,449)**	**$ 35.36**	**n/a**	**n/a**
Vested	**n/a**	**n/a**	**(713)**	**$ 2.92**
Cancelled/Forfeited	**—**	**n/a**	**—**	**n/a**
Options outstanding, December 31, 2019	**3,418**	**$ 41.18**	**1,910**	**$ 3.43**
Options vested, December 31, 2019 (2)	**1,508**	**$ 37.69**		

(1) *As at December 31, 2019, there was $7 million of unrecognized compensation expense related to stock options not yet vested, which is expected to be recognized over a weighted average period of approximately three years.*
(2) *As at December 31, 2019, the weighted average remaining term of vested options was six years with an aggregate intrinsic value of $24 million.*

The following table summarizes additional stock option information.

(in millions)	**2019**	2018
Stock option expense recognized	**$ 2**	$ 2
Stock options exercised:		
Cash received for exercise price	**51**	12
Intrinsic value realized by employees	**22**	3
Fair value of options that vested	**2**	2

Directors' DSU Plan

Directors of the Corporation who are not officers are eligible for grants of DSUs representing the equity portion of their annual compensation. Directors can further elect to receive credit for their quarterly cash retainer in a notional account of DSUs in lieu of cash. The Corporation may also determine that special circumstances justify the grant of additional DSUs to a director.

Each DSU vests at the grant date, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash.

The following table summarizes information related to DSUs.

	2019	2018
Number of units *(in thousands)*		
Beginning of year	177	185
Granted	29	32
Notional dividends reinvested	6	8
Paid out	(47)	(48)
End of year	165	177
Additional information *(in millions)*		
Compensation expense recognized	$ 3	$ 2
Cash payout [(1)]	2	2
Accrued liability as at December 31 [(2)]	9	8

(1) *Reflects a weighted average payout price of $51.76 per DSU (2018 - $43.15)*
(2) *Recognized at the respective December 31st VWAP (Note 3) and included in long-term other liabilities (Note 17)*

PSU Plans

Senior management of the Corporation and its subsidiaries, and all ITC employees, are eligible for grants of PSUs representing a component of their long-term compensation.

Each PSU vests over a three-year period or immediately upon retirement eligibility of the holder, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash. At the end of the three-year vesting period, cash payouts are the product of: (i) the numbers of units vested; (ii) the VWAP of the Corporation's common shares for the five trading days prior to the maturity date; and (iii) a payout percentage that may range from 0% to 200%.

The payout percentage is based on the Corporation's performance over the three-year vesting period, mainly determined by: (i) the Corporation's total shareholder return as compared to a predefined peer group of companies; and (ii) the Corporation's cumulative EPS, or for certain subsidiaries the Company's cumulative net income, as compared to the target established at the time of the grant.

The following table summarizes information related to PSUs.

		2019		2018
Number of units *(in thousands)*				
Beginning of year		**1,763**		1,351
Granted		**690**		669
Notional dividends reinvested		**73**		66
Paid out		**(357)**		(281)
Cancelled/forfeited		**(51)**		(42)
End of year		**2,118**		1,763
Additional information *(in millions)*				
Compensation expense recognized	**$**	**74**	$	22
Compensation expense unrecognized (1)		**35**		27
Cash payout (2)		**16**		14
Accrued liability as at December 31 (3)		**106**		50
Aggregate intrinsic value as at December 31 (4)		**141**		77

(1) *Relates to unvested PSUs and is expected to be recognized over a weighted average period of two years*
(2) *Reflects a weighted average payout price of $45.14 per PSU and a payout percentage of 101% (2018 - $46.01 and 109% respectively)*
(3) *Recognized at the respective December 31st VWAP (Note 3) and included in accounts payable and other current liabilities and in long-term other liabilities (Notes 14 and 17)*
(4) *Relates to outstanding PSUs and reflects a weighted average contractual life of one year*

RSU Plans

Senior management of the Corporation and its subsidiaries, and all ITC employees, are eligible for grants of RSUs representing a component of their long-term compensation.

Each RSU vests over a three-year period or immediately upon retirement eligibility of the holder, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash.

The following table summarizes information related to RSUs.

		2019		2018
Number of units *(in thousands)*				
Beginning of year		**717**		483
Granted		**429**		305
Notional dividends reinvested		**35**		26
Paid out		**(92)**		(75)
Cancelled/forfeited		**(39)**		(22)
End of year		**1,050**		717
Additional information *(in millions)*				
Compensation expense recognized	**$**	**24**	$	11
Compensation expense unrecognized (1)		**17**		15
Cash payout (2)		**4**		3
Accrued liability as at December 31 (3)		**39**		19
Aggregate intrinsic value as at December 31 (4)		**56**		34

(1) *Relates to unvested RSUs and is expected to be recognized over a weighted average period of two years*
(2) *Reflects a weighted average payout price of $45.83 per RSU (2018 - $45.55)*
(3) *Recognized at the respective December 31st VWAP (Note 3) and included in accounts payable and other current liabilities and in long-term other liabilities (Notes 14 and 17)*
(4) *Relates to outstanding RSUs and reflects a weighted average contractual life of one year*

23. DISPOSITION

On April 16, 2019, Fortis sold its 51% ownership interest in the 335-megawatt Waneta Expansion for proceeds of $995 million. A gain on disposition of $577 million ($484 million after tax), net of expenses, was recognized in the Corporate and Other segment, and the related non-controlling interest has been removed from equity. Refer to Note 15 for use of proceeds.

Up to the date of disposition, the Waneta Expansion contributed $17 million to earnings before income tax expense, excluding the gain on disposition (December 31, 2018 - $54 million), of which Fortis' share was 51%.

24. OTHER INCOME, NET

(in millions)	**2019**	2018
Equity component of AFUDC	**$ 74**	$ 64
Derivative gains (losses)	**17**	(12)
Interest income	**16**	15
Gain on repayment of debt (Note 15)	**11**	—
Other	**20**	(7)
	$ 138	$ 60

25. INCOME TAXES

Deferred Income Tax Assets and Liabilities

The significant components of deferred income tax assets and liabilities consisted of the following.

(in millions)	**2019**	2018
Gross deferred income tax assets		
Regulatory liabilities	**$ 588**	$ 635
Tax loss and credit carryforwards	**532**	522
Employee future benefits	**165**	153
Unrealized foreign exchange losses on long-term debt	**40**	69
Other	**88**	76
	1,413	1,455
Valuation allowance	**(22)**	(56)
Net deferred income tax asset	**$ 1,391**	$ 1,399
Gross deferred income tax liabilities		
PPE	**$ (3,986)**	$ (3,780)
Regulatory assets	**(269)**	(203)
Intangible assets	**(105)**	(102)
	(4,360)	(4,085)
Net deferred income tax liability	**$ (2,969)**	$ (2,686)

The deferred income tax assets associated with unrealized foreign exchange losses on long-term debt reflect $22 million of unrealized capital losses as at December 31, 2019 (December 31, 2018 - $56 million). These deferred income tax assets can only be utilized if the Corporation has capital gains to offset these losses once realized. Management believes that it is "more likely than not" that Fortis will not be able to generate sufficient future capital gains and, consequently, the Corporation recognized a valuation allowance.

Management believes that, based on its historical pattern of taxable income, Fortis will produce the necessary income in the future to realize all other deferred income tax assets.

Unrecognized Tax Benefits

(in millions)	**2019**	2018
Beginning of year	**$ 38**	$ 28
Additions related to current year	**5**	6
Adjustments related to prior years	**(7)**	4
End of year	**$ 36**	$ 38

Unrecognized tax benefits, if recognized, would reduce income tax expense by $1 million in 2019. Fortis has not recognized interest expense in 2019 and 2018 related to unrecognized tax benefits.

Income Tax Expense

(in millions)	**2019**	2018
Canadian		
Earnings before income tax expense	**$ 901**	$ 376
Current income tax	**49**	51
Deferred income tax	**42**	(25)
Total Canadian	**$ 91**	$ 26
Foreign		
Earnings before income tax expense	**$ 1,240**	$ 1,075
Current income tax	**(7)**	(22)
Deferred income tax	**205**	161
Total Foreign	**$ 198**	$ 139
Income tax expense	**$ 289**	$ 165

Income tax expense differs from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory income tax rate to earnings before income tax expense.

The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

(in millions, except %)	**2019**	2018
Earnings before income tax expense	**$ 2,141**	$ 1,451
Combined Canadian federal and provincial statutory income tax rate	**28.5 %**	28.5 %
Expected federal and provincial taxes at statutory rate	**$ 610**	$ 414
Decrease resulting from:		
Foreign and other statutory rate differentials	**(124)**	(110)
Difference between gain on sale for accounting and amounts calculated for tax purposes	**(73)**	—
Release of Valuation Allowance	**(33)**	(16)
Remeasurement of deferred tax liabilities	**—**	(44)
AFUDC	**(16)**	(14)
Effects of rate-regulated accounting:		
Difference between depreciation claimed for income tax and accounting purposes	**(48)**	(34)
Items capitalized for accounting purposes but expensed for income tax purposes	**(17)**	(21)
Other	**(10)**	(10)
Income tax expense	**$ 289**	$ 165
Effective tax rate	**13.5 %**	11.4 %

Income Tax Carryforwards

(in millions)	Expiring Year	**2019**
Canadian		
Capital loss	n/a	**$ 19**
Non-capital loss	2028-2039	**110**
Other tax credits	2026-2038	**2**
		131
Unrecognized		**(14)**
		117
Foreign		
Federal and state net operating loss	2020-2039	**2,929**
Other tax credits	2023-2039	**74**
		3,003
Total income tax carryforwards recognized as at December 31		**$ 3,120**

The Corporation and certain of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential income tax compliance examinations include the United States (Federal, Arizona, Kansas, Iowa, Michigan, Minnesota and New York) and Canada (Federal and British Columbia). The Corporation's 2013 to 2019 taxation years are still open for audit in Canadian jurisdictions and its 2016 to 2019 taxation years are still open for audit in United States jurisdictions.

26. EMPLOYEE FUTURE BENEFITS

For defined benefit pension and OPEB plans, the benefit obligation and fair value of plan assets are measured as at December 31.

For the Corporation's Canadian and Caribbean subsidiaries, actuarial valuations to determine funding contributions for pension plans are required at least every three years. The most recent valuations were as of December 31, 2016 for FortisBC Electric and FortisBC Energy (plans covering unionized employees); December 31, 2017 for Newfoundland Power, FortisAlberta, FortisOntario and the Corporation; December 31, 2018 for FortisBC Energy (plan covering non-unionized employees); and December 31, 2019 for Caribbean Utilities.

ITC, UNS Energy and Central Hudson perform annual actuarial valuations as their funding requirements are based on maintaining minimum annual targets, all of which have been met.

The Corporation's investment policy is to ensure that the defined benefit pension and OPEB plan assets, together with expected contributions, are invested in a prudent and cost-effective manner to optimally meet the liabilities of the plans. The investment objective is to maximize returns in order to manage the funded status of the plans and minimize the Corporation's cost over the long term, as measured by both cash contributions and recognized expense.

Allocation of Plan Assets as at December 31

(weighted average %)	**2019 Target Allocation**	**2019**	2018
Equities	**46**	**47**	45
Fixed income	**47**	**46**	47
Real estate	**6**	**6**	7
Cash and other	**1**	**1**	1
	100	**100**	100

Fair Value of Plan Assets as at December 31

(in millions)	**Level 1 (1)**	**Level 2 (1)**	**Level 3 (1)**	**Total**
2019				
Equities	**$ 622**	**$ 1,050**	**$ —**	**$ 1,672**
Fixed income	**171**	**1,445**	**—**	**1,616**
Real estate	**—**	**16**	**207**	**223**
Private equities	**—**	**—**	**22**	**22**
Cash and other	**8**	**10**	**—**	**18**
	$ 801	**$ 2,521**	**$ 229**	**$ 3,551**
2018				
Equities	$ 508	$ 885	$ —	$ 1,393
Fixed income	144	1,338	—	1,482
Real estate	—	14	190	204
Private equities	—	—	25	25
Cash and other	8	11	—	19
	$ 660	$ 2,248	$ 215	$ 3,123

(1) *Refer to Note 28 for a description of the fair value hierarchy.*

The following table reconciles the changes in the fair value of plan assets that have been measured using Level 3 inputs.

(in millions)	**2019**	2018
Balance, beginning of year	**$ 215**	$ 190
Return on plan assets	**19**	15
Foreign currency translation	**(2)**	3
Purchases, sales and settlements	**(3)**	7
Balance, end of year	**$ 229**	$ 215

Funded Status	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2019**	2018	**2019**	2018
Change in benefit obligation [(1)]				
Balance, beginning of year	**$ 3,207**	$ 3,215	**$ 655**	$ 665
Service costs	**77**	84	**27**	31
Employee contributions	**16**	16	**2**	2
Interest costs	**124**	114	**25**	23
Benefits paid	**(144)**	(145)	**(27)**	(26)
Actuarial losses (gains)	**439**	(217)	**46**	(69)
Past service costs (credits)/plan amendments	**1**	(1)	**4**	(3)
Foreign currency translation	**(88)**	141	**(20)**	32
Balance, end of year [(2) (3)]	**$ 3,632**	$ 3,207	**$ 712**	$ 655
Change in value of plan assets				
Balance, beginning of year	**$ 2,830**	$ 2,841	**$ 293**	$ 277
Actual return on plan assets	**523**	(93)	**62**	(13)
Benefits paid	**(138)**	(137)	**(27)**	(26)
Employee contributions	**18**	16	**2**	2
Employer contributions	**53**	79	**28**	29
Foreign currency translation	**(78)**	124	**(15)**	24
Balance, end of year [(4)]	**$ 3,208**	$ 2,830	**$ 343**	$ 293
Funded status	**$ (424)**	$ (377)	**$ (369)**	$ (362)
Balance sheet presentation				
Long-term assets (Note 10)	**$ 46**	$ 26	**$ 17**	$ 1
Current liabilities (Note 14)	**(12)**	(12)	**(12)**	(13)
Long-term liabilities (Note 17)	**(458)**	(391)	**(374)**	(350)
	$ (424)	$ (377)	**$ (369)**	$ (362)

(1) *Amounts reflect projected benefit obligation for defined benefit pension plans and accumulated benefit obligation for OPEB plans.*

(2) *The accumulated benefit obligation, which excludes assumptions about future salary levels, for defined benefit pension plans was $3,352 million (2018 - $2,936 million).*

(3) *The increases in the defined benefit pension and OPEB obligations were driven by the decrease in discount rates due to lower interest rates.*

(4) *The increases in the defined benefit pension and OPEB plan assets were driven by favourable market returns, largely related to the performance of equity investments during the year.*

For those defined benefit pension plans for which the projected benefit obligation exceeded the fair value of plan assets as at December 31, 2019, the obligation was $2,971 million compared to plan assets of $2,511 million, respectively (December 31, 2018 - $2,600 million and $2,207 million, respectively).

For those defined benefit pension plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2019, the obligation was $2,752 million compared to plan assets of $2,478 million, respectively (December 31, 2018 - $2,185 million and $1,940 million, respectively).

For those OPEB plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2019, the obligation was $537 million compared to plan assets of $151 million, respectively (December 31, 2018 - $486 million and $123 million, respectively).

Net Benefit Cost [1]	**Defined Benefit Pension Plans**		**OPEB Plans**	
(in millions)	**2019**	2018	**2019**	2018
Service costs	**$ 77**	$ 84	**$ 27**	$ 31
Interest costs	**124**	114	**25**	23
Expected return on plan assets	**(161)**	(162)	**(16)**	(16)
Amortization of actuarial losses (gains)	**24**	48	**(4)**	—
Amortization of past service credits/plan amendments	**(1)**	—	**(7)**	(10)
Regulatory adjustments	**2**	(1)	**3**	6
Net benefit cost	**$ 65**	$ 83	**$ 28**	$ 34

[1] *The non-service cost components of net periodic benefit cost are included in other income, net on the consolidated statements of earnings.*

The following table summarizes the accumulated amounts of net benefit cost that have not yet been recognized in earnings or comprehensive income and shows their classification on the consolidated balance sheets.

	Defined Benefit Pension Plans		**OPEB Plans**	
(in millions)	**2019**	2018	**2019**	2018
Unamortized net actuarial losses (gains)	**$ 32**	$ 19	**$ (2)**	$ (2)
Unamortized past service costs	**1**	1	**7**	2
Income tax recovery	**(8)**	(3)	**(1)**	(1)
Accumulated other comprehensive income (loss) (Note 21)	**$ 25**	$ 17	**$ 4**	$ (1)
Net actuarial losses (gains)	**$ 486**	$ 457	**$ (18)**	$ (25)
Past service credits	**(9)**	(10)	**(8)**	(16)
Other regulatory deferrals	**15**	15	**19**	27
	$ 492	$ 462	**$ (7)**	$ (14)
Regulatory assets (Note 9)	**$ 492**	$ 462	**$ 38**	$ 23
Regulatory liabilities (Note 9)	**—**	—	**(45)**	(37)
Net regulatory assets (liabilities)	**$ 492**	$ 462	**$ (7)**	$ (14)

The following table summarizes the components of net benefit cost recognized in comprehensive income or as regulatory assets, which would otherwise have been recognized in comprehensive income.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2019**	2018	**2019**	2018
Current year net actuarial losses (gains)	**$ 11**	$ (3)	**$ —**	$ (2)
Past service costs (credits)/plan amendments	**—**	—	**5**	(1)
Amortization of actuarial losses (gains)	**1**	(1)	**—**	—
Foreign currency translation	**1**	1	**—**	—
Income tax (recovery) expense	**(5)**	2	**—**	—
Total recognized in comprehensive income	**$ 8**	$ (1)	**$ 5**	$ (3)
Current year net actuarial losses (gains)	**$ 64**	$ 41	**$ 3**	$ (39)
Past service credits/plan amendments	**—**	—	**—**	(3)
Amortization of actuarial (losses) gains	**(23)**	(47)	**4**	—
Amortization of past service (costs) credits	**(1)**	1	**8**	11
Foreign currency translation	**(10)**	21	**—**	(3)
Regulatory adjustments	**—**	4	**(8)**	(1)
Total recognized in regulatory assets	**$ 30**	$ 20	**$ 7**	$ (35)

Significant Assumptions	Defined Benefit Pension Plans		OPEB Plans	
(weighted average %)	**2019**	2018	**2019**	2018
Discount rate during the year [(1)]	**4.05**	3.56	**4.10**	3.57
Discount rate as at December 31	**3.20**	4.07	**3.25**	4.13
Expected long-term rate of return on plan assets [(2)]	**5.78**	5.80	**5.50**	5.48
Rate of compensation increase	**3.33**	3.35	**—**	—
Health care cost trend increase as at December 31 [(3)]	**—**	—	**4.62**	4.61

(1) *ITC and UNS use the split discount rate methodology for determining current service and interest costs. All other subsidiaries use the single discount rate approach.*

(2) *Developed by management using best estimates of expected returns, volatilities and correlations for each class of asset. Best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.*

(3) *The projected 2020 weighted average health care cost trend rate is 6.15% and is assumed to decrease over the next 12 years to the weighted average ultimate health care cost trend rate of 4.62% in 2031 and thereafter.*

Expected Benefit Payments	**Defined Benefit Pension Payments**	**OPEB Payments**
(year)	*(in millions)*	*(in millions)*
2020	$ 152	$ 25
2021	156	27
2022	164	29
2023	168	30
2024	175	31
2025-2029	959	174

During 2020 the Corporation expects to contribute $46 million for defined benefit pension plans and $32 million for OPEB plans.

In 2019 the Corporation expensed $39 million (2018 - $38 million) related to defined contribution pension plans.

27. SUPPLEMENTARY CASH FLOW INFORMATION

(in millions)	2019	2018
Cash paid (received) for		
Interest	$ 1,007	$ 969
Income taxes	(37)	73
Change in working capital		
Accounts receivable and other current assets	$ 1	$ (204)
Prepaid expenses	(8)	1
Inventories	(13)	(8)
Regulatory assets - current portion	(75)	16
Accounts payable and other current liabilities	(8)	99
Regulatory liabilities - current portion	(65)	(6)
	$ (168)	$ (102)
Non-cash investing and financing activities		
Accrued capital expenditures	$ 382	$ 328
Common share dividends reinvested	299	272
Finance leases	88	223
Right-of-use assets obtained in exchange for operating lease liabilities	55	—
Contributions in aid of construction	15	14
Exercise of stock options into common shares	5	1

28. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Derivatives

The Corporation generally limits derivative usage to those qualifying as accounting, economic or cash flow hedges, or those that are otherwise approved for regulatory recovery.

The Corporation records all derivatives at fair value, with certain exceptions including those derivatives that qualify for the normal purchase and normal sale exception. Fair values reflect estimates based on current market information about the derivatives as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

Cash flows associated with the settlement of all derivatives are included in operating activities on the consolidated statements of cash flows.

Energy contracts subject to regulatory deferral
UNS Energy holds electricity power purchase contracts, customer supply contracts and gas swap contracts to reduce its exposure to energy price risk. Fair values were measured primarily under the market approach using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses.

Central Hudson holds swap contracts for electricity and natural gas to minimize price volatility by fixing the effective purchase price. Fair values were measured using forward pricing provided by independent third-party information.

FortisBC Energy holds gas supply contracts and commodity swaps to fix the effective purchase price of natural gas. Fair values reflect the present value of future cash flows based on published market prices and forward natural gas curves.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. As at December 31, 2019, unrealized losses of $119 million (December 31, 2018 - $57 million) were recognized as regulatory assets and unrealized gains of $2 million (December 31, 2018 - $9 million) were recognized as regulatory liabilities.

Energy contracts not subject to regulatory deferral
UNS Energy holds wholesale trading contracts to fix power prices and realize potential margin, of which 10% of any realized gains is shared with customers through rate stabilization accounts. Fair values were measured using a market approach utilizing independent third-party information, where possible.

Aitken Creek holds gas swap contracts to manage its exposure to changes in natural gas prices, capture natural gas price spreads, and manage the financial risk posed by physical transactions. Fair values were measured using forward pricing from published market sources.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are recognized in revenue. During 2019 unrealized losses of $16 million (2018 - unrealized losses of $12 million) were recognized in revenue.

Total return swaps
The Corporation holds total return swaps to manage the cash flow risk associated with forecasted future cash settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $111 million and terms of one to three years expiring in January 2020, 2021 and 2022. Fair value was measured using an income valuation approach based on forward pricing curves. During 2019 unrealized gains of $11 million (2018 - unrealized gains of less than $1 million) were recognized in other income, net.

Foreign exchange contracts
The Corporation holds US dollar foreign exchange contracts to help mitigate exposure to volatility of foreign exchange rates. The contracts expire in 2020 and have a combined notional amount of $166 million. Fair value was measured using independent third-party information. During 2019 unrealized gains of $11 million (2018 - unrealized losses of $11 million) were recognized in other income, net.

Interest rate swaps
During 2019 ITC entered into forward-starting interest rate swaps to manage the interest rate risk associated with the refinancing of long-term debt due in June 2021. The swaps have a combined notional value of $260 million and five-year terms with a mandatory early termination provision. The swaps will be terminated no later than the effective date of November 2020. Fair value was measured using a discounted cash flow method based on LIBOR rates. Unrealized gains and losses associated with changes in fair value are recognized in other comprehensive income, will be reclassified to earnings as a component of interest expense over the life of the debt, and were not material for 2019 and 2018.

Other investments
ITC, UNS Energy and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees. These investments consist of mutual funds and money market accounts, which are recorded at fair value based on quoted market prices in active markets. Gains and losses on these funds are recognized in other income, net and were not material for 2019 and 2018.

Recurring Fair Value Measures

The following table presents the fair value of assets and liabilities that were accounted for at fair value on a recurring basis.

($ millions)	Level 1 [(1)]	Level 2 [(1)]	Level 3 [(1)]	Total
As at December 31, 2019				
Assets				
Energy contracts subject to regulatory deferral [(2)] [(3)]	**—**	**22**	**—**	**22**
Energy contracts not subject to regulatory deferral [(2)]	**—**	**8**	**—**	**8**
Foreign exchange contracts, interest rate and total return swaps [(2)]	**14**	**4**	**—**	**18**
Other investments [(4)]	**121**	**—**	**—**	**121**
	135	**34**	**—**	**169**
Liabilities				
Energy contracts subject to regulatory deferral [(3)] [(5)]	**(1)**	**(138)**	**—**	**(139)**
Energy contracts not subject to regulatory deferral [(5)]	**—**	**(12)**	**—**	**(12)**
	(1)	**(150)**	**—**	**(151)**
As at December 31, 2018				
Assets				
Energy contracts subject to regulatory deferral [(2)] [(3)]	—	33	8	41
Energy contracts not subject to regulatory deferral [(2)]	—	13	3	16
Other investments [(4)]	155	—	—	155
	155	46	11	212
Liabilities				
Energy contracts subject to regulatory deferral [(3)] [(5)]	—	(86)	(3)	(89)
Energy contracts not subject to regulatory deferral [(5)]	—	(1)	—	(1)
Foreign exchange contracts, interest rate and total return swaps [(5)]	(8)	(1)	—	(9)
	(8)	(88)	(3)	(99)

(1) *Under the hierarchy, fair value is determined using: (i) level 1 - unadjusted quoted prices in active markets; (ii) level 2 - other pricing inputs directly or indirectly observable in the marketplace; and (iii) level 3 - unobservable inputs, used when observable inputs are not available. Classifications reflect the lowest level of input that is significant to the measurement. At December 31, 2019, all level 3 assets and liabilities transferred to level 2 because observable market data became available.*
(2) *Included in accounts receivable and other current assets or other assets*
(3) *Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates as permitted by the regulators.*
(4) *Included in other assets*
(5) *Included in accounts payable and other current liabilities or other liabilities*

The Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions, which applies only to its energy contracts. The following table presents the potential offset of counterparty netting.

Energy Contracts *($ millions)*	Gross Amount Recognized in Balance Sheet	Counterparty Netting of Energy Contracts	Cash Collateral Received / Posted	Net Amount
As at December 31, 2019				
Derivative assets	**30**	**22**	**10**	**(2)**
Derivative liabilities	**(151)**	**(22)**	**(2)**	**(127)**

Energy Contracts *($ millions)*	Gross Amount Recognized in Balance Sheet	Counterparty Netting of Energy Contracts	Cash Collateral Received/ Posted	Net Amount
As at December 31, 2018				
Derivative assets	57	28	16	13
Derivative liabilities	(90)	(28)	—	(62)

Volume of Derivative Activity

As at December 31, 2019, the Corporation had various energy contracts that will settle on various dates through 2029. The volumes related to electricity and natural gas derivatives are outlined below.

As at December 31	**2019**	2018
Energy contracts subject to regulatory deferral [(1)]		
Electricity swap contracts *(GWh)*	**628**	774
Electricity power purchase contracts *(GWh)*	**3,198**	651
Gas swap contracts *(PJ)*	**168**	203
Gas supply contract premiums *(PJ)*	**241**	266
Energy contracts not subject to regulatory deferral [(1)]		
Wholesale trading contracts *(GWh)*	**1,855**	1,440
Gas swap contracts *(PJ)*	**43**	37

(1) *GWh means gigawatt hours and PJ means petajoules.*

Credit Risk

For cash equivalents, accounts receivable and other current assets, and long-term other receivables, credit risk is generally limited to the carrying value on the consolidated balance sheets. The Corporation's subsidiaries generally have a large and diversified customer base, which minimizes the concentration of credit risk. Policies in place to minimize credit risk include requiring customer deposits, prepayments and/or credit checks for certain customers, performing disconnections and/or using third-party collection agencies for overdue accounts.

ITC has a concentration of credit risk as approximately 70% of its revenue is derived from three customers. The customers have investment-grade credit ratings and credit risk is further managed by requiring a letter of credit or cash deposit equal to the credit exposure, which is determined by a credit-scoring model and other factors.

FortisAlberta has a concentration of credit risk as distribution service billings are to a relatively small group of retailers. Credit risk is managed by obtaining from the retailers either a cash deposit, bond, letter of credit, an investment-grade credit rating, or a financial guarantee from an entity with an investment-grade credit rating.

UNS Energy, Central Hudson, FortisBC Energy, Aitken Creek and the Corporation may be exposed to credit risk from non-performance by counterparties to derivatives. Credit risk is managed by net settling payments, when possible, and dealing only with counterparties that have investment-grade credit ratings. At UNS Energy and Central Hudson, certain contractual arrangements require counterparties to post collateral.

The value of derivatives in net liability positions under contracts with credit risk-related contingent features that, if triggered, could require the posting of a like amount of collateral was $161 million as at December 31, 2019 (December 31, 2018 - $75 million).

Foreign Exchange Hedge

The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI, Belize Electric Company Limited and Belize Electricity is, or is pegged to, the US dollar. The earnings and cash flows from, and net investments in, these entities are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has limited this exposure through hedging.

As at December 31, 2019, US$2.2 billion (December 31, 2018 - US$3.4 billion) of corporately issued US dollar-denominated long-term debt has been designated as an effective hedge of foreign net investments, leaving approximately US$9.7 billion (December 31, 2018 - US$8.0 billion) unhedged. Exchange rate fluctuations associated with the hedged net investment in foreign subsidiaries and the debt serving as the hedge are recognized in accumulated other comprehensive income.

Financial Instruments Not Carried at Fair Value

Excluding long-term debt, the consolidated carrying value of the Corporation's remaining financial instruments approximates fair value, reflecting their short-term maturity, normal trade credit terms and/or nature.

As at December 31, 2019, the carrying value of long-term debt, including current portion, was $22.3 billion (December 31, 2018 - $24.2 billion) compared to an estimated fair value of $25.3 billion (December 31, 2018 - $25.1 billion).

29. COMMITMENTS AND CONTINGENCIES

As at December 31, 2019, consolidated unconditional minimum purchase obligations were as follows.

(in millions)	Total	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Waneta Expansion capacity agreement *(1)*	**$ 2,628**	51	52	53	54	55	2,363
Gas and fuel purchase obligations *(2)*	**2,398**	606	424	349	255	140	624
Power purchase obligations *(3)*	**1,743**	244	183	168	163	119	866
Renewable PPAs *(4)*	**1,513**	104	104	104	103	103	995
Build-transfer agreement - Oso Grande *(5)*	**438**	438	—	—	—	—	—
ITC easement agreement *(6)*	**401**	13	13	13	13	13	336
Renewable energy credit purchase agreements *(7)*	**124**	26	18	17	10	10	43
Debt collection agreement *(8)*	**116**	3	3	3	3	3	101
Other *(9)*	**299**	36	26	24	25	29	159
Total	**$ 9,660**	1,521	823	731	626	472	5,487

(1) FortisBC Electric entered into an agreement to purchase capacity from Waneta Expansion. In April 2019 the Waneta Expansion ceased to be a related party, resulting in the disclosure of FortisBC Electric's agreement to purchase capacity from the Waneta Expansion over the 40-year agreement that began in April 2015.

(2) *FortisBC Energy ($1.5 billion):* includes contracts for the purchase of gas, gas transportation and storage services, with expiry dates from 2020 to 2062. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2019.

UNS Energy ($775 million): includes long-term contracts for the purchase and delivery of coal to fuel generating facilities, the purchase of gas transportation services to meet load requirements, and the purchase of transmission services for purchased power. Amounts paid for coal depend on actual quantities purchased and delivered. Certain contracts have price adjustment clauses that will affect future costs. These contracts have various expiry dates between 2020 and 2040.

(3) *Maritime Electric ($669 million):* includes an agreement entitling Maritime Electric to approximately 4.55% of the output of New Brunswick Power's Point Lepreau nuclear generating station and requiring Maritime Electric to pay its share of the station's capital operating costs for the life of the unit. Maritime Electric also has two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2024.

FortisOntario ($653 million): an agreement with Hydro-Québec for the supply of up to 145 MW of capacity and a minimum of 537 GWh of associated energy annually from January 2020 through December 2030.

FortisBC Electric ($344 million): an agreement with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term beginning October 1, 2013.

(4) TEP and UNS Electric are party to renewable PPAs, with expiry dates from 2031 through 2043, that require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities once commercial operation is achieved. Amounts are the estimated future payments.

(5) In March 2019 UNS Energy entered into a build-transfer agreement to develop a wind-powered electric generation facility, the Oso Grande Wind Project, with estimated project cost of US$384 million. Construction commenced in the third quarter of 2019 and is expected to be completed by December 2020. UNS Energy made payments of US$47 million in 2019 and US$226 million in January 2020 under this agreement.

(6) ITC is party to an agreement with Consumers Energy, the primary customer of METC, which provides METC with an easement for transmission purposes and rights-of-way, leasehold interests, fee interests and licences associated with the land over which its transmission lines cross. The agreement expires in December 2050, subject to 10 potential 50-year renewals thereafter.

(7) UNS Energy and Central Hudson are party to renewable energy credit purchase agreements, mainly for the purchase of environmental attributions from retail customers with solar installations or other renewable generation. Payments are primarily made at contractually agreed-upon intervals based on metered energy production.

(8) Maritime Electric is party to a debt collection agreement with PEI Energy Corporation for the initial capital cost of the submarine cables and associated parts of the New Brunswick transmission system interconnection. Payments under the agreement, which expires in February 2056, will be collected from customers in future rates.

(9) Includes land easements, asset retirement obligations and joint-use asset and shared service agreements.

Other Commitments

Under a funding framework with the Governments of Ontario and Canada, Fortis will contribute a minimum of approximately $155 million of equity capital to the Wataynikaneyap Partnership, based on Fortis' proportionate 39% ownership interest and the final regulatory-approved capital cost of the related project. In October 2019 the Wataynikaneyap Partnership entered into loan agreements to finance the project during construction ("construction loan agreements"). In the event a lender under the construction loan agreements realizes security on the loans, Fortis may be required to accelerate its equity capital contributions, which may be in excess of the amount otherwise required of Fortis under the funding framework, to a maximum total funding of $235 million.

Central Hudson is a participant in an investment with other utilities to jointly develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with FERC for the recovery of the cost of and return on five high-voltage transmission projects totalling $2.2 billion (US$1.7 billion). Central Hudson's maximum commitment is $236 million (US$182 million), for which it has issued a parental guarantee. As at December 31, 2019, there was no obligation under this guarantee.
As at December 31, 2019, FortisBC Holdings Inc. had $78 million (December 31, 2018 - $77 million) of parental guarantees outstanding to support storage optimization activities at Aitken Creek.

Contingency

In April 2013 FHI and Fortis were named as defendants in an action in the British Columbia Supreme Court by the Coldwater Indian Band ("Band") regarding interests in a pipeline right of way on reserve lands. The pipeline was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in 2007. The Band seeks cancellation of the right of way and damages for wrongful interference with the Band's use and enjoyment of reserve lands. In May 2016 the Federal Court dismissed the Band's application for judicial review of the ministerial consent. In September 2017 the Federal Court of Appeal set aside the Minister's consent and returned the matter to the Minister for redetermination. No amount has been accrued as the outcome cannot yet be reasonably determined.